1.0 TRANSMISSION SYSTEM PLAN

The sections contained in this Exhibit form Hydro One's consolidated five-year Transmission System Plan ("TSP") for the 2020 to 2024 period (the "planning period"). The TSP has been prepared in accordance with Chapter 2 of the Ontario Energy Board's *Filing Requirements for Electricity Transmission Applications*, issued on February 11, 2016, with further guidance from Chapter 5 of the OEB's Filing Requirements (*Consolidated Distribution System Plan Filing Requirements*), issued on March 28, 2013 and revised on July 12, 2018 (together, the "Filing Requirements"). To assist parties in their review of the TSP, Hydro One has provided the applicable references to the Filing Requirements in brackets in the heading titles throughout the TSP.

On March 16, 2018 the OEB issued a letter setting out its expectations regarding future distribution rate and transmission revenue requirement applications by Hydro One. The letter directed Hydro One to file a transmission revenue requirement application for a four-year period from 2019 to 2022. Subsequently, Hydro One experienced organizational changes in July and August, 2018, which included the appointment of a new Board of Directors. As a result, Hydro One took the opportunity to re-evaluate its transmission business plan to balance the needs of customers, system reliability and overall stewardship of its assets with a particular focus on increasing productivity and minimizing rate increases.

To permit this review to occur and adhere to the OEB's objective of a combined transmission and distribution application in the future, Hydro One adopted a two-step approach. First, Hydro One filed an application for a one-year mechanistic adjustment to Hydro One's 2019 revenue requirement (EB-2018-0130). Second, Hydro One filed this 3-year Custom Incentive Rate- Setting (IR) application with a 2020-2022 test period to allow alignment with the OEB's expectation that Hydro One file a single application for distribution rates and transmission revenue requirement for the period 2023 to 2027.

Consistent with Chapter 2 of the Filing Requirements, Hydro One's TSP includes a summary of capital expenditures for five future years. However, this Application seeks approval for a revenue requirement only in respect of the 3-year period of 2020-2022. The terms "planning period" and "test period" are used accordingly throughout the TSP.

The table of contents for the TSP is provided below.

1.1 (5.2.1) TRANSMISSION SYSTEM PLAN OVERVIEW

1.1.1 (5.2.1 A) INTRODUCTION

This is the first 5-year Transmission System Plan ("TSP") prepared by Hydro One Networks Inc. ("Hydro One"). It covers a planning horizon from 2020 to 2024. Hydro One has prepared this TSP in accordance with Section 2.4 of Chapter 2 (Revenue Requirement Applications) of the Ontario Energy Board's (the "OEB" or "Board") *Filing Requirements for Electricity Transmission Applications*, issued on February 11, 2016, with further guidance from Chapter 5 of the Filing Requirements (Consolidated Distribution System Plan Filing Requirements), issued on July 12, 2018 (together, the "Filing Requirements"). The references in heading brackets denote corresponding sections of the Filing Requirements.

Consistent with the Filing Requirements, this TSP provides a consolidated set of documentation concerning Hydro One's asset management process and capital expenditure plan for its transmission system, using a standardized approach and structure. This TSP also provides related information about Hydro One's efforts to coordinate its planning with third parties, identify and take into account customer preferences, as well as measure performance to support continuous improvement.

This TSP provides a comprehensive and detailed explanation of Hydro One's capital investment plan for its transmission system in respect of the 5-year period from 2020 to 2024. Based on OEB Staff input from its letter dated March 16, 2018, and in light of subsequent organizational changes experienced by Hydro One in July and August 2018, Hydro One adopted a two-step approach. First, on October 26, 2018, Hydro One filed an application for a one-year mechanistic adjustment to determine Hydro One's 2019 revenue requirement (EB-2018-0130). Second, Hydro One is submitting this 3-year request for revenue requirement covering the period 2020-2022. This is done to align the completion of the transmission revenue requirement period with that of the Hydro One Distribution application filed on March 31, 2017 under case number EB-2017-0049, which aligns with the OEB's expectation that Hydro One file a single application for distribution rates and transmission revenue requirement with a test period commencing in 2023. For clarity, while the revenue requirement application covers the period 2020-2022, this TSP, and the capital investment plan discussed herein, covers the 5-year period from 2020-2024 in accordance with the Filing Requirements.

This plan demonstrates how Hydro One has aligned its investment planning processes and intended outcomes with the principles and expectations articulated by the OEB in the *Renewed Regulatory Framework* ("RRF"),[1] namely by focusing on identified customer preferences; continuous improvement in productivity, reliability and cost performance; public policy responsiveness; and financial performance.

To prepare this TSP, Hydro One engaged its transmission customers, its Executive Leadership Team and employees from across the company, including functions such as Planning, Customer Care, Finance, Transmission and Stations, System Operations and Regulatory Affairs. Through this significant effort, Hydro One has endeavored to carefully consider and set out, in extensive detail, its proposed transmission investment plans over the course of the planning period, along with the myriad of processes, methodologies and other considerations that, together, have enabled Hydro One to ensure its investment plans are appropriate in their focus, scope and pacing, having regard for the needs of the system, the company and its customers. Hydro One engaged in benchmarking and third party assessments to provide feedback on the condition of its assets, the strategies and approaches it employs to manage those assets and to ensure that a consistent and thorough planning process is in place. The assessments demonstrate that

[1] OEB, Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012.

recent enhancements to Hydro One's planning practices and processes address gaps identified both internally and by the OEB in the Prior Proceeding, and that the investment planning process is aligned with industry best practices.

1.1.2 (5.2.1 A) FORMAT OF THE TSP

Consistent with the Filing Requirements, Hydro One's TSP is organized into three chapters, as follows.

- **Chapter 1 – Transmission System Plan** – This chapter provides an overview of Hydro One's transmission system and the various factors and outcomes that were considered by Hydro One in developing its capital expenditure plan.
- **Chapter 2 – Asset Management Process** – This chapter reviews Hydro One's asset management and life-cycle optimization strategies, as well as its investment planning process, which determines the appropriate portfolio of investments having regard to the specific outcomes that Hydro One seeks to achieve;
- **Chapter 3 – Capital Expenditure Plan** – This chapter details Hydro One's capital expenditure plans for its transmission system for the period 2020-2024 and compares Hydro One's historical capital spending to past OEB-approved forecasts. The capital expenditure plan is the product of the investment planning process and asset management strategies described in Chapter 2, as informed and guided by the various drivers described in Chapter 1. This Chapter includes a number of Investment Summary Documents, which provide details regarding large projects with forecast spending over $3 million[2] in any given year of the 2020-2024 period.

A Table of Concordance, which aligns the sections of this TSP with the Filing Requirements, is provided in Appendix 'A'.

Unless otherwise specified, the asset information contained in this TSP is taken as of December 31, 2018. Forecast costs for the 2019 to 2024 period are as forecast in Hydro

[2] Hydro One's materiality threshold is $3 million as determined Section 2.1.1 of the OEB's Filing Requirements for Electricity Transmission Applications, dated February 11, 2016.

One's 2019-2024 Transmission Business Plan.[3] 2018 costs are based on Hydro One's Q3 forecast of 2018 and will be updated with actuals in a Blue Page update to be completed in mid-2019.

[3] The Transmission Business Plan, dated December 14, 2018, is provided as Attachment 1 to Exhibit A, Tab 3, Schedule 1.

1.1.3 RESPONSIVENESS TO OEB DECISION IN EB-2016-0160

The OEB's findings and directions in its Decision and Order on Hydro One's last transmission revenue requirement application (EB-2016-0160), have informed the preparation of this TSP. Table 1 below identifies the OEB's TSP-related areas of concern in that proceeding and describes at a high level how Hydro One has responded to that feedback in preparing the present application. Each of these aspects is elaborated upon throughout this TSP.

Table 1 – Summary of Responses to OEB Feedback on TSP in EB-2016-0160

AREA OF CONCERN	OEB FEEDBACK	HYDRO ONE ACTIONS TAKEN
Customer Engagement	The investment plan did not adequately use customer engagement feedback	Earlier, more comprehensive customer engagement Customer engagement feedback results used to inform and update risk taxonomies in line with customer needs Increased Customer Participation: Representatives from 103 customer organizations participated in the 2017 survey, relative to 62 organizations in the 2016 survey
Deficiencies in Prioritization	Questioned prioritization and optimization process	New taxonomies drive investment scoring and prioritization and optimization; Risk scores used to maximize risk mitigation per dollar spent
Asset Condition Assessments	Need a comprehensive asset condition process that informs the prioritization	Risk scores tied back to available condition assessments; Updated inventory of assets and condition assessments with identified opportunities; Third-party assessments and data initiatives performed.

AREA OF CONCERN	OEB FEEDBACK	HYDRO ONE ACTIONS TAKEN
Value Added in Review	The investment plan did not change over seven months of review	Enterprise Wide Review: Multiple challenge sessions are now held to provide a fact-based and structured approach to define the investment portfolio, with the focus on ensuring that the most valuable work to customers is included in the plan.
Sequencing	Plan was submitted for rate filing before Hydro One Board approval	Sequencing issues addressed for this filing. Plan submitted to Hydro One Board of directors in December 2018, in advance of filing
Internal Audit	Planning process had outstanding internal audit items to address	All original internal audit items are now complete; Follow up internal audit shows lower overall risk level
Work Program Delivery	Hydro One had not historically delivered its capital and OM&A programs to OEB approved level	Enhanced upfront engineering and planning deliverables; Increased governance throughout investment lifecycle; Improved estimating and scheduling tools and processes Delivered In Service Addition ("ISA") approved in 2017 rate order (872M vs. 868M) 2016 Bridge year ISA presented as part of EB-2016-0160 (910M vs. 912M)

1.1.4 (5.3.2 A, B) HYDRO ONE'S TRANSMISSION SYSTEM

This section of the TSP provides a high level description of Hydro One's transmission system, its role in Ontario's electricity system and the customers it serves. This description is provided, in part, to provide insight on how the transmission system differs from distribution systems and their associated distribution system plans. Chapter 5 of the Filing Requirements for distribution system plans was used to prepare this TSP, however, the unique aspects of Hydro One's transmission system were also necessarily taken into account in developing this TSP. Key aspects to consider include:

- Hydro One's transmission system extends to most of the province and operates in diverse geographic and climatic conditions, unlike distribution systems which generally serve smaller and more localized service territories;
- Hydro One's transmission system is a critical asset for the province, with a particularly high level of criticality for certain areas and facilities, such that significant and far-reaching impacts are likely to result from outages;
- one particularly critical aspect is the part of Hydro One's transmission system comprising the bulk electric system, which requires compliance with reliability standards established by the North American Electric Reliability Corporation ("NERC") to ensure the integrity of the interconnected North American Bulk Electric Systems;
- as the lead transmitter for most regions in the province, Hydro One must take into account Regional Planning requirements and the Long-Term Energy Plan ("LTEP") in planning its transmission investments;
- customers served by Hydro One's transmission system include large industrial end users, which depend on a reliable energy supply and high-power quality to support their facilities and industrial processes, as well as the owners and operators of local distribution systems that in turn serve end-users across the province; and
- Transmission projects tend to be multi-year in nature, as opposed to distribution projects which tend to be completed within a 12-month period.

These aspects are discussed in the sections below.

1.1.4.1 SCOPE OF THE TRANSMISSION SYSTEM AND SERVICE AREA

Hydro One is comprised of over $13 billion of transmission assets and accounts for approximately 98% of the revenues of all licensed transmitters in Ontario. The system transmits electricity throughout the Province of Ontario between supply points (i.e. generation) and delivery points (i.e. load customers). In 2017, Hydro One transmitted approximately 132 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario.

As shown in the maps provided in Figures 1 and 2, below, Hydro One's transmission service area includes both northern and southern Ontario. Whereas the majority of Ontario's population is located in the south, the northern part of the province is sparsely populated with heavy forestation. The climate across Ontario also varies significantly by location and by season. Hydro One's transmission system is susceptible to a variety of extreme weather conditions, such as blizzards, hail, ice storms, lightning, thunderstorms, extreme heat and tornadoes.

Hydro One operates its transmission system and manages responses to trouble calls from a centralized operations facility known as the Ontario Grid Control Centre ("OGCC"). A Back Up Control Centre ("BUCC") is also maintained in accordance with NERC standard Emergency Operating Procedure, EOP-008-2 "Loss of Control Centre Functionality" and the IESO Market Rules. In the event the OGCC or its computer systems are rendered unavailable, control and monitoring of the bulk electric system or IESO-controlled Grid is transferred to the BUCC. In addition, Hydro One has Service Centres located throughout the province, which serve Hydro One's transmission business as well as its distribution business, provide base locations for field crews and the materials, tools and equipment they rely upon to provide maintenance and restoration services in a timely, effective and efficient manner. Support for Hydro One's transmission system operations is provided by various corporate functions, including executive leadership, finance, human resources, legal and regulatory, which carry on business from Hydro One's head office in downtown Toronto.

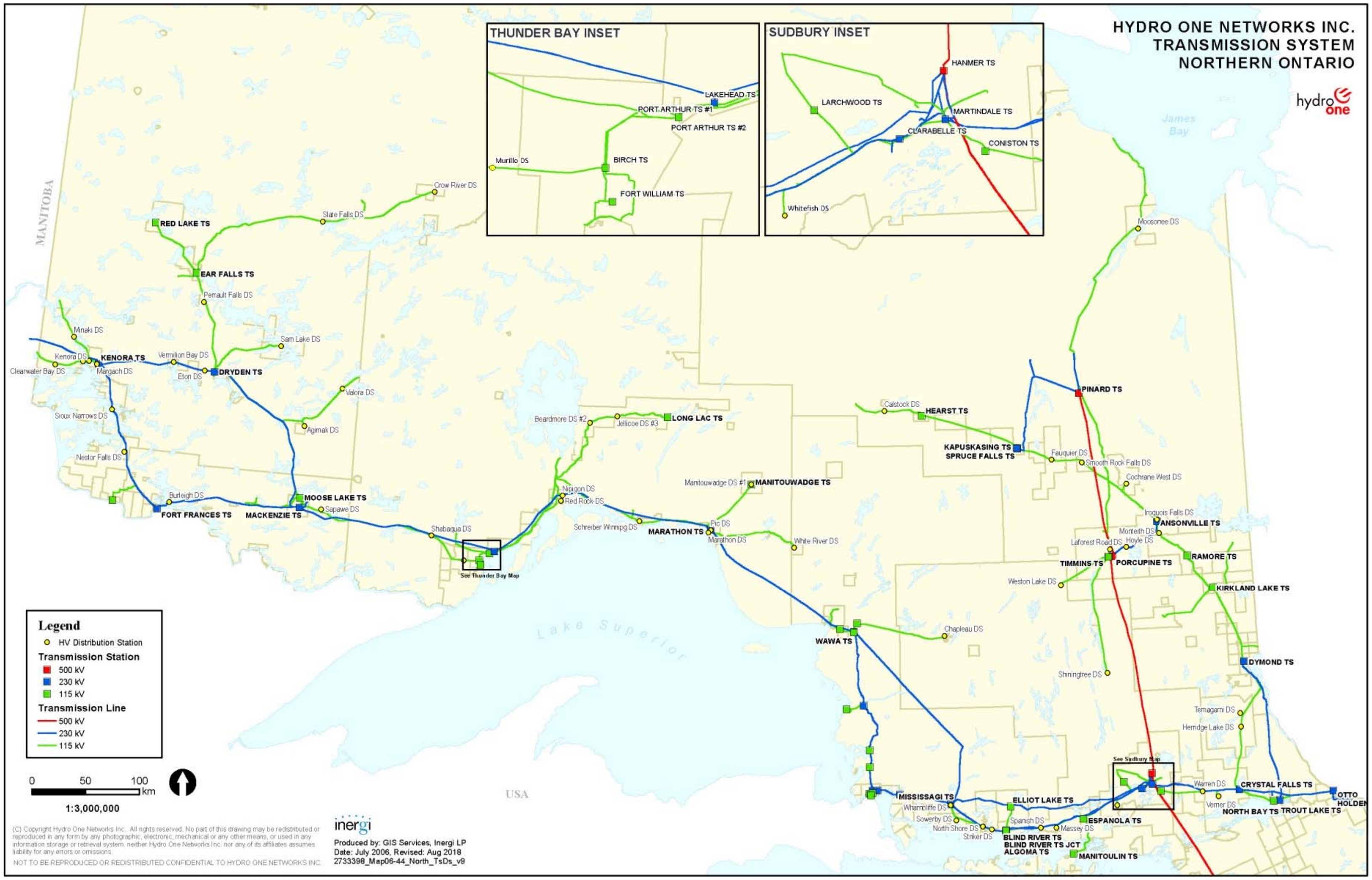

Figure 1 – Hydro One Transmission System in Northern Ontario

Figure 2 – Hydro One Transmission System in Southern Ontario

In addition to providing connections to its customer base, Hydro One's transmission system is connected with and enables the operation of all other licensed transmission systems in Ontario, namely those that are owned and operated by Canadian Niagara Power Inc., Five Nations Energy Inc., Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP), and B2M Limited Partnership.

Hydro One's transmission system interconnects with transmission systems in five neighbouring jurisdictions in Canada and the United States (Manitoba, Quebec, Minnesota, Michigan and New York) and enables electricity transactions with those jurisdictions through 26[4] interconnections, as shown in Figure 3, below. Collectively, these interconnections can accommodate theoretical maximum imports of about 6,610 MW and exports of approximately 6,121 MW of electricity in the summer months.[5] Actual import and export capabilities of the interconnections depend on limitations at the interface as well as within Hydro One's system and the transmission systems in other jurisdictions.

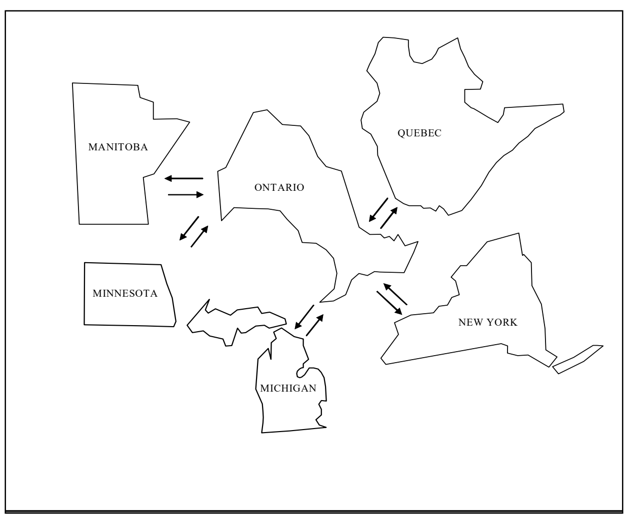

Figure 3 – Existing Ontario Transmission Interconnections

[4] The number of interconnections will increase as a result of the Lake Erie interconnection project (SS-03).
[5] From the IESO Ontario Transmission System report June 20, 2018

Hydro One's transmission system is generally comprised of three types of infrastructure – transmission lines, transmission stations and network operations facilities. A simplified figure showing how the transmission system is configured, relative to the generating stations and distribution systems that it serves, is provided in Figure 4, below.

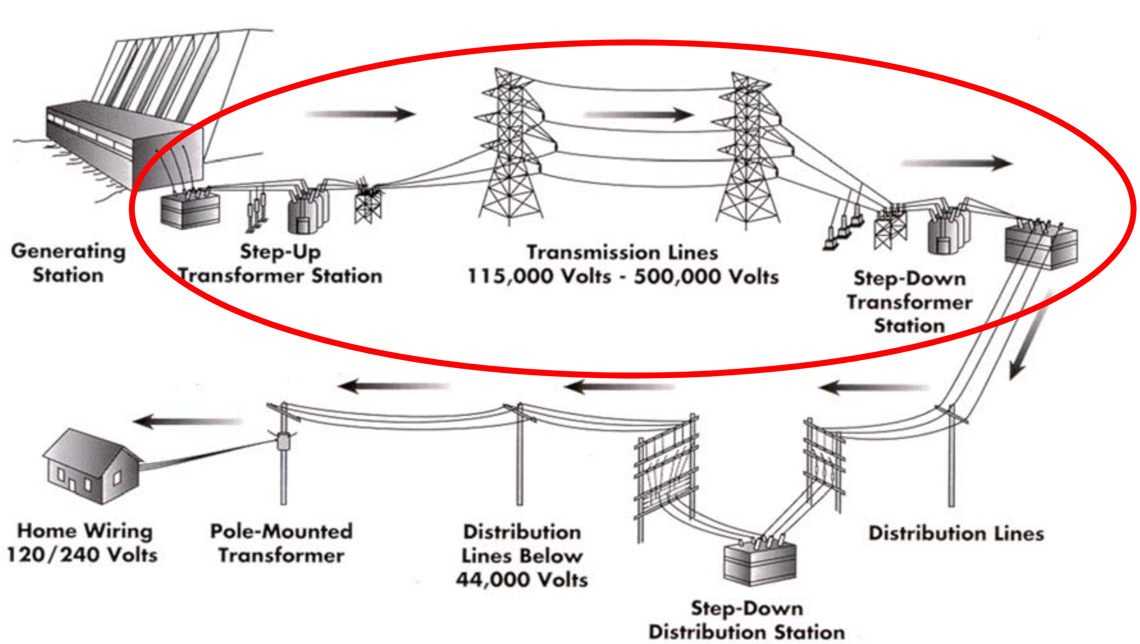

Figure 4 – Schematic Diagram of Hydro One's Transmission System

Hydro One operates transmission lines primarily at 500 kV, 230 kV and 115 kV, with minor lengths operating at 345 kV. These lines are used to transmit electric power to connected industrial and commercial customers, as well as to LDCs who in turn distribute the power to end-use customers. Hydro One's bulk transmission lines (discussed further below) deliver power from generating stations or connections to receiving stations. Area supply lines take power from the network and transmit it to customer supply transmission stations at customer load centres. Almost all of Hydro One's transmission lines are overhead. Approximately 69% of the overhead transmission lines are erected on steel structures with the other 31% supported by wood pole structures (primarily for the 115kV system).

The major components of transmission lines include overhead conductors, underground cables, steel and wood pole structures, foundations, insulators, shield wire, switches and line hardware. Transmission lines are located on lands owned either by the Ontario government, Hydro One or other parties with whom Hydro One has agreements with respect to occupancy and access rights. Approximately 70% of the delivery points on Hydro One's transmission system are multi-circuit delivery points, meaning more than one line is normally available to supply the customers connected to such a delivery point. The remainder of the transmission system features single-circuit delivery points. The high proportion of multi-circuit delivery points on Hydro One's transmission system enables Hydro One to provide a high level of reliability for the customers that it serves.

Along with high voltage transmission lines, transmission stations are the other broad category of infrastructure that is critical to the function of Hydro One's transmission system. Transmission stations are used for the delivery of power, voltage transformation and switching, and serve as connection points for load and generator customers, as well as neighbouring Ontario transmission systems and neighbouring provincial and state jurisdictions.

Hydro One's transmission stations are designed based on a range of transformer and breaker configurations to ensure redundancy, such that a loss of any one element (such as a transformer or a breaker) at a transmission station will not result in the interruption of service to customers under normal conditions. Redundancy also allows for assets to be removed from service for maintenance without an interruption to Hydro One's ability to provide transmission service to customers. This capability helps support reliability. The major components of transmission stations include power transformers, circuit breakers, disconnect switches, bus work, insulators, power cables, surge arrestors, capacitor banks, reactors, station service, grounding systems, protection and telecom systems, site infrastructure and buildings.

Hydro One's network operations are carried out from the Ontario Grid Control Centre, which manages all of Hydro One's transmission operations. As noted, Hydro One's system also includes a Back-Up Control Centre to support reliable operation of the system.

In addition to high voltage lines and transmission stations, Hydro One's transmission business requires a fleet of general plant assets (including real estate and facilities, transport and work equipment, as well as information technology), which do not directly form part of the transmission system but are critical to its function and reliability. A snapshot of Hydro One's key transmission system-related assets is presented in Table 2, below.

Table 2 - Hydro One's Key Transmission System Assets

System Assets	Total
Operating Centres	2
Transmission Circuits (Total Number)	515
Length of Overhead Transmission Lines (Total Circuit km)	29,107
Length of Underground Transmission Cables (Total Circuit km)	264
Transmission Stations (Total Number)	294
Installed Transformer Nameplate Capacity (MVA)	118,735

Data as of December 31, 2018

1.1.4.2 CRITICALITY OF THE TRANSMISSION SYSTEM

Given the scope of Hydro One's transmission system and the scale of the territory that it serves, Hydro One's transmission system is critical infrastructure for the Province of Ontario. The role of Hydro One's transmission system within the province is consistent with the definition of "critical infrastructure" that has been adopted by the Province for purposes of the Ontario Critical Infrastructure Assurance Program, which considers such infrastructure to include "interdependent, interactive, interconnected networks of institutions, services, systems and processes that meet vital human needs, sustain the economy, protect public safety and security, and maintain continuity of and confidence in government".[6] It is because of this critical role in Ontario's electricity system that the transmission system has been referred to as the "backbone" of Ontario's electricity system.[7]

Relative to the numerous distribution systems that serve individual communities throughout Ontario, there is perhaps a greater need to ensure the reliability of Hydro One's transmission system. A strong recognition of this need was a defining characteristic for how the transmission system, which Hydro One inherited from the former Ontario Hydro, was initially designed and it has been a quality that has endured ever since. With this focus and the historical experience of transmission customers in Ontario, these customers have expressed a strong preference for a low frequency of outages and a high level of reliability. These objectives are supported by the high degree of redundancy that is built into the design of Hydro One's system. Hydro One's transmission system, particularly in the southern portion of Ontario, provides customers with a high level of redundancy that ensures a level of reliability that is proportionate to the system's critical role within the province.

In addition to Hydro One's objective of continuing to ensure a high level of reliability for the transmission system to meet customer expectations and preferences, Hydro One's approach to maintaining, managing and investing in its transmission system is driven by its need to comply with a framework of reliability standards that specifically applies to those portions of its system that are part of the bulk electric system ("BES"). Hydro One applies the NERC definition of the BES that was approved by the Federal Energy Regulatory Commission ("FERC") effective July 1, 2014. NERC defines the BES as

[6] See https://www.emergencymanagementontario.ca/english/emcommunity/ProvincialPrograms/ci/ci.html
[7] Ontario's 2010 Long-Term Energy Plan: Building Our Clean Energy Future, p. 41.

including all transmission facilities greater than 100 kV, which encompasses the vast majority of Ontario's (and Hydro One's) transmission facilities.

The reliability framework for Ontario's electricity transmission system is based on the reliability standards established by NERC, which have been adopted and are enforced in Ontario by the IESO. These standards are intended to ensure the integrity not only of the Ontario BES but of all of the interconnected BESs across North America. To achieve this, among its many activities, NERC develops and enforces reliability standards, monitors the bulk power system, assesses and reports on future transmission and generation adequacy, and offers education and certification programs to industry personnel.

NERC works with eight regional entities to improve the reliability of the bulk power system, including the Northeast Power Coordinating Council ("NPCC"). NPCC develops regional reliability standards, monitors and enforces compliance, and coordinates regional system planning, design and operations, and assessments of reliability. Hydro One is a member of NPCC and is registered under NERC's compliance registry.

Following the 2003 Northeast blackout, the U.S. *Energy Policy Act of 2005* authorized the creation of a self-regulatory Electricity Reliability Organization ("ERO") that would span North America, under the oversight of FERC in the U.S. The legislation states that compliance with reliability standards is mandatory and enforceable. In July 2006, Federal Energy Regulatory Commission ("FERC") certified NERC as the ERO in the United States. In October 2006, the OEB signed a memorandum of understanding with NERC recognizing NERC as the ERO in Ontario. According to this memorandum of understanding with NERC and the IESO's Market Rules, only the IESO is directly subject to the Compliance Monitoring and Enforcing Program of NERC and NPCC in Ontario. The IESO through its Market Assessment and Compliance Division, in turn, enforces the NERC reliability standards and NPCC criteria through the Market Rules.

As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards adopted by NERC and NPCC. Hydro One actively participates with the other transmission system owners and operators on NPCC committees and task forces to coordinate planning and operations in the northeast region. There are approximately 90 Hydro One transmission stations[8] that include assets designated as part of the BES. To comply with NERC and NPCC reliability standards, these BES stations are equipped with multiple, redundant and robust protection and control systems to ensure that faults are isolated so as to prevent cascading and damage to assets near the fault. Infrastructure relating to key sites and processes is designed to adhere to NERC Critical Infrastructure Protection ("CIP") requirements. For example, sites subject to NERC and/or NPCC requirements require additional equipment, such as protection systems and station battery systems, and must meet additional CIP requirements, such as physical and electronic/cyber-security to prevent unauthorized network access. Hydro One's maintenance and investment plans are prioritized so as to maintain compliance with these requirements.

1.1.4.3 (5.2.1 G) CONSIDERATION FOR REGIONAL PLANNING AND LTEP

One of the key guiding principles from the Board's RRF is that planning transmission infrastructure with key stakeholders in a regional context helps promote the cost effective development of electricity infrastructure in Ontario. The RRF states that infrastructure planning on a regional basis, between licensed transmitters and distributors, is to be undertaken to ensure that regional issues and requirements are integrated into the utility's planning processes.

Consistent with the important role that Hydro One's transmission business plays in Ontario's regional planning process, as well as in bulk system planning, the Chapter 2

[8] Designation of BES facilities is based on the BUS structures. Some Hydro One stations contain more than 1 BUS network.

Filing Requirements identify distinct elements that must be included in a TSP but which are not required in a distribution system plan. The TSP reflects the company's discussion of needs identified through the regional planning process, the needs and preferences of customers, overall system planning policy objectives, and commitments arising from the Long Term Energy Plan. With respect to regional planning, a TSP is specifically required to include lead transmitter documentation for all applicable regions.[9]

There are a total of 21 regional planning zones in Ontario.[10] Given Hydro One's role as the lead transmitter for 19 of these regional planning zones, the extent to which regional planning has been considered in preparing this TSP is greater than the effect of regional planning on a typical distribution system plan. As described in TSP Section 1.2, there are a total of forty-six transmission investments arising from Hydro One's involvement in regional planning initiatives that it proposes to put into service during the 2020 to 2024 planning period. In a distribution system plan, a distributor is expected to describe its involvement in any regional planning initiatives and provide a copy of the final deliverables from such initiatives or the status thereof. Whereas Ontario's distributors may be involved in regional planning initiatives in respect of perhaps one or two regional planning zones, as the upstream transmitter for all of the regional planning zones, Hydro One has participated in regional planning working groups for 19 of the 21 regional planning zones. As such, Hydro One's transmission business is actively involved in the regional planning process and leading the development of regional infrastructure plans.

1.1.4.4 (5.2.1 G) TRANSMISSION-CONNECTED CUSTOMERS

Another important distinction between Hydro One's transmission system and the distribution systems that are the subject of the distribution system plans that the OEB typically reviews is the range of customers served. Whereas an LDC typically serves a

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[9] Chapter 2 Filing Requirements, Section 2.4.2, p. 14.
[10] See Appendices 3 and 4 in Planning Process Working Group Report to the Board – The Process for Regional Infrastructure Planning in Ontario, May 17, 2013.

range of customers including residential, commercial, municipal and smaller industrial customers, and small embedded generation facilities, the customers served by Hydro One's transmission system are comprised of large electricity generators, large industrial end-users, and Ontario's LDCs. In addition, Hydro One's transmission system includes inter-jurisdictional interties that are relied upon by the IESO to balance electricity supply with system demand.

Depending on the configuration and ownership of a customer's facilities, Hydro One provides its transmission customers with one or more of the following transmission services:

- Network Connection Service – for use of assets built for the common benefit of all customers;
- Line Connection Service – for use of facilities that step down the voltage from above 50 kV to below 50 kV;
- Transformation Connection Service – for all other assets not included in the Network Connection or Line Connection pools – generally those assets built for use by a specific customer(s); and
- Wholesale Revenue Meter Service – for parties that purchase electricity in the IESO-administered markets or directly from a generator.

A profile of the customer base connected to Hydro One's transmission system is presented in Table 3, below.

Table 3 – Hydro One's Transmission-Connected Customers[11]

Customer Type	Number Served
Generators	131
End Users (Large Industrial Customers)	84
Local Distribution Companies	42

Generation customers that are directly connected to Hydro One's transmission system have a combined generation capacity of approximately 35,441 MW, which represents approximately 96% of the total generation capacity[12] in the Province of Ontario. These vital assets include most of Ontario's hydroelectric generation facilities, all natural gas fueled generation facilities, large renewable generation facilities and all of Ontario's nuclear generation facilities. A transmission outage affecting service to one of these facilities affects the generation supply for Ontario, which can affect the reliability of supply and the price of electricity for all Ontario customers. Moreover, transmission outages can affect generation facility equipment and cause those stations to shut down for extended periods at a significant cost to generators, which costs may ultimately be borne by ratepayers. These customers are actively engaged in the energy sector and, as such, are sophisticated and well aware of the trade-offs between cost and reliability risk.

The large industrial customers that are directly connected to Hydro One's transmission system are a critical part of Ontario's economy and, together, accounted for 1,785 MW of electricity demand in 2017, with an estimated 4% direct contribution to Ontario's GDP and a 28% contribution to Ontario's industrial GDP. These include, for instance, customer facilities for steel production, auto manufacturing, pulp and paper, chemical processing and mining. Typically, reliability and power quality for these large industrial customers are significant factors for their decisions to locate in and remain located in

[11] The number of customers in this table is based on the number of Transmission Connection Agreements (TCA) as required by the Transmission System Code ("TSC") with the exception of LDCs that are based on their Electricity Distribution License as of December 31, 2018. This differs from the number of business entities surveyed in the Customer Engagement survey, 156, as many entities hold multiple TCAs.
[12] Total Generation Capacity of Ontario is 36,928 MW (Source: IESO Reliability Outlook Winter 2018, December 17, 2018).

Ontario. Transmission outages or power quality issues can cause significant and costly interruptions to industrial processes and customer equipment, which in turn can affect company safety, performance, and employment. Hydro One developed a plan that brings reliability and power quality to these customers and which supports their businesses and Ontario's economy. These customers are sophisticated and well aware of the trade-offs between cost and reliability/power quality risk.

The LDCs that are served by Hydro One's transmission system serve most of Ontario's residential, commercial, institutional and small industrial end-users. The end-user facilities that are indirectly affected by the reliability and performance of Hydro One's transmission system include critical infrastructure such as telecommunications systems, water and wastewater treatment facilities, hospitals and other health care facilities, airports and transportation systems, schools and universities, as well as financial services systems. Like Hydro One's generation customers, these LDC customers are actively engaged in the energy sector and, as such, are sophisticated and well aware of the trade-offs between cost and reliability risk. So too are the neighbouring Ontario transmitters that are connected to Hydro One's transmission system, who would themselves have customers that include generators, large industrial customers and LDC customers.

1.1.5 (5.2.1 A) SUMMARY OF THE INVESTMENT PLANNING PROCESS

This section provides a summary of Hydro One’s investment planning process, including (i) Hydro One’s strategic priorities and the key elements of the OEB’s policy framework that have informed the process, (ii) the outcomes that Hydro One seeks to achieve by implementing the investments identified through the process, (iii) the manner in which Hydro One has engaged with customers and factored the resulting feedback into its process and investment plans, (iv) the manner in which regional planning considerations have been addressed, (v) the key steps and outputs from its investment planning process, and (vi) the key aspects of the proposed capital expenditure plan arising therefrom.

1.1.5.1 STRATEGIC OBJECTIVES

The investment planning process that has informed this TSP was guided by a list of strategic priorities. These priorities are as follows:

Strategic Priorities

- **Employees**
  - Maintain a safe and inclusive workplace for all employees
  - Foster a high level of employee engagement throughout Hydro One through a new engagement approach focused on developing company –wide action plans ("Time for Action")
- **Customer Experience**
  - Deliver industry-leading customer service, in response to identified customer preferences
  - Foster innovation in the business to adapt to changing customer requirements and market opportunities
  - Advance reconciliation and work proactively to build relationships with Indigenous peoples and communities based on understanding, respect and mutual trust
- **Operational Effectiveness**
  - Invest in grid infrastructure and grid modernization to deliver a high level of reliability and quality to our customers
  - Focus on continuous improvement in productivity and operating efficiency to maintain lowest possible costs
- **Government and Regulatory Relationships**
  - Maintain and build constructive, transparent relationships with governments and regulatory entities in all jurisdictions where we operate
  - Deliver on obligations mandated by government through legislation and regulatory requirements
- **Financial Strength**
  - Maintain a strong balance sheet to support continuing investment in our business
  - Invest in assets to better serve customers

SAFETY COMES FIRST | STAND FOR PEOPLE | EMPOWERED TO ACT | OPTIMISM CHARGES US | WIN AS ONE

Figure 5 – Hydro One's 2018 Strategic Priorities

Figure 6 highlights the close alignment between Hydro One's planned transmission investments and the company's strategic priorities.

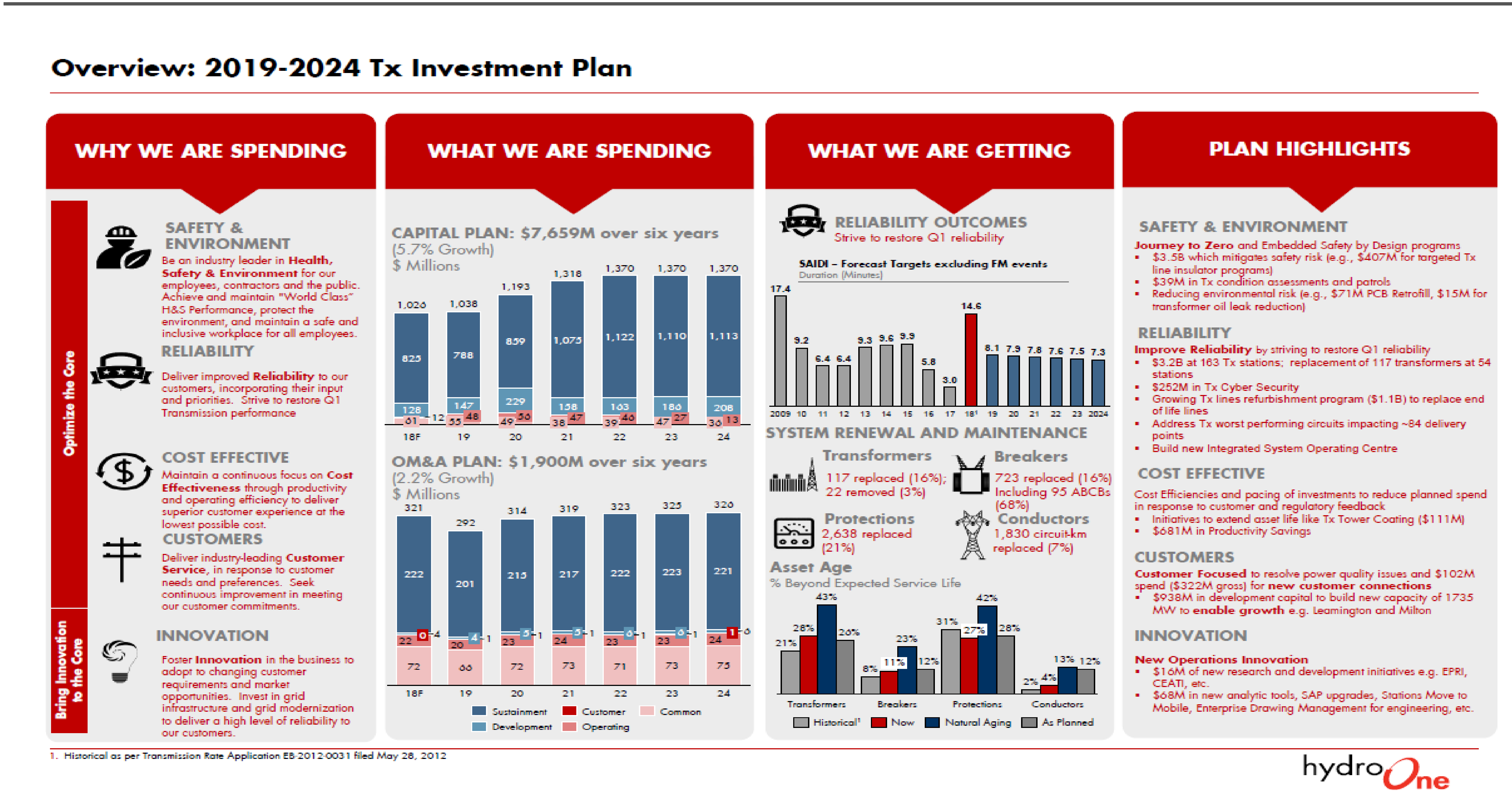


Figure 6 - Alignment Between Strategic Priorities and Planned Transmission Investments

These strategic priorities and objectives, together with the guidance provided by the OEB's policy framework, in particular, customer engagement, helped inform the investment plan that is included in this TSP. Moreover, there is close alignment between the company's priorities and objectives and the themes and outcomes that the OEB has articulated through its policy framework, discussed below.

1.1.5.2 POLICY FRAMEWORK

In this TSP, Hydro One recognizes and seeks alignment with the policy framework established by the OEB through the RRF and related guidance. Hydro One understands, and has made significant efforts to embrace, the objectives of the RRF in planning and operating its transmission system. In particular, Hydro One has developed an outcomes-based plan that provides value to its transmission customers by being responsive to their identified needs and preferences, addressing regional and bulk system needs and specific system access requirements, driving productivity improvements and promoting innovation and continuous improvement.

Through this approach, Hydro One is confident that it has achieved an appropriate balance between the imperatives of meeting its compliance requirements, providing prudent stewardship over its transmission system assets, responsibly managing health and safety risks, responding to customer needs and preferences, and achieving sustainable financial performance.

Accordingly, the TSP in general, and the asset management process and capital expenditure plan in particular, demonstrate Hydro One's orientation around the following outcomes identified by the OEB in the RRF:

- **Customer Focus*:*** Services are provided in a manner that responds to identified customer preferences;

- **Operational Effectiveness***:* Continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives;
- **Public Policy Responsiveness***:* Utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
- **Financial Performance***:* Financial viability is maintained, and savings from operational effectiveness are sustainable.

1.1.5.3 OUTCOMES TO BE ACHIEVED

The key outcomes that Hydro One seeks to achieve through implementation of the asset management process and capital expenditure plan as set out in this TSP include, but are not limited to:

- **Customer Focus**: power quality improvements; improve customer reliability
- **Operational Effectiveness**: an injury-free workplace, minimized long-term costs to maintain the transmission system infrastructure and improve reliability, and restore top quartile reliability performance by mitigating risk arising from asset deterioration;
- **Public Policy Responsiveness**: continued compliance with regulatory requirements and applicable reliability standards; and
- **Financial Performance**: manageable and stable rate impacts over the course of the planning period.

The close alignment between the RRF outcomes and the outcomes that Hydro One seeks to achieve through implementation of this TSP is demonstrated from the following summary of the company's transmission business values and objectives, which is included in its 2019-2024 Transmission Business Plan and in TSP Section 1.5.

Customer Focus	**Customer Satisfaction**	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes
Operational Effectiveness	**Cost Control**	• Actively control and lower costs through OM&A and capital efficiencies
	Safety	• Drive towards achieving an injury-free workplace
	Employee Engagement	• Achieve and maintain employee engagement
	System Reliability	• Provide top quartile reliability relative to transmission peers
Public Policy Responsiveness	**Public Policy Responsiveness**	• Ensure compliance with all codes, standards and regulations • Partner in the economic success of Ontario
	Environment	• Sustainably manage our environmental footprint
Financial Performance	**Financial Performance**	• Achieve the ROE allowed by the OEB

Figure 7 – Hydro One's Transmission Business Values and Objectives

1.1.5.4 (5.2.1 B) CUSTOMER ENGAGEMENT

Hydro One undertakes a broad range of ongoing customer engagement activities in connection with its transmission system and incorporates the feedback it receives from these activities directly into its investment planning process, both at the outset and throughout that process. Hydro One's understanding of its customer needs and preferences is derived largely from six sources, as follows.

The first source is the Large Customer Account Management Group. The Large Customer Account Management group provides a single point of contact for customers for all types of interactions other than real-time operations, operating events and outage planning. This group facilitates direct communications with transmission customers on a variety of matters including customer connection requests, sustainment and system development plans and projects, and concerns regarding service level or power quality. Communication with this group prior to the Investment Plan prioritization and optimization process enabled Hydro One to identify investments that were aligned with key customer priorities such as improving reliability and power quality. This aspect of the investment planning process is described in Section 1.3.

The second source is the OGCC's Customer Operating Support Group. The OGCC's Customer Operating Support Group has direct communications with transmission customers regarding real-time operations, the coordination of planned outages, responses to unexpected outages, and the coordination of switching activities. This group also organizes bi-annual customer meetings to coordinate outage planning and, on a weekly basis, sends individual customers reports of planned outages affecting their specific delivery point, as well as post-event investigation reports following unplanned outages. In addition, this group holds transmission-connected customer conferences to share information about Hydro One's plans for the year ahead. The key messages derived from customers through these efforts are shared with Hydro One's Large Customer Account Management group so as to help inform the ongoing tracking of customer needs and priorities.

The third source is a Large Customer Conference which is held annually for all of Hydro One's large transmission and large distribution customers. At the conference, customers are presented with information about significant Hydro One initiatives, upcoming technology changes, and other initiatives that might affect them. Specific sessions, including interactive panel discussions, are held during which Hydro One presents an overview of its upcoming investments and activities. Customers also have an opportunity to meet with and provide input and share concerns with Hydro One staff and members of the senior leadership team. Hydro One obtains initial indications about customer needs and preferences by soliciting input for the conference agenda. In addition, Hydro One's Planners attend the conference, meet directly with customers and receive a summary of feedback received through a post-conference survey.

The fourth source is a series of oversight committees established by Hydro One to actively track areas of high customer interest, where careful ongoing coordination of effort with other entities is valuable, and/or where coordinated health and safety oversight is of benefit. Committees include representatives from the various affected stakeholders and meet periodically. These are focused on Sarnia area reliability, OPG and Bruce Power switchyard oversight, Toronto Hydro, Hydro Ottawa, Metrolinx, Alectra project impacts and an LDC working group. Deliverables from these oversight committees provide Hydro One Planners with additional information to support investment candidate selection decisions.

The fifth source is customer satisfaction research. Hydro One obtains customer input by means of a formalized customer satisfaction research process that has been ongoing since 1999. All research is conducted by independent expert consumer research firms, most recently by Innovative Research Group ("IRG"), a third party research firm. Hydro One's Overall Customer Satisfaction was 90 per cent for 2018. Perhaps the most significant benefit of the survey is the comments provided by customers. These comments help Hydro One understand those areas which require investment focus over the planning cycle.

The final source is a customer survey. In anticipation of this Application, Hydro One undertook a Transmission Customer Engagement Survey to identify the needs and preferences of its transmission-connected customers. Content for the survey was the result of preliminary work performed by Hydro One to address lessons learned from the 2016 Transmission Customer Engagement effort, feedback received from intervenors in the last Transmission survey, and work performed with IRG. The objective was to craft a framework through which Hydro One could obtain information to guide its investment and business plans in an unbiased manner.

The Transmission Customer Engagement Survey was carried out on Hydro One's behalf by IRG. Customers participated in the survey through a customized website created and hosted by IRG to ensure that all data was collected in a private and secure manner. Hydro One and IRG made efforts to contact all Hydro One transmission customers to participate in this engagement, either by email, phone call or in-person. As indicated in the IRG Report, a copy of which is included in TSP Section 1.3.7, the results represent the opinions of the majority of customers as the survey response rate was 66%, or 103 of 153 customers. Response rates were 51% higher than those of the 2016 Transmission Customer Engagement that was reported on in Hydro One's last transmission rate filing (EB-2016-0160). In addition, a portion of the LDCs who participated in the survey based their input on the results of their own customer engagement activities so that feedback from LDC end-users is also reflected in the TSP. The resulting customer feedback indicated the following priorities:

- Safety, reliability, and outage restoration are Hydro One customers' top priority outcomes.
- All customer segments prefer to see investments spread out over time versus investing now with higher rates in short term and lower future increases or delaying investments with lower rates in the short term and higher future rates.
- Reducing the frequency of outages is more important than reducing the duration. However, the most important issue is to reduce the number of day-to-day interruptions.
- When presented with several investment scenarios, the majority of customers preferred investment levels in line with the investment plan that was before the OEB in the 2017 to 2018 proceeding[13] by at least a three to one margin. It is seen as

[13] The total 5 year capital investment plan associated with Scenario C was $6.6B from 2019-2023. The total 5 year capital investment plan included in the 2017-2018 transmission rate application was $6.1B.

reflective of the current approach which has served the system well, and a less risky option.

- About half of end-user participants (19 of 38) rate power quality as an "extremely important" outcome.

These preferences have been consistently reiterated in Hydro One's regular touch points with its customers, as described above in this section.

The Transmission Customer Engagement Survey was carried out sufficiently in advance of the present application so as to allow an opportunity for Hydro One management to hold a series of cross functional sessions to review the findings, trends and specific customer needs and preferences identified by the survey. In addition, processes were put in place to ensure that these needs and preferences, as well as those identified through Hydro One's other customer engagement initiatives, have been appropriately captured in the investment planning process to improve alignment between individual candidate investments identified by planners and the outcomes of the customer engagement activities. Feedback obtained through Hydro One's ongoing engagement initiatives since the survey are aligned with these results.

Through the incorporation of feedback received from the broad range of customer engagement activities into the TSP, Hydro One has been able to determine a funding envelope that balances its considerations of rate impacts, customer needs and preferences, as well as operational and compliance needs. These considerations are integral to the review and final approval of the Business Plan by Hydro One's Executive Leadership Team and its Board of Directors.

In addition, the enhancements made to Hydro One's customer engagement process are responsive to the concerns raised by the OEB in its Decision and Order on Hydro One's last transmission rate application (EB-2016-0160), issued on September 28, 2017 and revised November 1, 2017. In that decision, the OEB expressed concerns with certain aspects of the customer engagement process, particularly the need for Hydro One to (i) start its customer engagement process sufficiently in advance of filing its transmission rate application to allow for customer input to be incorporated in a meaningful way and to improve the level of participation, (ii) discuss with LDC customers practical ways to seek input from their end-users, and (iii) present information to customers in a manner that is unambiguous and easy to understand.

As noted, Hydro One's Transmission Customer Engagement Survey was carried out sufficiently in advance of this Application, which allowed an opportunity for a series of cross functional sessions within the company to review findings and ensure that identified needs and preferences have been appropriately captured in investment planning. To support the survey, Hydro One worked with IRG to develop clear materials through which Hydro One could obtain information to guide its investment and business plans in an unbiased manner. In addition, a portion of the LDCs who participated in the survey based their input on the results of their own customer engagement activities so that feedback from LDC end-users is also reflected in the TSP. In response to the OEB's finding that it should seek timely and meaningful input from First Nations and Métis representatives, please see TSP Section 1.3 and Exhibit A, Tab 7, Schedule 2 of the Application.

Moving forward, Hydro One is implementing a new Ongoing Customer Engagement Questionnaire that will quantify transmission customer's satisfaction regarding a number of reliability focused measurements. The questionnaire asks about customer satisfaction with Hydro One's current work program; satisfaction with outages, power quality, and reliability; investment priorities; unplanned outages mitigation and impact; and rate impacts. The results of this annual questionnaire will input directly into Hydro One's Customer Relationship Management system and will inform the planning process. Currently, directly connected transmission customers receive an annual reliability report which summarizes performance at transmission and distribution delivery points. The report summarizes the number of Delivery Point Interruptions each customer has every year, on both the transmission and distribution system. The reliability report will allow customers to provide more informed input into customer engagement, such as Hydro One's new Ongoing Customer Engagement Questionnaire.

1.1.5.5 (5.2.1 A) REGIONAL PLANNING

The policy framework for regional planning and the extent to which it affects investment planning for Hydro One's transmission system is described in greater detail in TSP Section 1.2. The RRF requires that infrastructure planning be undertaken on a regional basis to ensure that regional issues and requirements are integrated into a utility's planning processes. As indicated, Hydro One participated in working groups comprised of representatives from the IESO, LDCs and other stakeholder groups for 19 of the 21 regions across the province where Hydro One is the lead transmitter. Hydro One's participation in these regional planning initiatives led to the identification of over 60 transmission investments, with 46 investments totalling approximately $1.4 billion in gross capital expenditures, which Hydro One proposes to implement and bring into service during the 2020 to 2024 planning period. The remaining 14 projects are planned to go in-service outside of the planning period. The number of projects by Group and Region are identified in Table 4 below, with further details on each of the projects set out in Section 1.2.

Table 4 – Number of Projects Identified in Regional Planning by Group and Region Planned for In Service between 2020-2024

Group	Region	Number of Projects
1	Burlington to Nanticoke	7
	Greater Ottawa	8
	GTA West	2
	Kitchener-Waterloo-Cambridge-Guelph	3
	Metro Toronto	12
	Northwest Ontario	1
	Windsor-Essex	6
2	London Area	2
	South Georgian Bay/Muskoka	4
3	Chatham/Lambton/Sarnia	1
	Total	**46**

1.1.5.6 (5.2.1 F) TRANSMISSION PLANNING PROCESS

Hydro One's Transmission Planning Process is comprised of a comprehensive and sophisticated process for managing its extensive transmission system assets and prudently planning its transmission investments. This process takes into account, and strives to produce, outcomes that are consistent with those identified in the RRF and that include the specific outcomes, identified through customer engagement, as described above and in TSP Section 1.3. The components of the process are set out in Figure 8 below.

Figure 8 – Hydro One's Transmission Planning Process

The core aspect of Hydro One's Transmission Planning Process is its Capital Planning Process. The Capital Planning Process refers to those aspects of the Transmission

Planning Process that involve identifying, developing and scoping investment candidates, prioritizing the portfolio of investment candidates based on risk, culminating with executive approval of a specific capital plan. Within the broader context of the Transmission Planning Process, the Capital Planning Process is informed by Hydro One's investment planning context, which includes Hydro One's strategic vision, planning and other relevant economic assumptions, customer engagement feedback, delivery of key outcomes, and overall assessment of the needs of Hydro One's assets, customers and other stakeholders.

Hydro One's Capital Planning Process consists of two interrelated functions. The first is a thorough and ongoing asset management process that involves monitoring and reviewing transmission assets and assessing their condition, assessing system and customer requirements through the regional planning process and customer connection process, as well as identifying and scoping investment candidates ("Asset Management"). This is followed by a risk-based investment planning process through which investment candidates are reviewed, prioritized and narrowed into an achievable set of planned investments in specific programs and projects that help drive Hydro One towards achieving its intended outcomes ("Investment Planning").

In its Decision and Order in Hydro One's last transmission rate proceeding (EB-2016-0160), the OEB required Hydro One to complete an independent third-party assessment of its TSP, including an assessment of its asset condition assessment and capital investment planning processes. Hydro One engaged Metsco Energy Solutions to review its asset condition assessment process and the Boston Consulting Group to review its capital investment planning process. The Metsco Energy Solutions and Boston Consulting Group reports are discussed and provided in TSP Section 1.4. Generally, Metsco Energy Solutions found that both the Asset Risk Assessment and Asset Analytics align with other asset management frameworks found elsewhere in the industry and are sufficiently rigorous and robust to accomplish their intended tasks from an analytical perspective. The Boston Consulting Group found that Hydro One has implemented a consistent and thorough capital investment planning process that meets or exceeds expectations for an above average utility planning process in all aspects.

Hydro One's Capital Expenditure Plan, as set out in Section 3 of this TSP, itemizes the specific programs and projects that have received executive approval for implementation through the Capital Planning Process. Hydro One's Asset Management and Investment Planning processes are summarized below and are discussed in greater detail in Section 2.

Asset Management

Hydro One's Asset Management process draws upon the company's deep expertise in a variety of disciplines - management, financial, economic, engineering, operations – to monitor its transmission system assets, identify and define needs, and determine the optimal timing for executing maintenance work and capital investments throughout the asset lifecycle. In carrying out this responsibility, Hydro One strives to ensure that it delivers, and can continue to deliver over the long-term, a level of transmission service that is responsive to identified customer needs and preferences, as well as operational needs, while managing risks and mitigating rate impacts.

The Asset Management process encompasses the initial stages of Hydro One's Capital Planning Process. During this process, Hydro One undertakes extensive and detailed technical reviews of its assets to identify a set of investment candidates. Investment candidates are potential programs and projects that are put forth for further consideration during the Investment Planning process, which is discussed in the next section.

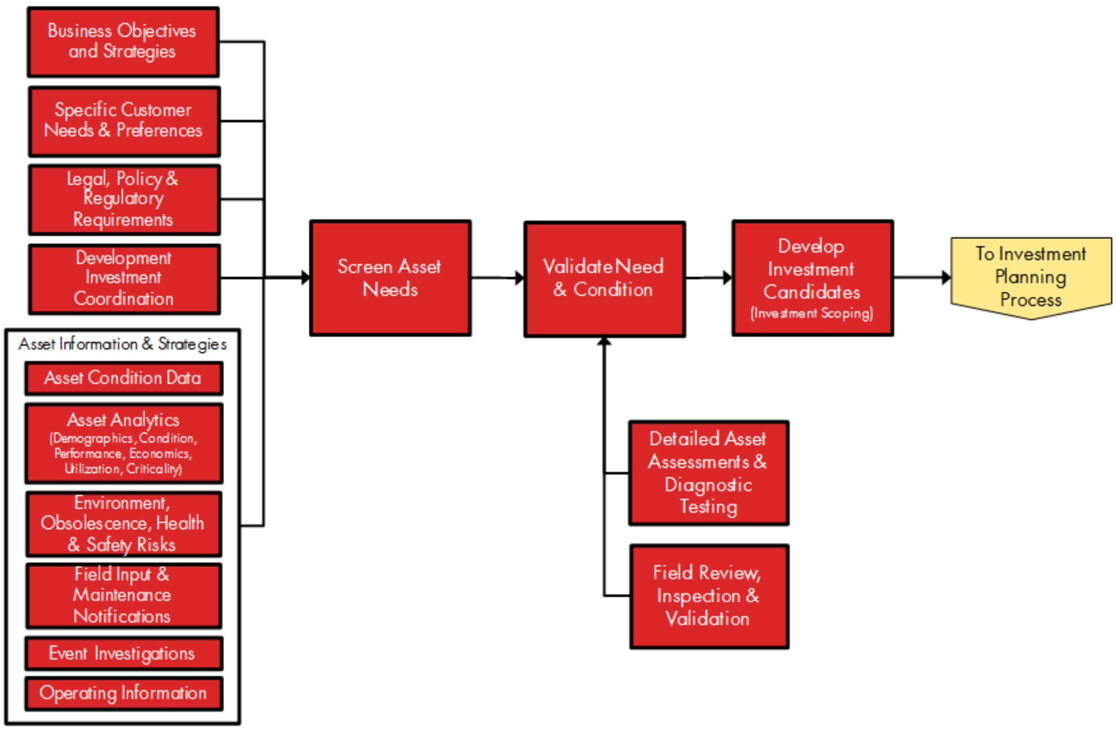


Figure 9 – Hydro One's Capital Planning Process – Asset Risk Assessment

Hydro One's Asset Management process starts with a thorough and systematic review of its transmission asset investment needs, which is reflected in Figure 9 – Hydro One's Capital Planning Process – Asset Risk Assessment. The needs assessment identifies and evaluates individual asset needs that drive the development of candidate investments and includes the collection of data which enables risk scoring to support prioritization and optimization of work undertaken later in the Investment Planning Process. The needs assessment considers (i) asset needs, (ii) customer needs and preferences, (iii) system needs (including those identified through participation in regional planning), and (iv) other external influences. The needs assessment also identifies potential hazards, vulnerabilities, threats or other risk sources that could present obstacles to achieving Hydro One's business objectives.

Hydro One carries out a continuous asset risk assessment ("ARA") process to determine individual asset needs which rely on asset condition data, engineering analysis and other information including the input of experienced planning professionals. An asset analytics system enables Hydro One planners to review aggregated information from various enterprise reporting systems. This drives efficient and effective planning decisions by ensuring a consistent view of asset information for all planners. The information contained within the asset analytics system includes condition information driven by deficiency and preventative maintenance reports, demographic information (including make, model, type and criticality to the transmission system), performance data based on equipment outages, utilization information, and economics. The asset analytics system combines information from various Hydro One databases to provide a common understanding of asset health and aids Hydro One planners in identifying asset risk and optimizing asset lifecycles. Hydro One's planners also take into account additional factors such as load forecasts, equipment ratings, operating restrictions, security incidents, environmental risks and requirements, compliance obligations, equipment defects, obsolescence, and health and safety considerations to ensure capital expenditures target the most appropriate mix of assets.

The ARA process is primarily concerned with the major equipment groups that directly affect system reliability, namely transformers, conductors, breakers and protection and control systems and evaluates them on the following six risk factors:

- Condition - Risk related to the increased probability of failure that assets experience when their condition degrades over time.
- Demographics - Risk related to the increased probability of failure exhibited by assets of a particular make, manufacturer, and/or vintage.
- Criticality - Represents the impact that the failure of a specific asset would have on the transmission system
- Performance - Risk that reflects the historical performance of an asset, derived from the frequency and duration of outages

- Utilization - Risk that reflects the increased rate of deterioration exhibited by an asset that is highly utilized
- Economics - Risk based on the economic evaluation of the ongoing costs associated with the operation of an asset

When assessing individual asset needs, Hydro One's Planners engage in a process of grouping identified needs into logical, functional and geographic groups. For example, a customer need for increased capacity and an asset need to replace transmission station equipment, such as a transformer or switchgear, might be grouped together if the same transmission station is involved. Through this process, diverse individual needs are brought together to form potential projects or programs that may be brought forward as candidate investments. These groupings of potential candidate investments are then scoped and defined based on identified asset needs, customer feedback and other inputs. Following this, Hydro One undertakes a further validation process, described below, to confirm that the need for the project or program is still there, has not evolved and will not be addressed by other means.

As part of investment development, on-site assessments are conducted to ensure site-specific factors such as the physical design, clearances, constructability and safety options requiring geographic flexibility, etc. are considered. During these on-site assessments, planners and field personnel validate and confirm asset condition and related information identified through enterprise reporting systems and asset analytics. Planners will also speak directly with Hydro One personnel who are involved in the day-to-day management and maintenance of the equipment in order to get additional insights into deficiencies and asset needs.

For high-value assets, such as transformers, Hydro One's subject matter experts perform a thorough analysis and advise on issues such as equipment obsolescence, manufacturer support and conduct "repair vs. replace" evaluations. All transformer replacements require review by subject matter experts who prepare Transformer Assessment Reports that are used to validate investment decisions.

These steps inform the development of a set of potential candidate investments. Hydro One's capital investment plans and potential candidate investments are then reviewed with internal stakeholders, such as the company's Customer Service and Transmission and Stations work delivery functions, as well as affected customers. Through this review process, Hydro One ensures that identified customer needs and preferences have been considered and used to inform the development of investment plans and specific candidate investments. Where more than one feasible alternative has been identified for meeting the identified need, a financial analysis (i.e. Net Present Value) is conducted to assist in determining the preferred alternative to put forward as a candidate investment.

The result of the aforementioned ARA process is that a portfolio of specific candidate investments is submitted for further consideration through the Investment Planning process. In that process, specific investments are prioritized to align with intended outcomes based on corporate priorities and strategic objectives, regulatory requirements, investment risks and identified constraints. Before describing the Investment Planning process, the following sections highlight some of the characteristics of asset management relating specifically to each of the main classes of transmission assets – stations and lines.

Stations Asset Management

As noted, Hydro One's transmission system includes 294 stations. Prior to 2014, Hydro One's approach to station asset management was asset-specific. Separate programs were used to consider, plan for and implement replacements for particular asset types (i.e. transformers, breakers and switches) across the province. In 2014, Hydro One transitioned to an integrated approach to station asset management to enable successful delivery of the work program in an efficient manner that minimizes customer impact by requiring fewer planned outages, and optimizing design, execution and operating efficiency. The integrated approach enables work that is required at a particular station to be bundled together and executed at once. Integration of station work and the timing for this work is oriented around key station assets (i.e. transformers, breakers, switches and protection and control equipment).

This station-focused approach addresses infrastructure that is aging and in poor condition, and integrates OM&A and capital programs across multiple disciplines. Hydro One has established a recurring 7-10 year assessment cycle that enables all necessary renewal work to be performed at each of the 294 transmission stations during the cycle. This ensures that asset needs at all stations are reviewed on a recurring basis, which may or may not result in the need for investment after applying the ARA process. By developing and implementing integrated investments for each station, this approach enables Hydro One to efficiently use outages and to minimize the total number of outages required to complete necessary renewal work. The candidate investments identified through the Asset Management process include station-specific packages of work that have been developed in accordance with the established assessment cycle.

Lines Asset Management

Hydro One's approach to asset management for its transmission line assets is shaped by the nature of the specific line assets and their typical service lives. In particular, transmission conductors have an expected service life of 90 years. When a conductor fails or based on its condition, as confirmed by testing, has been determined to have reached end of life, replacement is the only solution. When the conductor needs replacement, this creates a rare opportunity in the asset lifecycle for Hydro One to implement a full line refurbishment of the relevant segment in order to bring the associated assets to a condition that is as close to new as possible. This includes poles, parts of steel structures, foundations and the conductors. Upon completion of a full line refurbishment, the line will be ready to return to service for another 90 years. Other transmission line components do not last this long and are therefore the subject of separate, recurring, asset replacement programs. Such programs are in place for assets such as wood poles, insulators, shield wire, aviation lighting and U-bolts. Program budgets are established through the investment planning process and are typically based on unit costs and the numbers of units that require replacement in a given year. Regardless of the type of transmission line asset, Hydro One's approach to Asset Management is condition-driven such that assets are not replaced unless their condition warrants it.

Investment Planning

Since the EB-2016-0160 proceeding, Hydro One has implemented several changes that address investment planning process concerns raised by intervenors and the OEB. These are summarized in Table 1 above and elaborated on as follows.

In response to concerns raised during the EB-2016-0160 proceeding, Hydro One has implemented an improved eight-step investment planning process. Key improvements to the investment planning process include:

- Consistent scoring for safety, reliability and environmental risk mitigation based on new standardized frameworks;
- Clear definitions of risk impacts to enable consistent scoring across investment types, and calibration sessions to ensure standardized scoring practices; and

Challenge sessions, which are facilitated sessions held with a broad set of stakeholders to (i) review the prioritized portfolio, (ii) confirm non-risk considerations including productivity, (iii) discuss investments on the margin, and (iv) make trade-offs

This process is designed to provide a consistent and common understanding and prioritization and optimization of risk to cost effectively deliver the highest value for Hydro One and its customers. This allows candidate investments to be consistently assessed and prioritized based on level of risk mitigated, cost and value delivered on achieving business objectives.

The process generates an annual budget for work program Operations, Maintenance and Administration ("OM&A") and capital investments, and a six-year planning forecast that allows Hydro One to meet the OEB's filing requirements for a consolidated five-year capital plan.

In summary, the investment planning process consists of the following steps:

1. Investment Planning Context: Hydro One draws on multiple sources of input in the development and prioritization and optimization of the investment plan consistent with Hydro One's Strategic Business Objectives and the OEB's RRF. The investment plan is guided by: (i) strategic vision, (ii) planning and other relevant economic assumptions, (iii) customer engagement feedback, (iv) delivery of key outcomes, and (v) overall assessment of the needs of Hydro One's assets, customers and other stakeholders;
2. Candidate Investment Development: Through the Asset Management process described above, candidate investments are identified, developed and submitted for inclusion in the investment plan;
3. Investment Assessment and Calibration: Investments are scored for safety, reliability, and environmental risk mitigation using a clear and consistent scale based on risk taxonomies. Special, non-risk considerations are also flagged (e.g. Strategic, compliance, customer needs and preferences). Once candidate investments have been scored and flagged, the scores are reviewed in facilitated discussions among investment owners in calibration sessions.
4. Prioritization and Optimization: The results of the risk assessment are translated into risk scores, which are used to generate an initial prioritization and optimization of investments. Following the initial prioritization and optimization, facilitated challenge sessions are held with a broad set of stakeholders to (i) review the prioritized portfolio, (ii) confirm non-risk considerations including productivity, (iii) discuss investments on the margin, and (iv) make trade-offs,

5. Enterprise Engagement: Executing lines of business review the investment plan for operational/execution feasibility, strategic alignment and to challenge investment needs and assumptions;
6. Develop Final Plan: Final decisions are made to arrive at a final version of the investment plan and its outcomes against strategic, customer, and risk considerations;
7. Review and Approval: The investment plan and associated outcomes are reviewed and approved by VPs, the Executive Leadership Team, and the Hydro One Board; and
8. Execution and Performance Monitoring: The execution of the plan is monitored to ensure it is delivered as efficiently as possible.

The Investment Planning process is described in greater detail in Section 2.1 of this TSP.

1.1.5.7 (5.2.1 A) CAPITAL EXPENDITURE PLAN

Based on Hydro One's assessment of its transmission system, a significant portion of its assets have deteriorated to the point where they pose a risk to achieving business objectives for safety, reliability, environment and the customer. Therefore, over the planning period, Hydro One plans to spend approximately $6.6 billion in capital; representing a compound annual growth of 3.5% over five years, to maintain transmission reliability performance, address customer needs and preferences, and mitigate asset and operational risks. This includes delivering $590 million of capital productivity savings improvements (related to the work program) through information technology, procurement, and process efficiency improvements in executing the work.

Hydro One's capital expenditure forecast is $1.2 billion for 2020, increasing to $1.4 billion in 2024. These investments, reflected in Hydro One's TSP, are grouped into four categories: System Access, System Renewal, System Service, and General Plant. Approximately 83% of Hydro One's transmission capital plan is focused on System

Renewal investments. Tables 5 and 6 summarize the capital investment plan based on these four investment categories along with the Progressive Productivity Placeholder savings and Directive Adjustment that are applied as a reduction to the capital expenditures that are sought for rate recovery. Progressive Productivity Placeholder savings are explained further below.

Table 5 – 2020 – 2024 Capital Spending Forecast ($ Million)

Category	Forecast (Planned $M)				
	2020	**2021**	**2022**	**2023**	**2024**
System Access	24.8	11.3	11.7	12.7	4.1
System Renewal	865.2	1,103.1	1,172.8	1,177.4	1,193.8
System Service	204.1	148.2	151.8	174.3	204.2
General Plant	115.4	94.4	94.7	83.6	58.9
Progressive Productivity Placeholder	(17.0)	(39.0)	(61.0)	(78.0)	(91.0)
Directive Adjustment[14]	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)
Total	**1,192.2**	**1,317.7**	**1,369.6**	**1,369.6**	**1,369.6**
System OM&A[15, 16]	**375.8**	*	*	**N/A**	**N/A**

Table 6 – 2020 – 2024 Capital Spending Forecast (% by Category)

Category	2020	2021	2022	2023	2024
System Access	2.1%	0.9%	0.9%	0.9%	0.3%
System Renewal	72.6%	83.7%	85.6%	85.9%	87.1%
System Service	17.1%	11.2%	11.1%	12.7%	14.9%
General Plant	9.7%	7.2%	6.9%	6.1%	4.3%
Progressive Productivity Placeholder	-1.4%	-3.0%	-4.5%	-5.7%	-6.6%
Directive Adjustment	0.0%	0.0%	0.0%	0.0%	0.0%

Investment Summary Documents ("ISD") detailing the specifics for each material investment with spending greater than $3M in any one year are listed in Section 3.3. An

[14] The Directive Adjustment reflects the impact of the directive issued by Ontario's Management Board of Cabinet on February 21, 2019 and the associated compensation framework they approved on March 7, 2019. Refer to Exhibit F, Tab 4, Schedule 1 for further details.
[15] System OM&A includes Operations, Maintenance and Administration expenses. System OM&A for 2021 to 2022 is determined based on the escalation factor identified in Exhibit A, Tab 4, Schedule 1
[16] Includes the Directive Adjustment described in Exhibit F, Tab 1, Schedule 1.

overview of the main factors driving the investments in each of these categories is set out below.

System Renewal

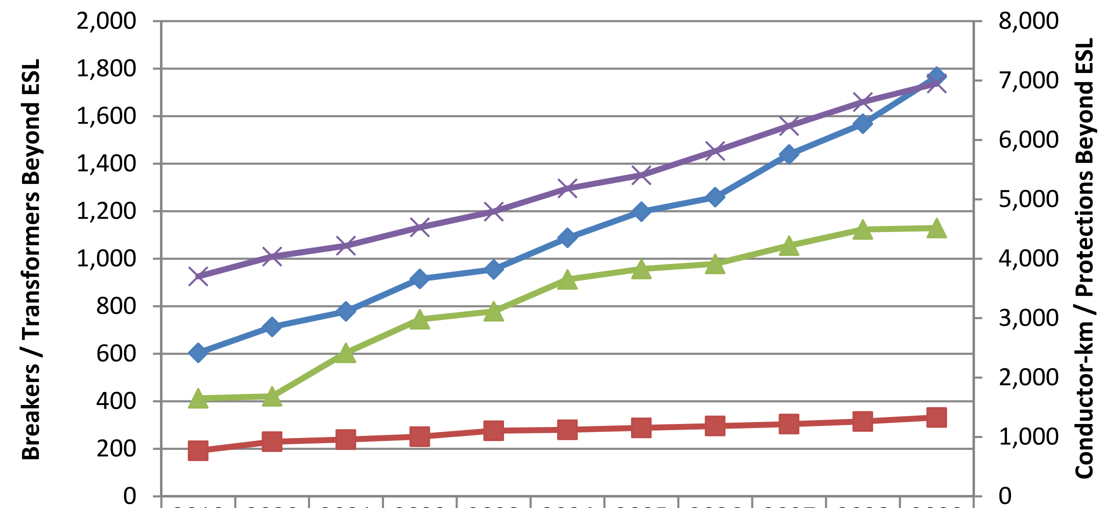
Hydro One's TSP reflects the need for continued station renewal investments at a cost of $3.5 billion, or approximately 53% of the total planned capital expenditures over the planning period, to address deteriorated station assets including transformers, circuit breakers, protection, control and telecom equipment. These replacements are expected to approximately maintain the proportion of transformers on the system that are beyond their expected service life at 26%, approximately maintain the proportion of protection systems operating beyond their expected service life at 28% and maintain the number of breakers that are beyond their expected service life at 12%. This includes the replacement of 72% of the air-blast circuit breakers (ABCBs) at a cost of $594M. ABCBs are about 10 times more expensive to maintain and about 4 times less reliable than their equivalent SF6 circuit breakers.

The TSP also delivers an increased emphasis on line renewal investments at a cost of approximately $2.0 billion to refurbish and replace end of life transmission lines, underground cables, insulators, and wood poles while continuing with tower coating of steel structures to extend their useful life, but at a reduced pacing consistent with prior direction from the OEB. While the planned rate of refurbishment does not keep pace with the overhead lines demographics, the risk is managed through the use of detailed conductor assessments to identify poor condition conductors, informing the line refurbishment program. Lines are candidates for conductor condition assessment starting at 50 years of age.

In developing the TSP, Hydro One recognized that execution of the plan will take place in the context of the broader Ontario power system. In determining the timing and pacing of its investments, Hydro One considered both its own ability to execute capital and

OM&A work efficiently and its ability to secure planned outage time to minimize impacts on customers and other stakeholders in Ontario. As a result, it has planned the pace of renewal work so that certain critical work to reduce risk on the system could be completed in the next five years to ensure that transmission assets are in service and not subject to increased outage constraints resulting from increased failures or additional maintenance that would make the work more difficult to complete.

These investments are required to address the significant demographic pressure that Hydro One is experiencing for some key asset classes. Figure 10 shows the forecasted cumulative number of assets that will exceed their expected service life during the 2019 to 2029 period in the absence of any planned or unplanned replacements. Over this period, the number of assets that are beyond the expected service life in these asset classes would increase by 1.8 to 3.6 times current levels. This rapid and growing shift poses inherent operating and resourcing risks that Hydro One is planning for by proactively and strategically pacing its investments in order to limit pressure on both OM&A and capital costs, while providing the level of service and reliability that customers expect.



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Breakers	604	713	778	915	955	1,088	1,198	1,259	1,439	1,568	1,766
Transformers	192	230	239	251	276	280	288	296	304	315	332
Conductor	1,650	1,683	2,416	2,980	3,115	3,653	3,828	3,914	4,221	4,493	4,516
Protections	3,703	4,036	4,220	4,529	4,795	5,184	5,406	5,814	6,236	6,639	6,952

Figure 10 – Number of Assets Beyond End of Service Life Per Year Summary

System Access and System Service

The TSP funds $947 million of System Access and System Service capital that is required over the planning period to provide transmission access and additional capacity for new customer connections and to implement regional development plans that were developed jointly with customers, transmitters, distributors and the IESO. These investments will result in the addition of seven new transformer stations, ten customer-owned stations and 272 circuit km of new or upgraded transmission lines. Major projects include the development work for the North-West Bulk transmission expansion, new transmission switching and lines facilities to support load growth in the Leamington area, transformation and lines at Milton Switching station, and upgrades/expansion in Barrie and Toronto areas.

General Plant

This TSP funds $447 million of general plant capital that is required over the planning period to support day-to-day business and operations activities such as buildings, tools, equipment, rolling stock, as well as information technology hardware and software. This includes investing $189 million in operating infrastructure and control facilities. This amount includes the new Integrated System Operating Centre ("ISOC"), which represents an investment of $45 million over the planning period, as well as an upgrade to Hydro One's Network Management System – used for grid control, and a refresh of Hydro One's integrated voice communication telephony system.

1.1.5.8 (5.2.1 C) SOURCES OF COST SAVINGS

In its Decision and Order in EB-2016-0160, the OEB directed Hydro One to establish firm short and long-term targets for productivity improvements and associated reductions in revenue requirements as a means to drive continuous improvement and improve the company's internal and external benchmarking standings. As a result of its efforts to address those expectations, and to further its commitment to delivering outcomes that are valued by its customers, Hydro One has developed a comprehensive and rigorous process for identifying, developing, implementing, monitoring and measuring productivity initiatives that will reduce costs while maintaining or improving service quality and work outputs. Hydro One's commitment to achieving incremental and continuous productivity improvements is central to the planning and execution of work programs across the company. Within this framework, quantifiable productivity improvements are included in the Business Plan and corporate scorecards with clear accountabilities for delivering the anticipated savings.

Using this approach, Hydro One has identified savings opportunities in Capital and OM&A totaling approximately $704 million over the plan period. All of these savings are net savings with a direct correlation to a budget and/or spending forecast reduction. Underlying these savings are specific productivity initiatives that have been identified, reviewed, approved and made subject to tracking and reporting requirements. Hydro One has identified savings opportunities totalling approximately $704 million over the 2020-2024 TSP period. There are $353 million in capital productivity savings, $114 million in OM&A productivity savings and $237 million in undefined capital savings. This latter category of savings falls within "Progressive Productivity". Progressive Productivity is a further reduction in cost that Hydro One has included in the final Transmission Business Plan in response to concerns that were raised in the OEB's decision in the Prior Proceeding regarding the level of investment. It represents a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned investments in its transmission system without reducing work volumes. Progressive Productivity savings total $286 million over the planning period and are included in the Transmission Business Plan in the form of:

1. $49 million in Progressive Operations (Defined Capital) savings associated with initiatives that have been identified but which have not yet been proven and verified through the productivity governance framework; and
2. $237 million in Progressive Operations (Undefined Capital) savings which are included as placeholder in the Business Plan to be allocated to any future initiatives that have not yet been identified.

Approximately $590 million of the identified savings opportunities are related to Operations (Operations OM&A, Operations Capital, Progressive Operations (Defined Capital) and Progressive Operations (Undefined Capital), approximately $44 million in savings are IT-related (OM&A and Capital) and approximately $70M in savings are related to Corporate Initiatives (OM&A and Capital). Further details can be found in TSP Section 1.6

Hydro One expects to achieve these significant cost savings over the forecast period through good planning and effective execution of the TSP. Hydro One's productivity framework is further described in Section 1.6 and the productivity savings that Hydro

One expects to achieve over the 2020 to 2024 forecast period are summarized in Table 7 below.

Table 7 – Productivity Savings Forecast ($Millions)

$mm	2020	2021	2022	2023	2024	Total
Operations	47	52	53	53	54	259
Progressive Operations (Defined)	6	12	12	10	10	49
Corporate	12	11	9	7	6	45
Capital Total	**$65**	**$74**	**$73**	**$70**	**$70**	**$353**
Operations	9	10	9	9	9	45
Information Technology	6	9	10	10	10	44
Corporate	7	6	5	4	3	25
OM&A Total	**$22**	**$25**	**$23**	**$23**	**$22**	**$114**
Total Defined	**$87**	**$99**	**$97**	**$93**	**$92**	**$468**
Progressive Operations Productivity Placeholder (Undefined Capital)	11	27	49	68	81	237
Grand Total	**$98**	**$126**	**$146**	**$161**	**$173**	**$704**
Progressive Operations (Defined)	6	12	12	10	10	49
Progressive Operations Productivity Placeholder (Undefined)	11	27	49	68	81	237
Progressive Productivity Placeholder	17	39	61	78	91	286

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Witness: Bruno Jesus

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** "Transmission" refers to Chapter 2 of the OEB's Filing Requirements for Electricity Transmission Applications (February 11, 2016).*

1.2 (5.2.2) COORDINATION THROUGH REGIONAL PLANNING

Planning transmission infrastructure with key stakeholders in a regional context promotes transparency and the cost-effective development of electricity infrastructure in Ontario. This is one of the key guiding principles in the Board's Renewed Regulatory Framework ("RRF"), which states that infrastructure planning on a regional basis, between licensed transmitters and distributors, is to be undertaken to ensure that regional issues and requirements are integrated into a utility's planning processes.

Hydro One Transmission is actively involved in the regional planning process and leading the development of Needs Assessments and Regional Infrastructure Plans. This is consistent with Hydro One's business objective of safely delivering a cost effective and reliable supply of electricity to meet its customers' needs.

This Exhibit provides an overview of the regional planning process and associated customer consultation processes used to engage distributors and other customer groups in regional planning activities. This Exhibit also provides a status update on each of the regions, highlighting investments arising from the regional planning, which form part of Hydro One's capital plan. Hydro One's capital plans are described in TSP Section 3.3.

1.2.1 (5.2.2) OVERVIEW OF THE REGIONAL PLANNING PROCESS

As described in the *Planning Process Working Group Report to the Board: The Process for Regional Infrastructure Planning in Ontario* (the "PPWG Report"), planning for the electricity system in Ontario is generally conducted at three levels:

1. Bulk system planning;
2. Regional system planning; and,
3. Distribution system planning.

Regional planning addresses supply and reliability issues at a regional and/or localized level, such as the supply facilities that connect and deliver power to a group of load stations in an area or region. Regional planning generally considers the 115kV and 230kV portions of the power system, that supply various parts of the province but can overlap with bulk system planning and/or distribution system planning at the interface points or where there may be regional resource options or distribution solutions to address the broader local area for the specific region.

Figure 1 illustrates the various phases of the regional planning process, as documented in the PPWG Report. Hydro One adheres to this process and the corresponding requirements under the Transmission System Code and Distribution System Code, as applicable.

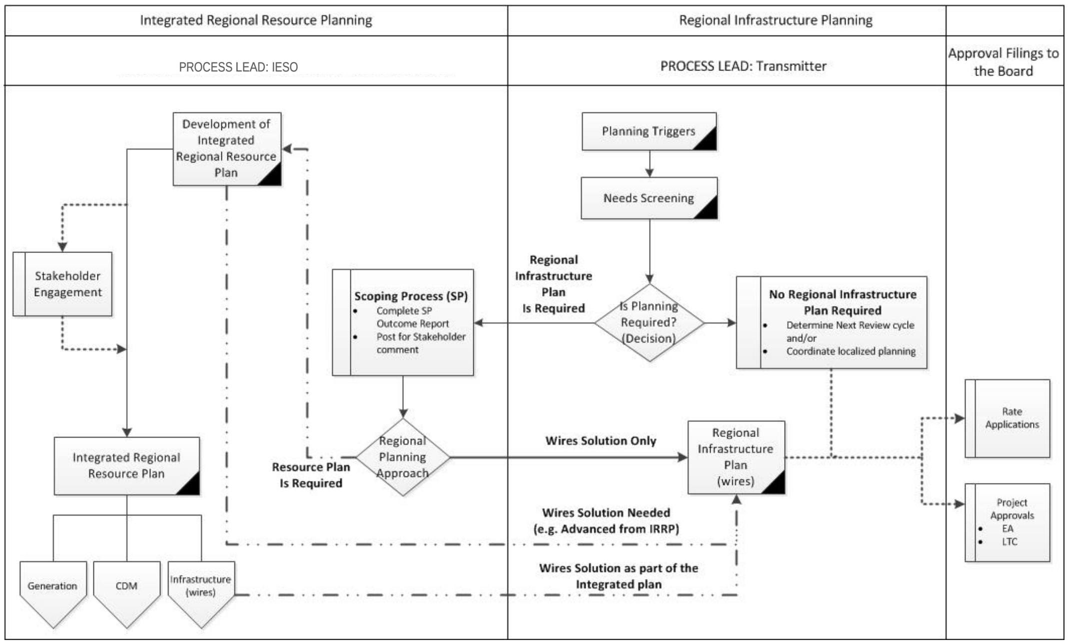

Figure 1: Regional Planning Process

The regional planning process is initiated by a planning trigger. Potential triggers include regularly scheduled Needs Screening by the transmitter, a scheduled review specified in an existing Regional Infrastructure Plan, a Government directive, a significant change to a code or standard, or an emergent need brought forward by the transmitter, distributors, customers, or the Independent Electricity System Operator ("IESO") that must be addressed before the next scheduled review. It is intended that this process is to be repeated for each of the planning regions identified in the PPWG Report every five years; though the process may be more frequent depending upon the emergence of new needs.

Once the regional planning process is initiated by a planning trigger, the process unfolds through the following phases:

- Needs Screening (hereinafter referred to as Needs Assessment ("NA"))[1];

[1] The Needs Screening and Scoping Process phases of regional planning are as described in the PPWG Report; whereas Hydro One refers to these as the Needs Assessment and Scoping Assessment in accordance with the terminology used in the Transmission System Code.

- Scoping Process (hereinafter referred to as Scoping Assessment ("SA"))[1];
- Integrated Regional Resource Plan ("IRRP"); and
- Regional Infrastructure Plan ("RIP").

Needs Assessment

The NA, for a given region, is led by the lead transmitter in the region in consultation with the subject matter experts from the local distributors ("LDCs") and the IESO. These representatives are referred to as a "Study Team"[2]. In this phase, the Study Team identifies merging needs, and undertakes an assessment to determine potential alternatives or solutions to address the needs. During the assessment, information regarding transmission assets reaching the end of their useful life is also identified and assessed for right sizing the equipment. In cases where: (a) the needs are local in nature; (b) further review by subsequent phases in the regional planning process is not required; and (c) the needs can be addressed directly by the transmitter and local distributor(s) or other transmission connected customer(s) through transmission and/or distribution facilities (i.e., a "wires" solution), a local plan is developed. The local plan is ultimately incorporated in the RIP for the region.

Scoping Assessment

In circumstances where the Study Team considers further planning studies and coordination to be necessary, the IESO initiates the SA phase. In this phase the IESO, in collaboration with the lead transmitter and impacted LDCs, reviews the information collected during the NA phase. The IESO also considers information related to potential non-wires alternatives, and determines the most appropriate regional planning approach, i.e., whether an IRRP or a RIP, or both, is required to address the needs in the region or sub-region.

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[2] The *Working Group* as described in the PPWG report is equivalent to *Study Team* as referred to by Hydro One and is the current terminology utilized in the RIP reports.

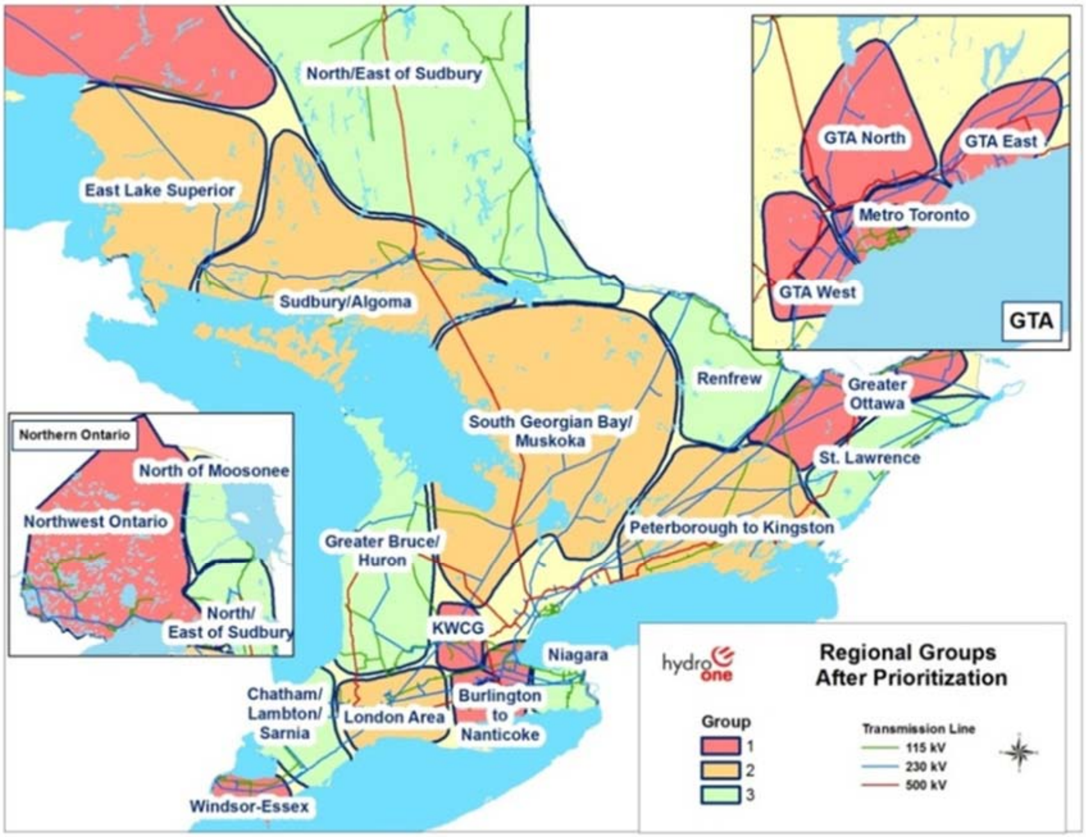
Integrated Regional Resource Plan

The IRRP process involves identifying, evaluating and integrating potential wires and non-wires solutions at the regional or sub-regional level. The IRRP phase generally assesses resource (i.e., generation and/or conservation and demand management) versus wires infrastructure options at a higher level, but with sufficient detail to allow for a comparison of options. If during this phase it is determined that resource options are best suited to meet a need, then those options are further planned by the IESO. However, if wires options are the more appropriate alternative, then those options are further assessed and/or planned as part of the RIP process.

Regional Infrastructure Plan

The RIP process is the final phase of the regional planning process and involves confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle (including end-of-life transmission asset needs that may influence a solution to address broader regional needs); and development of a wires plan to address the needs. This phase is led and coordinated by the transmitter, and the deliverable from this phase is a comprehensive report setting out a wires plan from a regional planning perspective. The wires plan may include distribution investments or options affecting regional needs for optimal outcomes. The recommendations related to transmission and distribution wires planning stemming from the NA, SA, and IRRP are part of the RIP report for the region. The status and corresponding documents from each phase are published on the Hydro One and/or the IESO regional planning websites.

As outlined in Figure 2, there have been 21 electrical regions defined for the purposes of implementing regional planning in Ontario. Each of the 21 regions has been assigned to one of the three regional planning groups in order to prioritize and efficiently manage the regional planning process. Hydro One Transmission is the lead transmitter in all regions, except East Lake Superior and North of Moosonee. The first full cycle of the regional planning for all three groups, which took place over a period of approximately four years, was completed in August 2017 and the second cycle is now in progress commencing with Group 1.



Group 1	Group 2	Group 3
1. Burlington to Nanticoke 2. Greater Ottawa 3. GTA East (1) 4. GTA North 5. GTA West 6. KWCG (2) 7. Metro Toronto 8. Northwest Ontario 9. Windsor-Essex	1. East Lake Superior (3) 2. London Area 3. Peterborough to Kingston 4. South Georgian Bay/Muskoka 5. Sudbury/Algoma	1. Chatham/Lambton/Sarnia 2. Greater Bruce/Huron 3. Niagara 4. North of Moosonee (3) 5. North/East of Sudbury 6. Renfrew 7. St. Lawrence

Notes: *(1) Subsequent to the PPWG Report, GTA East was moved from Group 2 to Group 1*
(2)"KWCG" stands for Kitchener-Waterloo-Cambridge-Guelph
(3) Hydro One Transmission is not the lead transmitter in this region

Figure 2: Regional Planning Regions

1.2.2 (5.2.2 A) REGIONAL PLANNING CONSULTATIONS

As part of the regional planning process, Hydro One undertakes extensive consultation with the LDCs and the IESO to identify needs and develop plans as envisioned by the Board in its RRF. Hydro One also reaches out to its large transmission-connected customers to obtain and update their future plans and electricity load forecasts.

Study Teams have been established in all of the 19 regions across the province, where Hydro One Transmission is the lead transmitter, in order to undertake regional planning. Approximately 70 LDCs along with the IESO participated during the first cycle and continue to be active in the second cycle of the regional planning process. In the Northwest Ontario region, the Study Team led by the IESO also sought input from other stakeholder groups such as: Northwestern Ontario Municipal Association, Common Voice, Ontario Mining Association and municipalities. This unique approach was required due to the vast geographic area, uncertainties related to changing resources and industrial/mining load and challenges not normally seen in other parts of the province.

At each phase of the regional planning process, and for each of the regions, Hydro One has undertaken a combination of the following consultation activities to ensure the involvement and engagement of Study Team members:

1. **Pre-meeting Conference Calls/Webinars:** At the beginning of each phase, LDCs and the IESO are notified in advance of upcoming regional planning activities and are provided an overview of the process.

2. **Kick-off Meetings/Conference Calls/Webinars:** Kick-off meetings with the Study Team are organized to initiate each of the phases of the regional planning process and provide templates for the collection of information/data.

3. **Additional Face to Face Meetings/Conference Calls/Webinars:** The Study Team meets on a regular basis to discuss planning matters, such as: assessment methodology, customer needs, and regional needs and timing before recommending a preferred solution.

In addition to the Study Team members, other customers and stakeholders, such as local municipalities, indigenous communities, business groups, citizen groups, consumers and environmental and conservation groups are contacted and have an opportunity to provide input as part of the IESO-led engagement during the SA and IRRP phases. If continued community input and broader engagement is needed for the regional planning, then a Local Advisory Committee ("LAC") made up of representatives from public and various interested customer and stakeholder groups is formed. In areas where there are a large number of First Nations communities, a First Nations local advisory committee may also be established and representatives from this committee would then be appointed as members of the regional LAC.

The LAC is an advisory body and a forum for communities to provide their input and stay informed about regional planning activities within their region. As an advisory body, the LAC members represent communities and bring forward their interests within the study area and provide insight into their values and perspectives. The LAC input is amongst many inputs that are considered by the Study Team, including information on local priorities (such as municipal or community energy plans), when developing options identified in the plan and ideas on the design of community engagement strategies.

Currently, there are ten active LACs that have been formed to engage communities in the regional planning process, as indicated below:

- Three in the Northwest Ontario region to represent three of the sub-regions: Greenstone-Marathon, City of Thunder Bay, and West of Thunder Bay;

- Two in the South Georgian Bay / Muskoka region to represent the two sub-regions: Parry Sound / Muskoka, and Barrie / Innisfil;
- One in the GTA North region to represent the York sub-region; and
- Four to represent the following four regions: GTA East, Greater Ottawa, Metro Toronto, and Windsor-Essex.

Hydro One also undertakes a broader and comprehensive engagement with the public and other stakeholders at the project development level. All major transmission projects go through the environmental assessment process in accordance with the *Ontario Environmental Assessment Act* and/or the leave to construct approval process in accordance with Section 92 of the *Ontario Energy Board Act*. Each of these processes requires extensive public and stakeholder consultation on projects through such methods as meetings, presentations, public information centres, notices and newspaper advertisements.

In addition to the publication of regional planning reports on Hydro One's website, these consultations ensure transparency in regional planning activities that may influence stakeholders' local plans (such as municipal planning or the development of community energy plans) and they demonstrate Hydro One's responsiveness to public policy and commitment to being a vital partner in the continued economic success of the province.

For specific information on the participants involved in the planning process for particular regions, please refer to the regional planning reports filed as Attachments to this Exhibit or to Hydro One's Regional Planning website, noted below.

https://www.hydroone.com/about/corporate-information/regional-plans

1.2.3 (5.2.2 B) REGIONAL PLANNING OUTCOMES AND STATUS UPDATE

As the lead transmitter, Hydro One Transmission leads the NA and RIP phases of the regional planning process, and actively participates in the SA and IRRP phases led by the IESO.

Hydro One is required, by Section 3C.3.3 of the Transmission System Code, to submit a report to the Board annually on the status of the regional planning activities for all regions. Hydro One filed its 2018 Status Report with the Board on November 1, 2018.[3] As explained in the 2018 Status Report, Hydro One continues to make progress on the second cycle of the regional planning process; including several enhancements that will be reflected in the RIP reports. Table 1 below provides a summary of the current status for each region and sub-region showing the planning phases that are underway or completed. The Sections that follow provide further descriptions of the regional planning activities and investment recommendations scheduled for each of the regions and sub-regions over the 2020 to 2024 period for which Hydro One is the lead transmitter. A letter from the IESO on the overall regional planning status is presented in Attachment 1.

Hydro One is also required by Section 3C.2.2 of the Transmission System Code to provide Planning Status Letters to licensed distributors and transmitters confirming the status of regional planning for a region, suitable for the purpose of supporting an application proposed to be filed with the Board by the distributor or requesting transmitter. In addition to the Planning Status Letters outlined in Appendix B of the 2018 Status Report, Hydro One has recently provided a Planning Status Letter to Kitchener-Wilmot Hydro Inc., Algoma Power Inc., and Alectra Utilities Corporation.

[3] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/Documents/HONI_RegionalPlanningStatusReport_20181101.pdf

Table 1: Regional Planning Status Summary

Group	Region	Sub-region	1st Cycle (2013-2017)				2nd Cycle (2017->)		
			NA	**SA**	**IRRP**	**RIP**	**NA**	**SA**	**IRRP**
1	**Burlington to Nanticoke**	Brant	May, 2014	Sep, 2014	Apr, 2015	Feb, 2017	May, 2017	Aug 2017	Feb 2019 *(RIP now in progress)*
		Bronte			Jun, 2016				
		Greater Hamilton			*Not Required*				
		Caledonia-Norfolk		*Not Required*	*Not Required*				
	Greater Ottawa	Ottawa	Jul, 2014	Nov, 2014	Apr, 2015	Dec, 2015	Jun, 2018	Sept, 2018	*In Progress*
		Outer Ottawa		*Not Required*	*Not Required*				
	GTA East	Pickering-Ajax-Whitby	Aug, 2014	Sep, 2014	Jun, 2016	Jan, 2017	Q3 2019		
		Oshawa-Clarington			*Not Required*				
	GTA North	York	Jun, 2014	*Note1*	Apr, 2015	Feb, 2016	Mar, 2018	Aug, 2018	*In Progress*
		Western		*Not Required*	*Not Required*				
	GTA West	Northwestern	May, 2014	Sep, 2014	Apr, 2015	Jan, 2016	Q2 2019		
		Southern			*Not Required*				
	Kitchener-Waterloo-Cambridge-Guelph		*Note1*		Apr, 2015	Dec, 2015	Dec, 2018	Apr, 2019	*In Progress*
	Metro Toronto	Central Downtown	Jun, 2014	*Note1*	Apr, 2015	Jan, 2016	Oct, 2017	Feb, 2018	*In Progress*
		Northern		*Not Required*	*Not Required*				
	Northwest Ontario	North of Dryden	Note1	Jan, 2015	Jan, 2015	Jun, 2017	Q2 2019		
		Greenstone-Marathon			Jun, 2016				
		Thunder Bay			Dec, 2016				
		West of Thunder Bay			Jul, 2016				
	Windsor-Essex		*Note1*		Apr, 2015	Dec, 2015	Oct, 2017	Mar, 2018	*In Progress*
2	**East Lake Superior**		*Hydro One Transmission is not the lead transmitter in this region. Status to be provided by lead transmitter.*						
	London Area	Greater London	Apr, 2015	Aug, 2015	Jan, 2017	Aug, 2017	Group 2 expected to commence 2nd cycle in 2019.		
		Alymer-Tillsonburg			*Not Required*				
		Strathroy			*Not Required*				
		Woodstock			*Not Required*				
		St. Thomas			*Not Required*				
	Peterborough to Kingston		Feb, 2015	*Not Required*	*Not Required*	Jul, 2016			
	South Georgian Bay/Muskoka	Barrie/Innisfil	Mar, 2015	Jun, 2015	Dec, 2015	Aug, 2017			
		Parry Sound/Muskoka			Dec, 2015				
	Sudbury/Algoma		Mar, 2015	*Not Required*	*Not Required*	Jun, 2016			
3	**North of Moosonee**		*Hydro One Transmission is not the lead transmitter in this region. Status to be provided by lead transmitter.*						
	Chatham/Lambton/Sarnia		Jun, 2016	*Not Required*	*Not Required*	Aug, 2017	Group 3 expected to commence 2nd cycle in 2020.		
	Greater Bruce/Huron		May, 2016	*Not Required*	*Not Required*	Aug, 2017			
	Niagara		Apr, 2016	*Not Required*	*Not Required*	Mar, 2017			
	North/East of Sudbury		Apr, 2016	*Not Required*	*Not Required*	Apr, 2017			
	Renfrew		Mar, 2016	*Not Required*	*Not Required*	Jul, 2016			
	St. Lawrence		Apr, 2016	*Not Required*	*Not Required*	Jul, 2016			

Note 1: The planning activity in the region was already in progress prior to the commencement of the regional planning process; hence the NA/SA was deemed to be already completed by the Study Team.

The Study Teams in the various regions, with input from relevant stakeholders, have recommended more than 60 projects related to transmission investments through the first cycle of regional planning process; with additional needs being identified in the second cycle. The scope and details of these projects are discussed in the corresponding regional planning reports. The specific information on the status of the regional planning process and investments arising from the recommendations of the Study Team that form part of Hydro One's capital plans over the 2020 to 2024 period are highlighted below by each Region Group.

Regions in Group 1

There are nine regions identified in Group 1. Hydro One Transmission is the lead transmitter for all regions in this group. The first cycle of regional planning process has been completed and the second cycle has commenced in six of the nine regions.

Burlington to Nanticoke

The Burlington to Nanticoke region is comprised of four sub-regions: **Brant, Bronte, Greater Hamilton,** and **Caledonia-Norfolk**. The participants in the region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Alectra Inc. (formerly Horizon Utilities Corp.)
- Brantford Power Inc.
- Burlington Hydro Electric Inc.
- Energy + Inc.
- Hydro One Networks Inc. (Distribution)
- Oakville Hydro Electricity Distribution Inc.

The first cycle RIP for this region was completed in February 2017 and is presented in Attachment 2 of this Exhibit. In addition to advancing the work from the IRRP presented in Hydro One's previous rate application (EB-2016-0160), the RIP also identified additional needs related to end-of-life transmission assets in the Hamilton area. The plans to address these end-of-life needs have been developed by Hydro One and confirmed by the region's LDC's.

As documented in Hydro One's previous rate application, the project to install 115kV switching facilities at Brant TS *(Project D09 in EB-2016-0160)* was identified as one of the transmission infrastructure investments required for the region. This investment along with the following system renewal investments, recommended in the RIP are continuing to be developed and are expected for in-service in 2019.

- **Beach TS:** Transformer (T3/T4) Replacement; and
- **Bronte TS:** Transformer (T5/T6) and DESN Refurbishment.

In response to the remaining RIP recommendations, this TSP contemplates the following investments over the 2020 to 2024 period:

- **Beach TS:** Auto-Transformer (T7/T8) Replacement and DESN Switchgear (Part of SR-03);
- **Birmingham TS:** MV Metalclad Switchgear Refurbishment (Part of SR-05);
- **Dundas TS:** MV Switchyard Refurbishment (Part of SR-06);
- **Dundas TS #2:** Two New Feeder Positions (SA Other Projects);
- **Elgin TS:** Transformer and DESN Reconfiguration (Part of SR-02);
- **Gage TS:** Transformer and DESN Reconfiguration (Part of SR-02);
- **Kenilworth TS:** Transformer and DESN Reconfiguration (Part of SR-02);
- **Lake TS:** LV Switchyard Refurbishment (Part of SR-06);
- **Newton TS:** Station Refurbishment (Part of SR-05);
- **115kV B3/B4 Transmission Line:** Refurbish line sections from Horning Mountain Junction to Glanford Junction (Part of SR-19); and

- **115kV B7/B8 Transmission Line:** Refurbish line sections from Burlington TS to Nelson Junction (SR Other Projects).

The second cycle NA report[4] for this region was completed in May 2017. The NA continues to reaffirm the needs identified in the first cycle RIP and has identified the need for the following additional system renewal investments over the 2020 to 2024 period:

- **Burlington TS:** LV Switchyard Refurbishment (Part of SR-06); and
- **Norfolk TS:** LV Switchyard Refurbishment (Part of SR-06).

The second cycle IRRP phase led by the IESO was completed in February 2019; and now the RIP phase led by Hydro One is currently underway.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Greater Ottawa

The Greater Ottawa Region is comprised of two sub-regions: **Ottawa Area** and **Outer Ottawa**. The participants in the region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hydro Hawkesbury Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro Ottawa Limited
- Ottawa River Power Corporation

[4] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/burlingtontonanticoke/Documents/Needs%20Assessment_Burlington%20to%20Nanticoke_May15_2017.pdf

The RIP for this region was completed in December 2015 and was provided in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is provided in Attachment 3 to this Exhibit.

As documented in Hydro One's previous rate application, the RIP identified the following three transmission infrastructure investments that were expected to be completed over the 2017 to 2019 period:

- **Circuit A4K Capacity:** Addition of 115kV tap *(Project D10 in EB-2016-0160);*
- **Lisgar TS:** Transformer Replacement *(Project D16 in EB-2016-0160)*; and
- **Overbrook TS:** Transformer (T1/T2) Replacement.

These investments are either complete or are continuing to be developed for in-service in 2019, with the exception of the Lisgar TS investment that has been deferred after further evaluation of the need. Load growth in the region will be monitored for further reassessment in the next regional planning cycle to determine the need for this project.

In response to the remaining RIP recommendations for this region, this TSP contemplates the following investments over the 2020 to 2024 period:

- **Hawthorne TS:** Transformer (T7/T8) Replacement (Part of SR-05);
- **Hawthorne TS:** Autotransformer (T5/T6) Replacement (SS Other Projects);
- **King Edward TS:** Transformer Replacement (Part of SR-05); and
- **Supply for New Station in Southwest Area** (Project SS-11).

The second cycle NA report[5] for this region was published in June 2018. The NA continues to reaffirm the needs identified in the first cycle RIP and has identified the need for the following additional system renewal investments over the 2020 to 2024 period:

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[5]https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterottawa/Documents/Greater%20Ottawa%20Needs%20Assessment%202018.pdf

- **Arnprior TS:** Transformer (T1/T2) Replacement (Part of SR-02);
- **Longueuil TS:** Transformer (T3/T4) Replacement (Part of SR-05);
- **Slater TS:** Transformer (T1/T2/T3) Replacement (Part of SR-02); and
- **115kV S7M Transmission Line:** Refurbish line sections (SR Other Projects).

The second cycle IRRP phase led by the IESO is currently underway; with the RIP for this region to be initiated and developed upon the completion of this IRRP.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

GTA East

The GTA East Region is comprised of two sub-regions: **Pickering-Ajax-Whitby** and **Oshawa-Clarington**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hydro One Networks Inc. (Distribution)
- Oshawa PUC Networks Inc.
- Veridian Connections Inc.
- Whitby Hydro Electric Corporation

The RIP for this region was completed in January 2017 and is provided in Attachment 4 to this Exhibit. This RIP advances the work from the IRRP documented in Hydro One's previous rate application (EB-2016-0160) with no additional needs or investment plans identified.

As documented in Hydro One's previous rate application, there were two transmission infrastructure investments identified for the region, including:

- Connection of a new station "**Enfield TS**" *(Project D21 in EB-2016-0160)*; and
- Connection of a new station "**Seaton MTS**" *(Project D17 in EB-2016-0160)*.

These investments are continuing to be developed and are expected in-service in the 2019 to 2020 period.

At this time, no further regional planning transmission infrastructure investments are expected over the 2020 to 2024 planning period.

GTA North

The GTA North Region is comprised of two sub-regions: **York** and **Western**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Alectra Inc. (formerly Enersource Hydro Mississauga Inc., Hydro One Brampton Networks Inc. and PowerStream Inc.)
- Hydro One Networks Inc. (Distribution)
- Newmarket-Tay Power Distribution Ltd.
- Toronto Hydro-Electric System Limited ("THESL")

The RIP for this region was completed in February 2016 and was presented in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is included in Attachment 5 to this Exhibit.

As documented in Hydro One's previous rate application, the RIP identified three transmission infrastructure investments over the 2017 to 2018 period. These investments have been completed and placed in-service, including the connection of a new load station "Vaughan #4 MTS"; the installation of breakers and switches at Holland TS; and the installation of two inline switches on the 230kV circuits V71P/V75P at Grainger Junction.

The second cycle NA report[6] for this region was completed in March 2018. The NA has identified the need for the following investments over the 2020 to 2024 period:

- Connection of a new load station "**Markham #5 MTS**" (SA Other Projects); and
- **Woodbridge TS:** Transformer (T5) Replacement (Part of SR-05).

The second cycle IRRP phase led by the IESO is currently underway; with the RIP for this region to be initiated and developed upon the completion of this IRRP.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

GTA West

The GTA West Region is comprised of two sub-regions: **Northwestern** and **Southern**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO

[6] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtanorth/Documents/Needs%20Assessment%20Report%20-%20GTA%20North%20Region.pdf

- Alectra Inc. (formerly Enersource Hydro Mississauga Inc. and Hydro One Brampton Networks Inc.)
- Burlington Hydro Electric Inc.
- Halton Hills Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

The RIP for this region was completed in January 2016 and was presented in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is included in Attachment 6 to this Exhibit.

In response to the RIP recommendations, this TSP contemplates the following investments over the 2020 to 2024 period:

- Connection of a new load station "**Halton TS #2**" (Project SA-03);
- **Milton SS:** Station Expansion and Connect 230kV circuits (Project SS-07); and
- **Reconductor 230kV H29/H30 Transmission Line** (SA Other Projects).

Further details on this investment are provided in TSP Section 3.3.8 Investment Summary Documents.

Kitchener-Waterloo-Cambridge-Guelph ("KWCG")

The KWCG Region includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington counties and associated townships in the area. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO

- Cambridge and North Dumfries Hydro Inc.
- Centre Wellington Hydro
- Guelph Hydro Electric System Inc.
- Halton Hills Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Kitchener-Wilmot Hydro Inc.
- Milton Hydro Distribution Inc.
- Waterloo North Hydro Inc.
- Wellington North Power Inc.

The RIP for this region was completed in December 2015 and was presented in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is included in Attachment 7 to this Exhibit.

As documented in Hydro One's previous rate application, the RIP identified several transmission infrastructure investments to be completed over the 2016 to 2017 period. These investments have been completed and placed in-service, including the investment for the installation of in-line switches on circuits M20D/M21D at Galt Junction.

The second cycle NA report[7] for this region was published in December 2018. The NA has identified the need for the following system renewal investments over the 2020 to 2024 period:

- **Cedar TS:** Transformer (T7/T8) Replacement (Part of SR-05);
- **Detweiler TS:** Autotransformer (T2/T4) Replacement (Part of SR-03);
- **Hanlon TS:** Transformer (T1/T2) Replacement (Part of SR-05); and
- **Preston TS**: Transformer (T3/T4) Replacement (Part of SR-05).

[7] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/kitchenerwaterloocambridgeguelph/Documents/KWCG%20Needs%20Assessment%202018.pdf

The second cycle IRRP phase led by the IESO is currently underway; with the RIP for this region to be initiated and developed upon the completion of this IRRP.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Metro Toronto

The Metro Toronto Region is comprised of two sub-regions: **Central Downtown** and **Northern**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Alectra Inc. (formerly Enersource Hydro Mississauga Inc. and PowerStream Inc.)
- Hydro One Networks Inc. (Distribution)
- THESL
- Veridian Connections Inc.

The RIP for this region was completed in January 2016 and was presented in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is provided in Attachment 8 to this Exhibit.

As documented in Hydro One's previous rate application, the RIP identified several near-term transmission infrastructure investments for the region, including:

- **Horner TS:** Addition of a second transformer station (Project SA-02);
- **Manby TS:** Autotransformer overload protection scheme;
- **Runnymede TS:** Expansion of transformer station and reconductor the 115kV circuits (*Project D19 in EB-2016-0160*); and
- **Southwest GTA Transmission Reinforcement** (Project SS-14).

The investments at Runnymede TS and Manby TS were completed and placed in-service in 2018. The other two investments, along with the connection for Copeland MTS Phase 2, are expected to be in-service over the 2020 to 2024 period.

The second cycle NA report[8] for this region was published in October 2017. The NA continues to reaffirm the needs identified in the first cycle RIP and has identified the need for the following additional system renewal investments over the 2020 to 2024 period:

- **Bermondsey TS:** Transformer (T3/T4) Replacement (Part of SR-05);
- **Bridgman TS:** Transformer (T11-T13) Replacement (Part of SR-05);
- **Charles TS:** Transformer (T3/T4) Replacement (Part of SR-05);
- **Duplex TS:** Transformer (T1/T2) Replacement (Part of SR-05);
- **Fairbank TS:** Transformer (T1-T4) Replacement (Part of SR-02);
- **Fairchild TS:** Transformer (T1/T2) Replacement (Part of SR-05);
- **John TS:** Station Reinvestment (Part of SR-08);
- **Leslie TS:** Transformer (T1) Replacement (Part of SR-05);
- **Main TS:** Transformer (T3/T4) Replacement (Part of SR-05);
- **Manby TS:** Transformer (T7/T9/T12/T13) and 230kV Component Replacement (Part of SR-03);
- **Runnymede TS:** Transformer (T3/T4) Replacement (Part of SR-02);
- **Sheppard TS:** Transformer (T3/T4) Replacement (Part of SR-02);
- **Strachan TS:** Transformer (T12) Replacement (Part of SR-05);
- **115kV C5E/C7E Underground Cables:** Refurbish cable sections from Esplanade TS to Terauley TS (Part of SR-27);
- **115kV H1L/H3L/H6LC/H8LC Transmission Lines**: Refurbish line sections from Leaside Junction to Bloor St. Junction (Part of SR-19); and

[8] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/Needs%20Assessment%20-%20Toronto%20Region%20-%20Final.pdf

- **115kV L9C/L12C Transmission Lines:** Refurbish line sections from Leaside TS to Balfour Junction (SR Other Projects).

The second cycle IRRP phase led by the IESO is currently underway; with the RIP for this region to be initiated and developed upon the completion of this IRRP.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Northwest Ontario

The Northwest Ontario Region is comprised of several sub-regions: **North of Dryden, Greenstone-Marathon, City of Thunder Bay,** and **West of Thunder Bay**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Atikokan Hydro Inc.
- Fort Frances Power Corporation
- Hydro One Networks Inc. (Distribution)
- Kenora Hydro Electric Corporation Ltd.
- Sioux Lookout Hydro Inc.
- Thunder Bay Hydro Electricity Distribution Inc.

The RIP for this region was completed in June 2017 and is presented in Attachment 9 to this Exhibit. This RIP advances the work from the IRRP documented in Hydro One's previous rate application (EB-2016-0160).

In response to the RIP recommendations, this TSP contemplates the following investment over the 2020 to 2024 period:

- Connection to the new 230kV transmission line from Dryden/Ignace area to Pickle Lake (Project SS-02).

Further details on this investment are provided in TSP Section 3.3.8 Investment Summary Documents.

Windsor-Essex

The Windsor-Essex Region is in the southern-most part of Ontario, extending from Chatham southwest to Windsor. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- E.L.K. Energy Inc.
- Entegrus Powerlines Inc.
- EnWin Utilities Ltd.
- Essex Powerlines Corporation
- Hydro One Networks Inc. (Distribution)

The RIP for this region was completed in December 2015 and was presented in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is provided in Attachment 10 to this Exhibit.

As documented in Hydro One's previous rate application, the RIP identified several near-term transmission infrastructure investments for this region, including:

- **Keith TS:** Autotransformer Replacement (Part of SR-03);
- **Keith TS:** Reconfiguration due to the Gordie Howe International Bridge;

- **Kingsville TS:** Transformer Replacement (Part of SR-05); and
- **Supply to Essex County Transmission Reinforcement.**

These investments are either complete and/or continue to be developed for in-service in 2019; with the exception for the second Kingsville TS transformer and the Keith transformer replacements that are planned for in-service over the 2020 to 2024 period.

The second cycle NA report[9] for this region was completed in October 2017. The NA continues to reaffirm the needs identified in the first cycle RIP and has identified the need for the following investments over the 2020 to 2024 period:

- **Malden TS:** Additional feeder positions (SA Other Projects); and
- **Lauzon TS:** Transformer (T6/T8) and Component Replacement (Part of SR-05).

In addition to these investments, the need for transmission reinforcement in the Leamington Area has been highlighted in assessment work undertaken by the IESO in the development of their 2019 Windsor-Essex Integrated Regional Resource Plan. To ensure customer needs are addressed in a timely manner, this TSP contemplates the Leamington Area transmission reinforcement and the building of a second 230/27.6kV DESN (Project SS-13) to address the need.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Regions in Group 2

There are five regions in Group 2 for which the first cycle of the regional planning process has been completed. Hydro One Transmission is the lead transmitter for all regions in this group with the exception of the East Lake Superior region.

[9]https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/windsoressex/Documents/Needs%20Assessment_Windsor-Essex_Final.pdf

London Area

The London Area Region is comprised of five sub-regions: **Greater London, Aylmer-Tillsonburg, Strathroy, Woodstock,** and **St. Thomas**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Entegrus Powerlines Inc.
- Erie Thames Powerlines Corporation
- Hydro One Networks Inc. (Distribution)
- London Hydro Inc.
- St. Thomas Energy Inc.
- Tillsonburg Hydro Inc.

The RIP for this region was completed in August 2017 and is provided in Attachment 11 of this Exhibit. This RIP advances the work from the IRRP documented in Hydro One's previous rate application (EB-2016-0160).

In response to the RIP recommendations, this TSP contemplates the following investments over the 2020 to 2024 period:

- **Aylmer-Tillsonburg Area Transmission Reinforcement** (Project SS-12); and
- **Wonderland TS:** Station Refurbishment (Part of SR-02).

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Peterborough to Kingston

The Peterborough to Kingston Region includes the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, Frontenac County on the East, and Lake Ontario on the South. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hydro One Networks Inc. (Distribution)
- Kingston Hydro
- Peterborough Distribution Inc.
- Veridian Connections Inc.

The RIP for this region was completed in July 2016 and is provided in Attachment 12 of this Exhibit. The RIP identified that the needs for this region were strictly local in nature. Local plans have been developed by Hydro One and the impacted LDCs in the area to balance the Gardiner TS load. In addition, the IESO will assess and develop a plan for contingencies associated with the 115kV circuit (Q6S) and 230kV circuit (P15C) as part of the IESO-led bulk system planning study. At this time, no further regional planning transmission infrastructure investments are contemplated over the 2020 to 2024 planning period.

South Georgian Bay/Muskoka

The South Georgian Bay/Muskoka Region is comprised of two sub-regions: **Barrie/Innisfil** and **Parry Sound/Muskoka**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO

- Alectra Inc. (formerly PowerStream Inc.)
- Hydro One Networks Inc. (Distribution)
- InnPower Corporation
- Orangeville Hydro Ltd.
- Veridian Connections Inc.

The RIP for this region was completed in August 2017 and is provided in Attachment 13 of the Exhibit. This RIP advances the work from the IRRP documented in Hydro One's previous rate application (EB-2016-0160) and interim letter from the IESO to commence work to address equipment approaching end-of-life at Barrie TS.

In response to the RIP recommendations, this TSP contemplates the following investments over the 2020 to 2024 period:

- **Barrie Area Transmission Upgrade** (Project SS-09);
- **Minden TS:** Transformer Replacement, LV Switchyard Rebuild (Part of SR-05);
- **Orangeville TS:** Transformer (T1/T2) Replacement (Part of SR-05); and
- **Parry Sound TS:** Transformer Replacement (Part of SR-05).

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Sudbury/Algoma

The Sudbury/Algoma Region includes the Greater Sudbury Area, Manitoulin Island, and Townships of Verner, Warren, Elliot Lake, Blind River, and Walden. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Greater Sudbury Hydro

- Hydro One Networks Inc. (Distribution)

The RIP for this region was completed in June 2016 and is provided in Attachment 14 of this Exhibit. Local plans have been implemented by Hydro One to address the Manitoulin TS Low Voltage Regulation. Furthermore, the recommendation for a new 230/44kV Station at Hanmer TS identified in the RIP and documented in Hydro One's previous rate application for in-service in 2019 has been deferred after further evaluation of the need and customer consultation. Load growth in the region will be monitored for further reassessment in the next regional planning cycle to determine the need for this project.

At this time, no further regional planning transmission infrastructure investments are contemplated over the 2020 to 2024 planning period.

East Lake Superior

The East Lake Superior region spans the area from Wawa to north of Thessalon. Formerly, Great Lakes Power Transmission LP ("GLPT") was the lead transmitter for this region. GLPT conducted the regional process in late 2014 including representatives from the IESO, Hydro One Networks, Algoma Power Inc., PUC Distribution and Chapleau Public Utility Corporation. Through this process, it was determined that there were no electricity needs in the next ten years requiring regional coordination.

In October 2016, Hydro One Inc. acquired GLPT and is operating the transmission business through a separate subsidiary known as Hydro One Sault Saint Marie ("Hydro One SSM"). As such, the lead transmitter for this region is now Hydro One SSM. This TSP does not contemplate any regional planning transmission infrastructure investments in this region during the 2020 to 2024 planning period.

Regions in Group 3

There are seven regions in Group 3 for which the first cycle of the regional planning process has been completed. Hydro One Transmission is the lead transmitter for all regions in this group with the exception of the North of Moosonee region.

Chatham/Lambton/Sarnia

The Chatham-Lambton-Sarnia Region includes the municipalities of Lambton Shores and Chatham-Kent, as well as associated townships in the area. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Bluewater Power Distribution Corporation
- Entegrus Powerlines Inc.
- Hydro One Networks Inc. (Distribution)

The RIP for this region was completed in August 2017 and is provided in Attachment 15 of this Exhibit. The RIP identified that the needs for this region were strictly local in nature and no transmission infrastructure investment is required. Local plans have been implemented by Hydro One to address a capacity issue at Kent TS. In addition to the local needs, the RIP also identified several system renewal investments for the region. In response to the recommendations made in the RIP report, this TSP contemplates the following investments over the 2020 to 2024 period:

- **St. Andrews TS:** Transformer (T3/T4) Replacement and DESN Refurbishment (Part of SR-02); and
- **Sarnia Scott TS:** Transformer (T5) and component Replacement (Part of SR-03).

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Greater Bruce / Huron

The Greater Bruce/Huron region includes the municipalities of Arran–Elderslie, Brockton, Kincardine, Northern Bruce Peninsula, and South Bruce. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Entegrus Powerlines Inc.
- Erie Thames Powerlines Corporation
- Festival Hydro Inc.
- Goderich Hydro - West Coast Huron Energy Inc.
- Hydro One Networks Inc. (Distribution)
- Wellington North Power Inc.
- Westario Power Inc.

The RIP for this region was completed in August 2017 and is provided in Attachment 16 to this Exhibit. The RIP identified a local need to improve L7S customer delivery point performance. Further assessment work outside the regional planning process is in progress for this local need to identify alternatives and develop mitigation plans. At this time, no further regional planning transmission infrastructure investments are expected over the 2020 to 2024 planning period.

Niagara

The Niagara Region comprises twelve municipalities in the southern end of the Golden Horseshoe. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO

- Alectra Inc. (formerly Horizon Utilities Corp.)
- Canadian Niagara Power Inc.
- Grimsby Power Inc.
- Haldimand County Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Niagara Peninsula Energy Inc.
- Niagara-on-the-Lake Hydro Inc.
- Welland Hydro Electric System Corp.

The RIP for this region was completed in March 2017 and is provided in Attachment 17 to this Exhibit. The RIP identified that the needs for this region were strictly local in nature. Local plans have been implemented by Hydro One to address thermal overloading of the 115kV circuit (Q4N) by upgrading the conductor on a section of Q4N from Beck 1 SS to Portal Junction. At this time, no further regional planning transmission infrastructure investments are contemplated over the 2020 to 2024 planning period.

North/East of Sudbury

The North/East of Sudbury Region is the area roughly bordered by Moosonee to the North, Hearst to the North-West, Ferris to the South, and Kirkland Lake to the East. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hearst Power Ltd.
- Hydro One Networks Inc. (Distribution)
- North Bay Hydro Distribution Ltd.
- Northern Ontario Wires Inc.

The RIP for this region was completed in April 2017 and is provided in Attachment 18 to this Exhibit. The RIP identified that the needs for this region were strictly local in nature. Local plans were developed by Hydro One and the impacted LDCs in the area to address Timmins TS/Kirkland Lake TS voltage regulation issues. At this time, no further regional planning transmission infrastructure investments are contemplated over the 2020 to 2024 planning period.

Renfrew

The Renfrew Region includes all of Renfrew County. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hydro One Networks Inc. (Distribution)
- Ottawa River Power Corporation
- Renfrew Hydro Inc.

The RIP for the region was completed in July 2016 and is provided in Attachment 19 to this Exhibit. The RIP identified that there were no capacity, system reliability or operating needs that required investments over the planning horizon. As such, this TSP does not contemplate any transmission infrastructure investments for this region over the 2020 to 2024 period resulting from the regional planning process.

St. Lawrence

The St. Lawrence Region covers the southeastern part of Ontario bordering the St. Lawrence River. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)

- IESO
- Hydro One Networks Inc. (Distribution)

The RIP for this region was completed in July 2016 and is provided in Attachment 20 to this Exhibit. The RIP identified that there were no capacity, system reliability or operating needs that required investments over the planning horizon. As such, this TSP does not contemplate any transmission infrastructure investment for this region over the 2020 to 2024 period resulting from the regional planning process.

North of Moosonee

Five Nations Energy Inc. ("FNEI") is the lead transmitter for this region and is therefore responsible for the RIP. This TSP does not contemplate any regional planning transmission infrastructure investments in this region.

1.2.4 (5.2.2 B / C) ATTACHMENTS: IESO REGIONAL PLANNING STATUS LETTER AND REGIONAL INFRASTRUCTURE PLAN REPORTS

Attachment 1 – IESO Regional Planning Progress Update Letter to Hydro One
Attachment 2 – RIP Report: Burlington to Nanticoke
Attachment 3 – RIP Report: Greater Ottawa
Attachment 4 – RIP Report: GTA East
Attachment 5 – RIP Report: GTA North
Attachment 6 – RIP Report: GTA West
Attachment 7 – RIP Report: KWCG
Attachment 8 – RIP Report: Metro Toronto
Attachment 9 – RIP Report: Northwest Ontario
Attachment 10 – RIP Report: Windsor-Essex
Attachment 11 – RIP Report: London Area
Attachment 12 – RIP Report: Peterborough to Kingston
Attachment 13 – RIP Report: South Georgian Bay / Muskoka
Attachment 14 – RIP Report: Sudbury / Algoma
Attachment 15 – RIP Report: Chatham / Lambton / Sarnia
Attachment 16 – RIP Report: Greater Bruce / Huron
Attachment 17 – RIP Report: Niagara
Attachment 18 – RIP Report: North/East of Sudbury
Attachment 19 – RIP Report: Renfrew
Attachment 20 – RIP Report: St. Lawrence

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

February 4, 2019

VIA EMAIL

Mr. Ajay Garg
Manager, Regional Transmission Planning
Hydro One Networks Inc.
483 Bay Street
Toronto, ON
M5G 2P5

Dear Mr. Garg:

Re: Independent Electricity System Operator
Regional Planning Progress Update

The Independent Electricity System Operator ("IESO") has been notified by Hydro One Networks Inc. ("Hydro One") of its upcoming 2020-2022 rate application to the Ontario Energy Board ("OEB") and has been requested to provide Hydro One with a regional planning status update for the planning regions in the province. This request includes regional planning areas undergoing either a Needs Assessment ("NA"), Scoping Assessment ("SA") or an Integrated Regional Resource Planning ("IRRP").

Hydro One's request is based on the requirement of section 2.4.2 of the OEB's Chapter 2 Filing Requirements for Electricity Transmission Applications which states:

> *Where regional planning is underway, but a Regional Infrastructure Plan has not yet been completed for the applicable region, the applicant shall submit a letter from the Independent Electricity System Operator ("IESO"), identifying the status of the regional planning process, and the potential impacts on the applicant's investment plans.*

Pursuant to the above referenced filing requirements, the IESO hereby provides the status of regional planning as follows.

The first cycle of regional planning for all 21 regions was completed in Q3, 2017 and the second cycle has started for some of the regions in Group 1. The table below provides the status of the regional plans that are presently underway; regional planning for regions that are not listed in this table have not yet started.

Table 1: Active regions in second round of Regional Planning

Group 1 Regions	Sub-Regions	Status	Expected Completion Date of the Stage that is in Progress
Burlington to Nanticoke	Brant	NA/SA completed. IRRP in progress for the Greater Hamilton sub-region.	Q1 2019
	Bronte		
	Greater Hamilton		
	Caledonia-Norfolk		
Greater Ottawa	Ottawa	NA/SA completed. IRRP in progress for the Outer Ottawa sub-region.	Q3/Q4 2019
	Outer Ottawa		
GTA North	York	NA/SA completed. IRRP in progress for the York sub-region.	Q4 2019
	Western		
GTA West	Northwestern	NA underway.	Q1 2019
	Southern		
KWCG	No sub-regions	NA completed. SA in progress.	Q1 2019
Toronto	No sub-regions	NA/SA completed. IRRP in progress.	Q4 2019
Northwest Ontario	North of Dryden	NA in progress.	Q1 2019
	Greenstone-Marathon		
	Thunder Bay		
	West of Thunder Bay		
Windsor-Essex	No sub-regions	NA/SA completed. IRRP in progress.	Q3 2019

During the second cycle of regional planning, the Regional Planning Study Team is giving greater consideration to assets reaching end of life. More specifically, they are considering opportunities to "right size" equipment, the potential reliability impact of the longer-term outages required to carry out significant replacement projects, and the potential to optimize the system design as part of the scope of the asset replacement. Therefore, while investments would most likely be necessary to address assets reaching end of life, in some cases the specific investment required may depend on the outcome of the regional planning processes that are presently underway.

If you have any questions about the IESO's comments please contact me directly at 905-855-6340 or Devon.Huber@ieso.ca.

Yours truly,

Devon Huber
Senior Manager, Regulatory Affairs

cc: Bob Chow, Director, Transmission Planning, IESO
Ahmed Maria, Director, Transmission Planning, IESO

Burlington to Nanticoke

REGIONAL INFRASTRUCTURE PLAN

February 7, 2017

hydro one

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Prepared and supported by:

Company
Brantford Power Inc.
Burlington Hydro Inc.
Energy + Inc.
Alectra Utilities Corporation (former Horizon Utilities Inc.)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Oakville Hydro
Hydro One Networks Inc. (Lead Transmitter)

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Disclaimer

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH PARTICIPATION AND INPUT FROM THE RIP WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED, DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE BURLINGTON TO NANTICOKE REGION.

The participants of the RIP Working Group included members from the following organizations:

- Brantford Power Inc.
- Burlington Hydro Inc.
- Energy + Inc.
- Alectra Utilities Corporation (former Horizon Utilities Inc.)
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator (IESO)
- Oakville Hydro
- Hydro One Networks Inc. (Lead Transmitter)

In general, the RIP is the final phase of the regional planning process and, in this case, it follows the completion of the Integrated Regional Resource Plans ("IRRP") for Brant Sub-Region and Bronte Sub-Region in March 2015 and June 2016, respectively, and the Burlington to Nanticoke Region's Needs Assessment ("NA") in May 2014. This RIP provides a consolidated summary of the needs and recommended plans for the Burlington to Nanticoke Region for the near-term (up to 5 years) and the mid-term (5 to 10 years).

It should be noted that this RIP, in addition to advancing the work from the aforementioned IRRPs, also identifies additional needs related to sustainment and end-of-life facilities in the Hamilton area. Built over 50 years ago, the transmission assets in the Hamilton area are some of the oldest installations in the province. At the time of the Burlington to Nanticoke Need Assessment and Scoping Assessment phases, done in 2014, the detailed information on the condition and end-of-life issues related to these assets was not available. As such, a decision was made by the Working Group at that time to not initiate a coordinated planning exercise for the Hamilton subsystem. Since then, through the RIP process, the extent and urgency of the sustainment work in the Hamilton area, and also in Oakville and Brantford, are better known to the Working Group.

This RIP discusses those needs and the projects developed to address those needs. Implementation to address some of these needs is underway. The plans presented in this RIP to address new end-of-life needs have been developed by Hydro One and needs also confirmed by the LDC. Further details are being formalized by Hydro One through assessment and consultation with the LDC to develop implementation plans. The plans for Beach TS, Birmingham TS, Gage TS and Kenilworth TS were later also reviewed by the IESO as part of an ongoing study for the Hamilton area. However, new near and mid-term needs namely Horning TS, Elgin TS, and Bronte TS were not fully identified earlier in the regional planning process and did not undergo a review by the IESO in the earlier phases due to their scope or project status.

The RIP report also identifies long-term needs associated with the revised and better defined sustainment plan.

The needs and/or plans in the near-term (2016-2020) and the mid- to long-term (beyond 2020) are provided below in Table 1 and Table 2, respectively, along with their planned in-service date and estimated cost, where applicable. Table 1 identifies both the stakeholders involved in each project's development and which formal regional planning process it originated from. The table also indicates the needs identified after the completion of the NA and SA (Scoping Assessment) processes.

Table 1: Near-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs	Plans	Status	I/S Date	Cost ($M)
Projects Developed in Local Planning or an IRRP					
1	115 kV B7/B8 Transmission Line Capacity	Bronte TS: Load Transfer	Planning	2018	1-3
2	115 kV B12/B13 Transmission Line Capacity	Install Brant Switching Station	Planning	2019	12
3	Two New Feeders at Dundas TS #2	Dundas TS: Load Transfer	Planning	2019	8
4	Cumberland TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD (1)	-
5	Kenilworth TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD (1)	-
Projects Developed by HONI & the LDC(s), Reviewed by IESO					
6	Kenilworth TS EOL transformers & switchgear (2)	Reconfigure from 2 DESNs to single DESN	Planning	2018	19
7	Beach TS – EOL T3/T4 DESN Transformers (2)	Replace Beach TS T3/T4 Transformers	Committed	2019	17
8	Gage TS – EOL transformers & switchgear	Gage TS: Reduce from 3 DESNs to 2 DESNs	Planning	2019	37
9	115 kV B7/B8 – EOL Line Section from Burlington TS to Nelson Jct. (2)	Refurbish the EOL B7/B8 line section	Planning	2020	2
Projects Developed by HONI & the LDC(s)					
10	115 kV B3/B4 – EOL Line Section from Horning Mountain Jct. to Glanford Jct. (2)	Refurbish the EOL B3/B4 line section conductor	Planning	2018	8
11	Horning TS EOL transformers & switchgears (2)	Replace EOL transformers & refurbish switchgears	Committed	2018	37
12	Bronte TS – EOL T5/T6 DESN (2)	Replace EOL transformers & refurbish switchgear	Committed	2019	34

No.	Needs	Plans	Status	I/S Date	Cost ($M)
13	Elgin TS – EOL transformers & switchgears	Replace transformers and switchgears and reduce 2 DESNs to 1 DESN	Committed	2019	58
14	Mohawk TS (T1/T2) – Station Capacity and EOL T1/T2 Transformers	Mohawk TS Transformers Replacement	Committed	2019	14

(1) To Be Decided
(2) New needs identified by HONI

Table 2: Mid- and Long-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs/Plans	Planned I/S Date	Cost ($M)
1	Birmingham TS: 2 Metal Clad Switchgear Refurbishment (1)	2021	14
2	Dundas TS: T1/T2 switchyard refurbishment	2021	10
3	Newton TS: Station Refurbishment	2021	36
4	LV Switchgear Refurbishment at Brantford TS, Lake TS and Stirton TS	2022	46
5	Beach TS: Replace EOL T7/T8 Autotransformers and refurbish T5/T6 DESN switchgear	2025	60
6	EOL 115 kV Cables: - H5K/ H6K - K1G/ K2G - HL3/ HL4	TBD (2)	TBD (2)

(1) Preliminarily reviewed by HONI, LDC and the IESO
(2) To Be Decided

Further details of needs, alternatives, and recommended plans for the above needs are provided in Section 7. The preliminary plans and needs identified in Table 2 will be further assessed in the next planning cycle. A summary of the current recommendations for these mid- and long-term needs is provided in Section 8.

The RIP Working Group recommends the following outcomes and next steps:

a) Hydro One will continue to implement the committed and near-term projects for addressing the above needs as discussed in this report, while keeping the Working Group apprised of project status, and

b) The RIP recommends that an expedited Needs Assessment report should be developed to list these already identified needs in the mid and long term or any new needs to be followed by Scoping Assessment, led by the IESO for further assessment under the Burlington to Nanticoke regional planning Working Group.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE BURLINGTON TO NANTICOKE REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the needs, assessments and recommended plan. The members of the RIP WG included representative from Brantford Power Inc. ("Brantford Power"), Burlington Hydro Inc. ("Burlington Hydro"), Energy + Inc. ("Energy +"), Alectra Utilities Corporation (former Horizon Utilities Inc. "Alectra Utilities"), Hydro One Distribution, the Independent Electricity System Operator ("IESO") and Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The Burlington to Nanticoke region covers the City of Brantford, municipality of Hamilton, counties of Brant, Haldimand and Norfolk. The portions of Cities of Burlington and Oakville south of Dundas Street are included in the Burlington to Nanticoke region up to Third Line road in the east. Electrical supply to the Region is provided from thirty-one 230 kV and 115 kV step-down transformer stations. The summer 2015 load of the Region was about 1831 MW. The boundaries of the Region are shown in Figure 1-1 below.

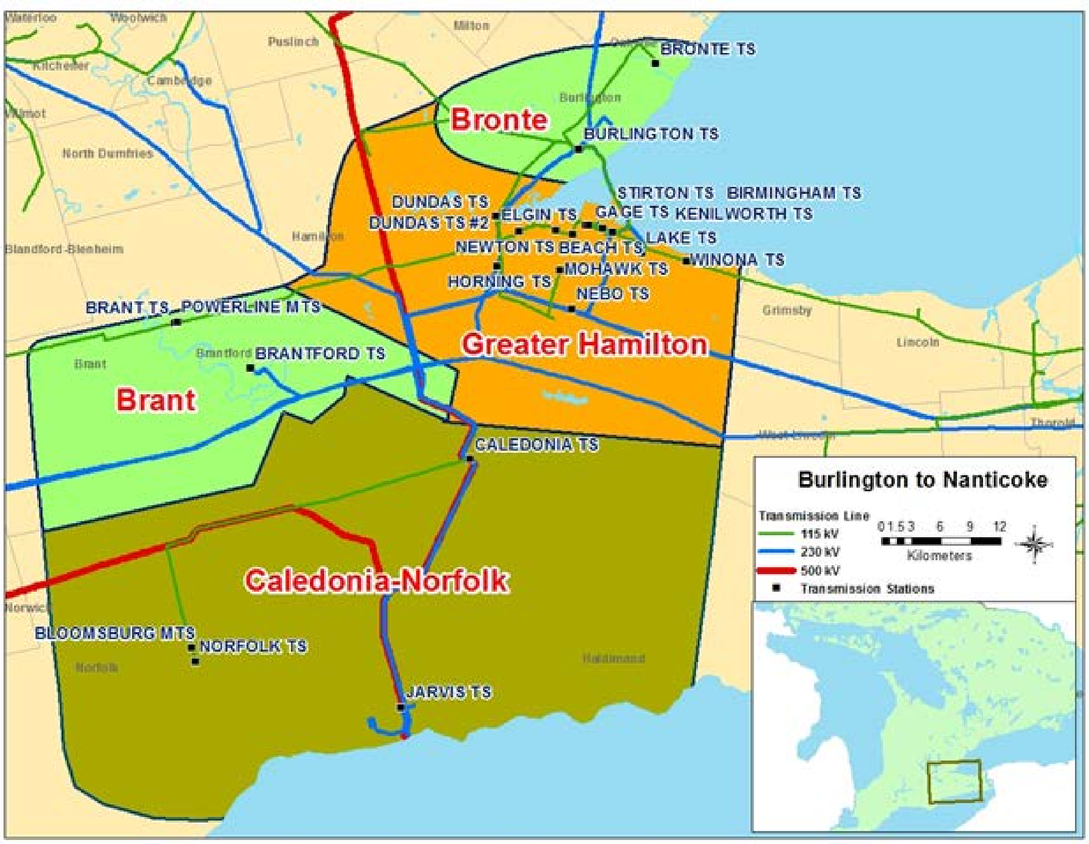

Figure 1-1 Burlington to Nanticoke Region

1.1 Objective and Scope

The RIP report examines the needs in the Burlington to Nanticoke Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA") and/or Integrated Regional Resource Plan("IRRP");
- Assess and develop a wires plan to address these new needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the mid- and long-term, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated summary of the wires plan developed during LP (Local Planning), SA (Scoping Assessment), and/or as identified in IRRP.
- Discussion of any other major transmission infrastructure investment plans over the near and mid-term (0-10 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies needs.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] Also referred to as Needs Screening

a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region. The Brant Sub-Region IESO led IRRP was initiated prior to the new regional planning process and was completed in March 2015. The need for Bronte Sub-Region IRRP was identified during the Need Assessment for Burlington to Nanticoke region and was completed in June 2016.

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- The NA, SA, and LP phases of regional planning.
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

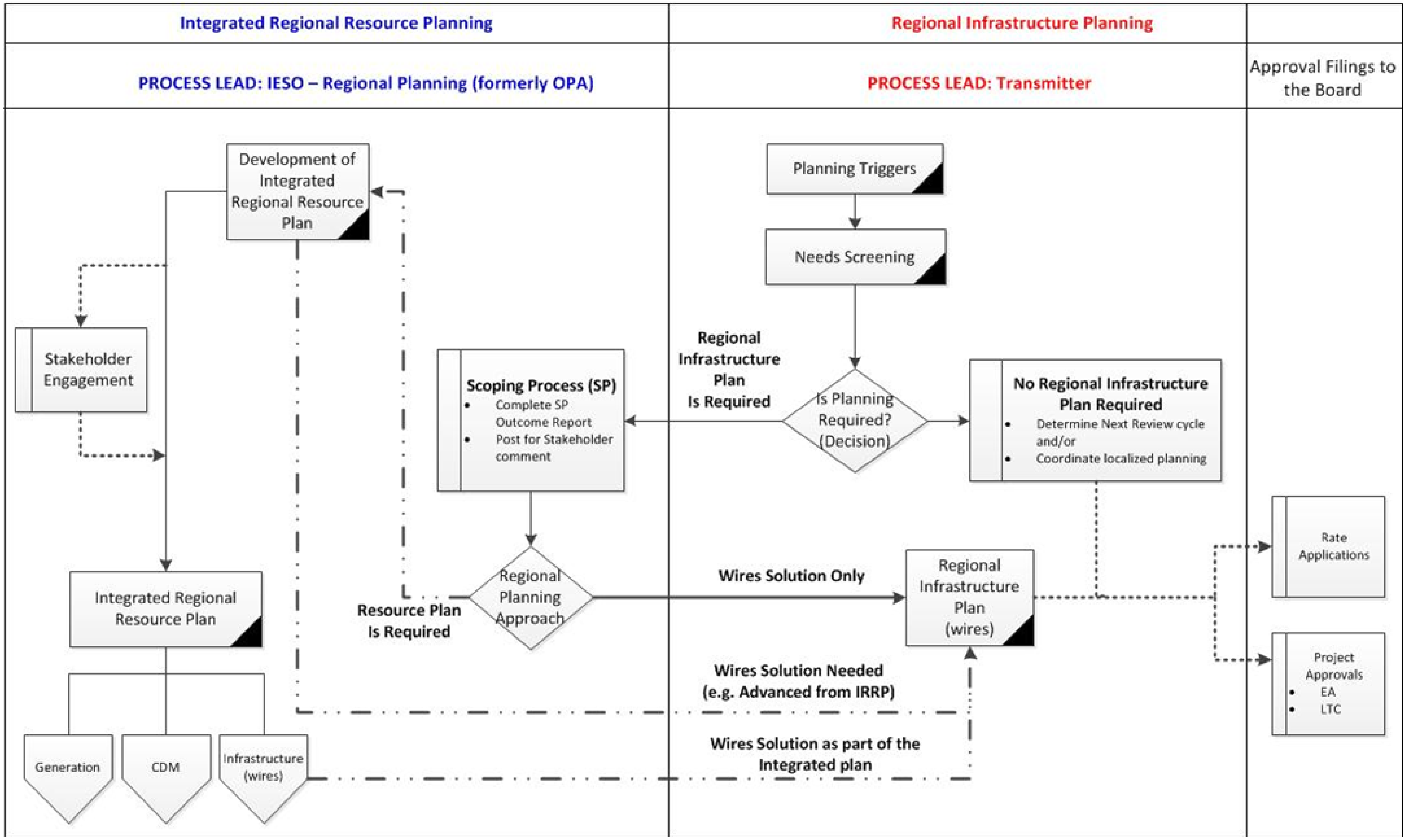

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

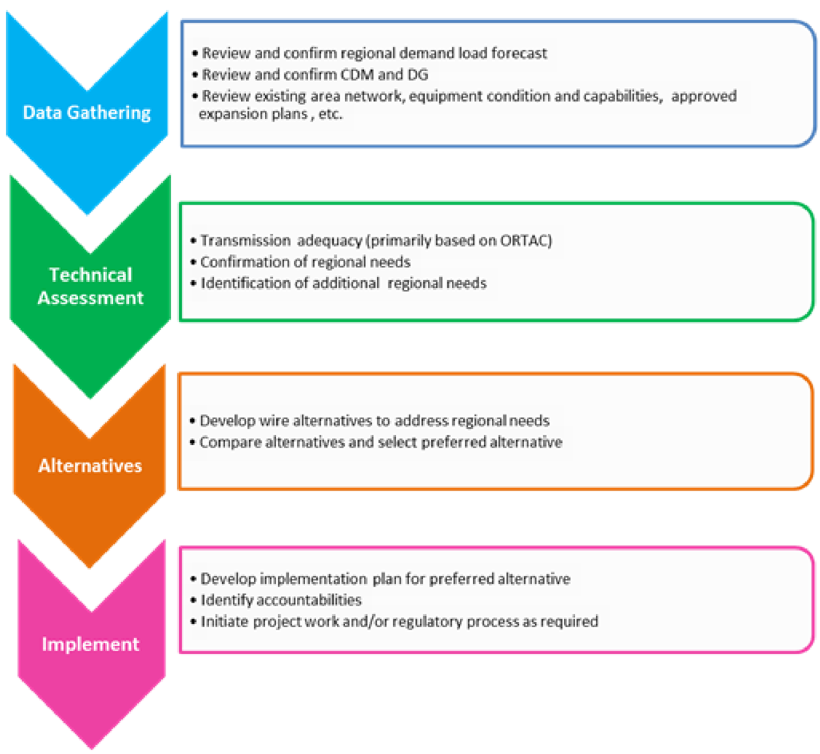

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE BURLINGTON TO NANTICOKE REGION COVERS THE CITY OF BRANTFORD, MUNICIPALITY OF HAMILTON, COUNTIES OF BRANT, HALDIMAND AND NORFOLK. SOME OF THE ELECTRICAL INFRASTRUCTURE IN THE REGION IS ONE OF THE OLDEST INSTALLATIONS IN THE PROVINCE. THE PORTIONS OF CITIES OF BURLINGTON AND OAKVILLE SOUTH OF DUNDAS STREET ARE INCLUDED IN THE BURLINGTON TO NANTICOKE REGION UP TO THIRD LINE ROAD IN THE EAST.

Bulk electrical supply to the Burlington to Nanticoke Region is provided through the 500/230 kV Nanticoke TS and Middleport TS and 230 kV circuits from Middleport TS, Nanticoke TS and Beck TS. The 115 kV network is supplied by 230/115 kV autotransformers at Burlington TS, Beach TS and Caledonia TS. The area loads are supplied by a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. The area has been divided into four sub-regions as shown in Figure 1-1 and described below:

- The Brant Sub-Region encompasses the County of Brant, City of Brantford and surrounding areas. Electricity supply to the sub-region is provided by:
  - Brant TS and Powerline MTS supplied by 115 kV double circuit line B12/B13.
  - Brantford TS supplied by the 230 kV double circuit transmission line M32W/M33W.

  The Brant Sub-Region transmission facilities are shown in Figure 3-1.

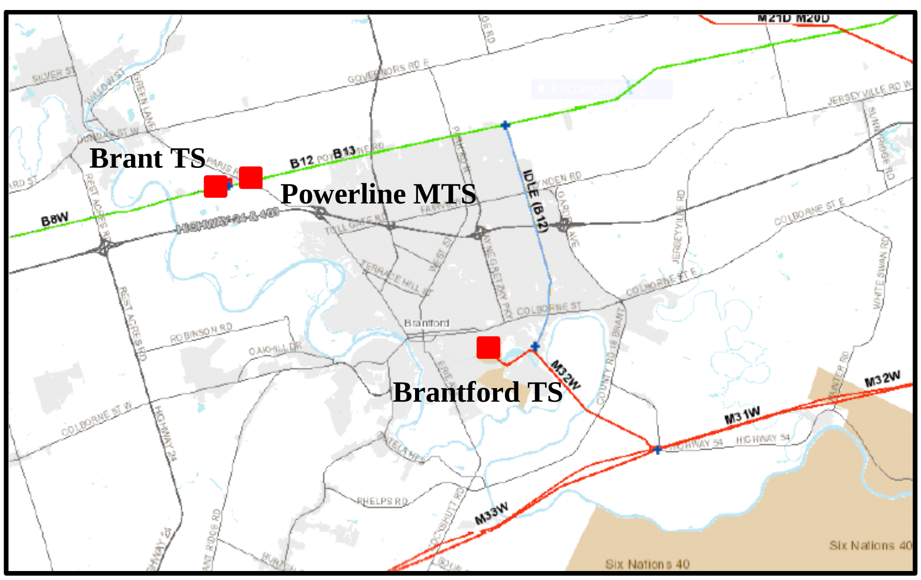

Figure 3-1 Brant Sub-Region

The total peak demand of the three stations was about 263 MW in 2015. Energy + Inc. and Brantford Power Inc. are the main LDCs that serve the electricity demand for the City of Brantford. Hydro One Distribution supplies load in the outlying areas of the sub-region. The electricity demand is comprised of residential, commercial and industrial customers.

- The Bronte Sub-Region covers the City of Burlington and the western part of the City of Oakville up to Third Line. Electricity supply to the sub-region is provided by:

  - Bronte TS supplied by 115 kV double circuit line B7/B8.
  - Burlington TS supplied by 230 kV double circuit line Q23BM/ Q25BM.
  - Cumberland TS supplied from 230 kV double circuit transmission line B40C/B41C.

  The Bronte Sub-Region transmission facilities are shown in Figure 3-2.

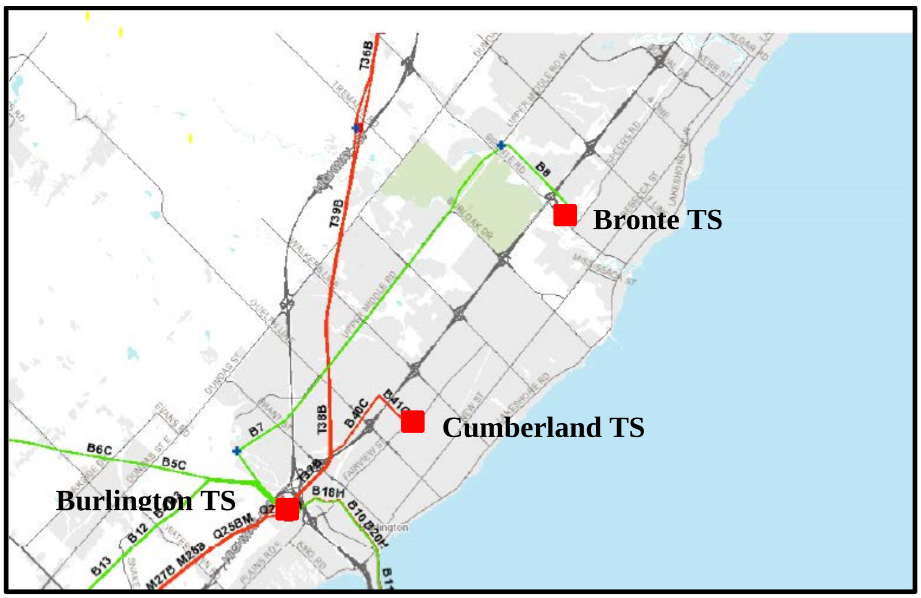

Figure 3-2 Bronte Sub-Region

The area is served by Burlington Hydro and Oakville Hydro. The electricity demand is comprised of residential, commercial and industrial customers. The total peak station demand of the three stations was about 402 MW in 2015.

- The Greater Hamilton Sub-Region encompasses the City of Hamilton that includes Townships of Flamborough and Glanbrook and towns of Dundas and Stoney Creek. Some of the electrical infrastructure in the sub-region was built over 50 years ago and is one of the oldest installations in the province. Electricity supply to the sub-region is grouped as follows:

  - Beach TS 115 kV area which includes five 115 kV step down stations Beach TS T3/T4 DESN, Birmingham TS, Kenilworth TS, Stirton TS, Winona TS and a CTS supplied from the 230/115 kV autotransformers at Beach TS.

- Burlington TS 115 kV area which includes Dundas TS, Dundas #2, Elgin TS, Gage TS, Mohawk TS, Newton TS and one customer owned CTS supplied from the 230/115 kV autotransformers at Burlington TS.

- 230 kV area which includes 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 Greater Hamilton Sub-Region transmission facilities are shown in Figure 3-3.

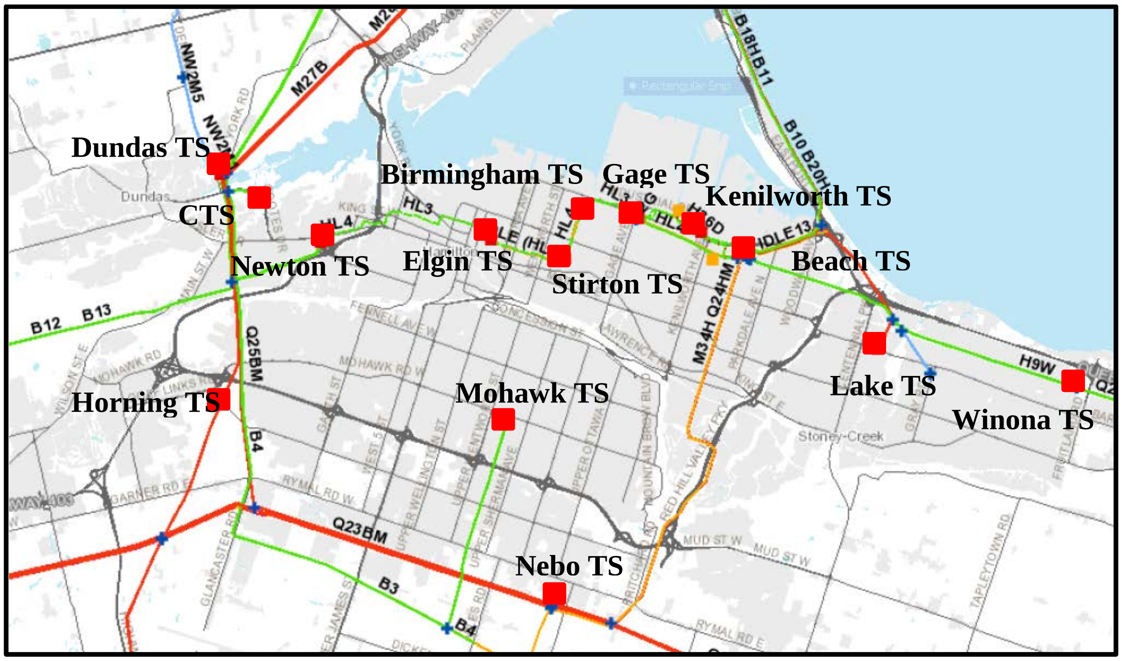

Figure 3-3 Greater Hamilton Sub-Region

The total peak station demand of the Greater Hamilton Sub-Region was about 1394 MW in 2015. The area is served by Alectra Utilities, Hydro One Distribution and CTSs comprises a significant number of large industrial customers along with commercial and residential customers.

- The Caledonia Norfolk Sub-Region covers the eastern part of Norfolk County and the western part of Haldimand County. Electricity supply to the Sub-region is provided by:

  - Caledonia TS supplied by 230 kV double circuit line N5M/S39M.
  - Jarvis TS supplied from the 230 kV double circuit line N21J/N22J.
  - Bloomsburg DS and Norfolk TS supplied from 115 kV double circuit transmission line C9/C12.

The Caledonia Norfolk Sub-Region transmission facilities are shown in Figure 3-4.

The area is served by Hydro One Distribution. The electricity demand mix is comprised of residential, commercial and industrial uses. The peak demand of the stations in the Sub-Region was approximately 334 MW in 2015.

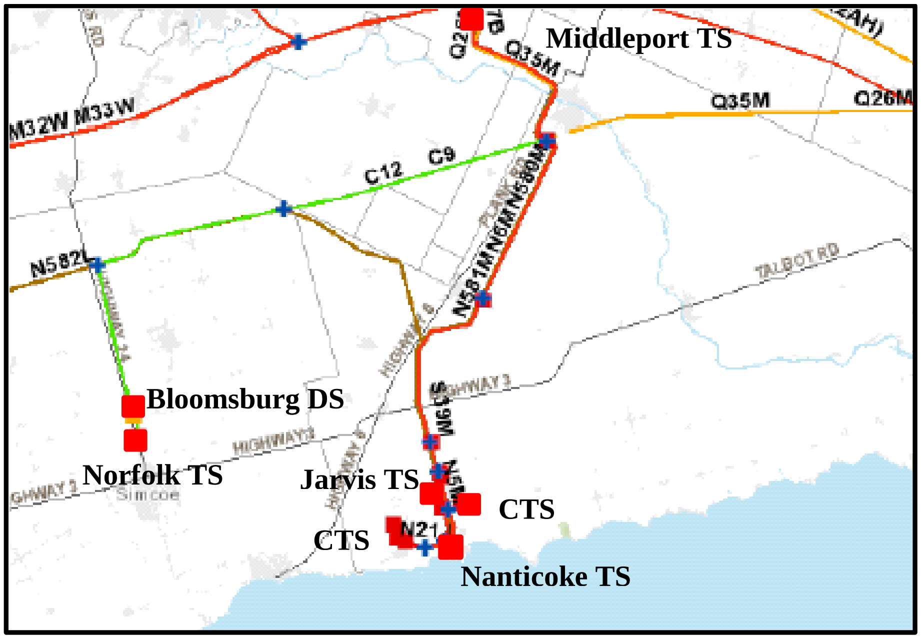

Figure 3-4 Caledonia Norfolk Sub-Region

Electrical single line diagrams for the Burlington to Nanticoke Region 500 kV/ 220 kV facilities and 115 kV facilities are shown below in Figure 3-5 and Figure 3-6.

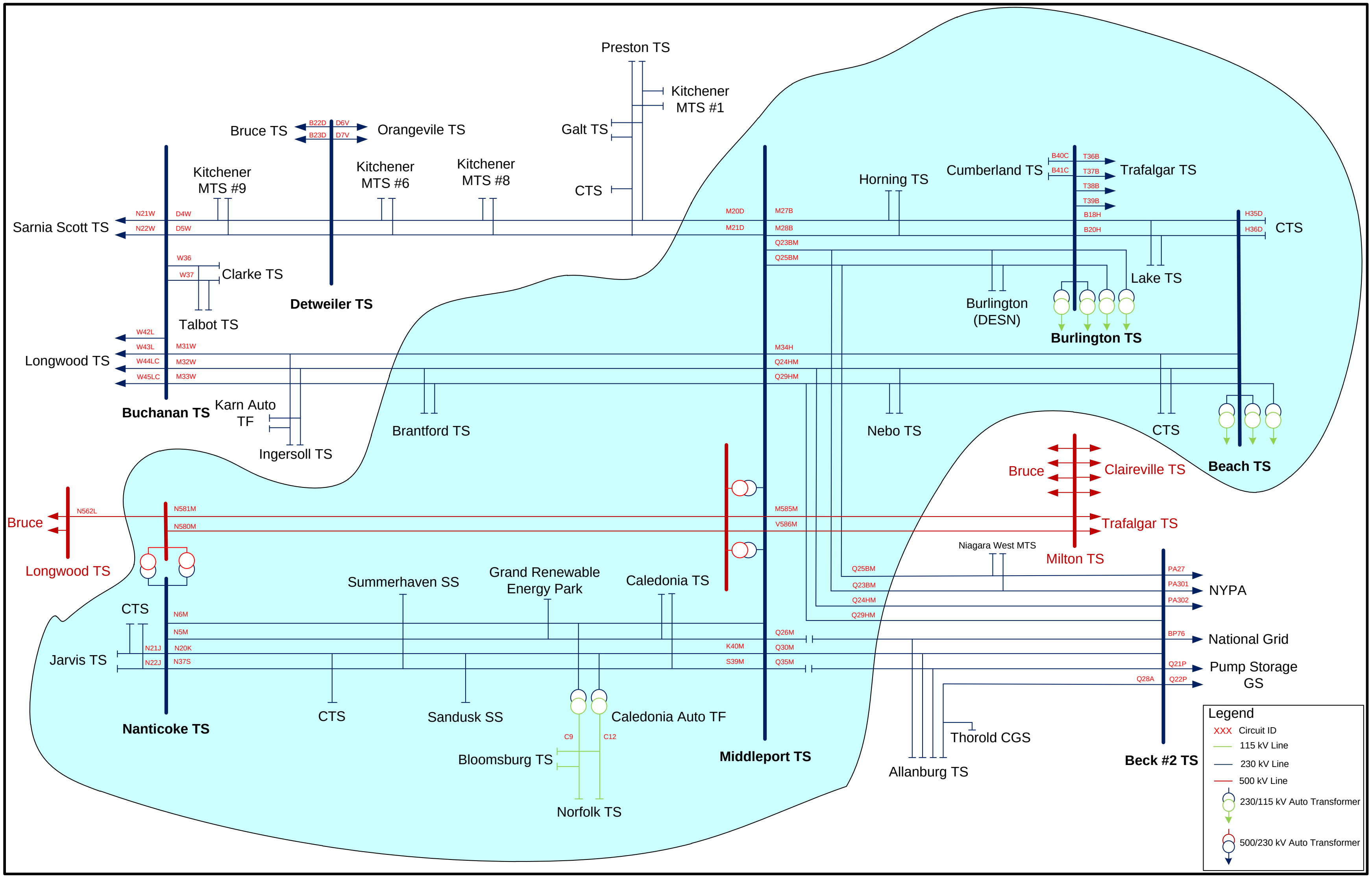

Figure 3-5 Burlington to Nanticoke Region 500 & 230 kV and Caledonia-Norfolk 115 kV Network

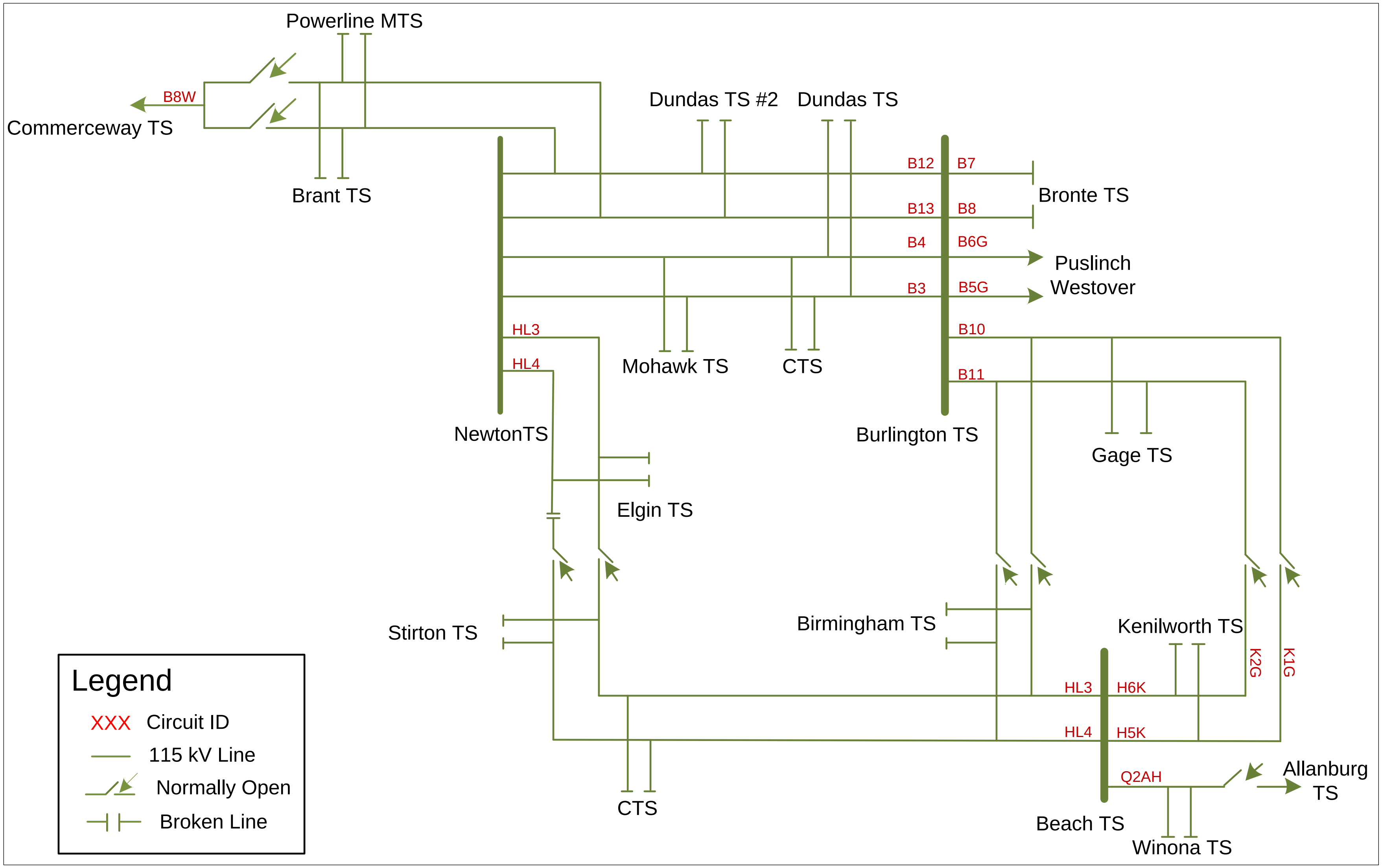

Figure 3-6 115 kV Network Supplied by Burlington TS and Beach TS

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, IN CONSULTATION WITH THE LDCs AND/OR THE IESO, AIMED TO MAINTAIN OR IMPROVE THE RELIABILITY AND ADEQUACY OF SUPPLY IN THE BURLINGTON TO NANTICOKE REGION.

A brief listing of some of the major projects completed over the last ten years are as follows:

- Bronte TS (2008) - added a new low voltage breaker between T5/T6 DESN and T2 DESN units at Bronte TS.
- Burlington TS (2009) - replaced 230 kV/115 kV autotransformer T6 following failure.
- 2nd 115 kV Supply to Norfolk TS and Bloomsburg DS (2009) – Built 12 km of new 115 kV circuit to provide 2nd supply to Norfolk TS and Bloomsburg DS.
- Jarvis TS (2011) and Caledonia TS (2012) – installed LV reactors to reduce short circuit levels below the TSC limits and to allow increased generation connection capability at these stations.
- Nebo TS (2013) – replaced T1/T2 230 kV/ 27.6 kV transformers with larger size standard units and added six new breaker positions to meet customer needs.
- Burlington TS (2016) – installed an additional 230 kV circuit breaker to reduce probability of the simultaneous loss of two autotransformers at this station improving supply reliability to the stations supplied from 115 kV Burlington TS bus.
- Transformer replacement at stations: Bronte TS (2006), Norfolk TS (2009), Birmingham TS (2010), Cumberland TS (2012), Brantford TS (2013), Kenilworth TS (2014), Dundas TS (2015) and Brant TS (2016).
- Feeder Positions – added four new breaker positions at Horning TS (2006) and two new feeder breaker positions at Bronte TS (2008) to meet the customer needs.

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5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Burlington to Nanticoke Region is growing at a slow rate with a decline of industrial loads in the region. Currently, load is forecast to increase at an average annual rate of approximately 0.24% up to 2035. The growth rate varies across the Region – with the highest growth rate of 1.37% in the Brant Sub Region.

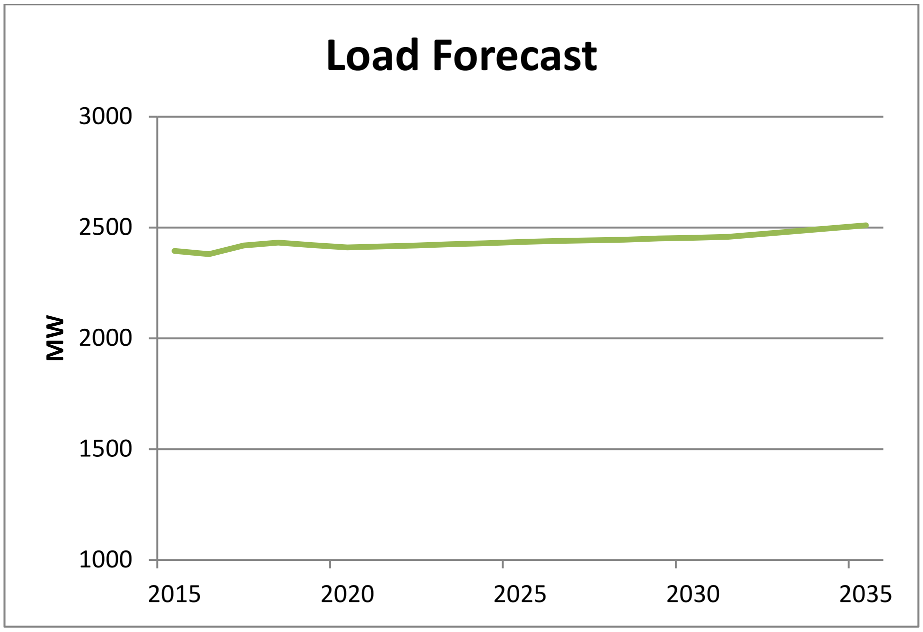

Figure 5-1 Burlington to Nanticoke Region Summer Extreme Weather Peak Forecast

Figure 5-1 shows the Burlington to Nanticoke Region peak summer non-coincident load forecast. This forecast is based on the 2015 extreme weather corrected loads. The non-coincident forecast represents the sum of the individual station's peak load and is used to determine the need for stations and line capacity. Regional non-coincident load forecast for the individual stations in the Burlington to Nanticoke Region is given in Appendix D.

The RIP load forecast was developed as follows:

- Load forecast for stations in the Bronte Sub region was taken from the IESO Bronte Sub- Region IRRP completed on June 30, 2016.
- Load forecast for Brant TS and Powerline MTS in the Brant Sub-Region was prepared by input and discussions with the LDCs recently (2016) as part of detailed planning for Brant switching station.
- Load forecast for the remaining stations was developed using the summer 2015 actual peak load adjusted for extreme weather and applying the station net growth rates provided by the LDCs. The net station loads account for CDM measures and connected DG in the region.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2015-2025.
- All planned facilities listed in Section 4 are assumed to be in-service.
- Where applicable, future industrial loads have been reduced based on historical information.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations in this sub-region is determined by the Hydro One summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE BURLINGTON TO NANTICOKE REGION OVER THE 2015-2025 PERIOD.

Within the current regional planning cycle three regional assessments have been conducted for the Burlington to Nanticoke Region. These studies are:

1) NA Report - Burlington to Nanticoke Region, May 23 , 2014
2) IRRP Report - Brant Sub-Region, April 28, 2015
3) Local Planning (“LP”) Report – Burlington to Nanticoke Region, October 28, 2015
4) IRRP Report - Bronte Sub-Region, June 30, 2016

The NA and IRRP reports identified a number of needs to meet the forecast load demands and EOL asset issues. A review of the loading on the transmission lines and stations in the Burlington to Nanticoke Region was also carried out as part of the RIP report using the latest regional forecast as given in Appendix D. Sections 6.1 to 6.5 present the results of this review. Further description of assessments, alternatives and preferred plan along with status is provided in Section 7.

6.1 500 and 230 kV Transmission Facilities

The 500 kV and most of the 230 kV transmission circuits in the Burlington to Nanticoke Region are classified as part of the Bulk Electricity System (“BES”). They connect the Region to the rest of Ontario’s transmission system. A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfers as well as local area loads. In addition there are three 230 kV double circuit lines H35D/ H36D, B40C/ B41C and N21J/ N22J that supply only local loads. The circuits supplying local loads in the region are as follows (refer to Figure 3-5):

1. Middleport TS to Burlington TS 230 kV transmission circuits M27B/ M28B - supply Horning TS.
2. Middleport TS to Beck #2 TS to Burlington TS 230 kV transmission circuits Q23BM/ Q25BM /Q24HM/ Q29HM - supply Burlington (DESN) TS, Nebo TS and one customer owned CTS.
3. Middleport TS to Buchanan TS 230 kV transmission circuits M32W/ M33W - supply Brantford TS.
4. Middleport TS to Nanticoke TS 230 kV transmission circuits N5M/ S39M / N20K - supply Caledonia TS and one customer owned CTS.
5. Burlington TS to Beach TS 230 kV transmission circuits B18H/ B20H - supply Lake TS.
6. Nanticoke TS to Jarvis TS 230 kV transmission circuits N21J/ N22J - supply Jarvis TS and one customer owned CTS.
7. Beach TS to one customer owned CTS 230 kV transmission circuits H35D/ H36D.
8. Burlington TS to Cumberland TS 230 kV transmission circuits B40C/ B41C - supply Cumberland TS.

Bulk system planning is conducted by the IESO and is informed by government policy, including policy outlined in the long term energy plan ("LTEP"). Government engagement on the next LTEP is currently underway, with a new LTEP expected to be issued in Q2/Q3 2017. Bulk system needs, options and recommendations for Power System facilities serving this region will be determined by the IESO as part of the implementation plan for the 2017 LTEP.

6.2 230/115 kV Transformation Facilities

Almost half of the Region's load is supplied from the 115 kV transmission systems. The primary source of 115 kV supply is from three 230/115 kV autotransformers at Burlington TS, Beach TS and Caledonia TS.

Table 6-1 summarizes the loading levels for all three 230 /115 kV auto transformers in the Burlington to Nanticoke region.

Table 6-1 Adequacy of 230/115 kV Autotransformer Facilities

Overloaded Facilities	MVA Load Meeting Capability	2015 MVA Loading	Need Date
Burlington TS 230/115 kV autotransformers	912	745	-[1]
Beach TS 230/115 kV autotransformers	582	348	-[1]
Caledonia TS 230/115 kV autotransformer	187	88	-[1]

[1] Adequate over the study period (2015- 2025)

The autotransformers in the Burlington to Nanticoke region are of adequate capacity over the study period (2015-2025). The Needs Assessment identified a stuck breaker scenario at Burlington TS that could result in simultaneous loss of two of the four autotransformers at Burlington TS. This is a low probability scenario under which the loading on the remaining two autotransformers could exceed their short time emergency rating.

However, recently an additional 230 kV breaker has been added to the scheme reducing the possibility of simultaneous loss of two autotransformers at Burlington TS under a single contingency scenario. In addition, installation of the new 230/115 kV autotransformers at Cedar TS and 115 kV switching at Brant TS, to be in-service by 2019, will further reduce loading on the Burlington TS autotransformers.

The loading on the Burlington TS 230/115 kV autotransformers, for the simultaneous loss of two autotransformers, is therefore expected to remain within the short term rating of the two remaining in-service autotransformers at Burlington TS. No further action is required.

6.3 115 kV Transmission Facilities

The 115 kV transmission facilities can be divided in three main sections: Please see Figure 3-5 and 3-6 for the single line diagrams.

1. Burlington 115 kV – has twelve 115 kV circuits B3/B4, B5/B6, B7/B8, B10/B11, B12/B13 and HL3/ HL4. All circuits are adequate over the study period except for sections of the B7/B8 and B12/B13 circuits as given below in Table 6-2. These needs have been identified in the earlier phases of the regional planning process and are being addressed by Hydro One as per the recommendations in respective IRRPs and further discussed in this RIP (Section 7).

   The loading on the limiting sections of 115 kV circuits is summarized below in Table 6-2.

Table 6-2 Limiting Sections of 115 kV Circuits

Line Section	Overloaded Circuit	Reference Section	Capacity (MW)	Contingency	2015 Loading (MW)	Need Date
Palermo Jct. to Bronte TS	B7/ B8	Section 7.1	135	B7	129	2018
Horning Mountain Jct. to Brant TS	B12/B13	Section 7.5	125	B12/B13	119	2019

   The HL3/ HL4 115 kV double circuit cable consist of two sections:
   i. HL3/ HL4 Newton TS to Elgin TS
   ii. HL3/ HL4 Elgin TS to Stirton TS (HL4 is idle)

   These cables provide normal and backup supply to Elgin TS. The supply capacity of 115 kV HL3/ HL4 cables is adequate over the study period (2015-2025).

2. Beach 115 kV– has five 115 kV circuits H5K/ H6K, HL3/ HL4 and Q2AH expected to be adequate over the study period. There are two associated 115 kV double circuit cable sections:
   i. K1G/ K2G Kenilworth TS to Gage TS
   ii. H5K/ H6K Kenilworth TS to Beach TS

   These cables provide normal and backup supply to Kenilworth TS. The supply capacity of Beach 115 kV cables and lines is adequate over the study period (2015-2025).

3. Norfolk Caledonia – has two 115 kV circuits C9 and C12 supplying Norfolk TS and Bloomsburg DS. The need of additional supply capacity for C9/C12 double circuit line was identified during the earlier phases of the regional planning cycle.

   The updated load forecast and further assessment as part of this RIP shows that the combined load of Norfolk TS and Bloomsburg DS will remain below the supply capacity of 87 MW of C9/ C12 line during the study period and no further action is required.

The list of all the 230 kV and 115 kV circuits is given in Appendix A.

6.4 Step-Down Transformation Facilities

There are a total of 31 step-down transmission connected transformer stations in the Burlington to Nanticoke Region. The stations have been grouped based on the geographical area and supply configuration. The station loading in each area and the associated station capacity is provided in Table 6-3 below. The complete list of all the stations in the Burlington to Nanticoke region and their supply circuits is given in Appendix B.

Table 6-3 Adequacy of Step-Down Transformer Stations

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
Brant Sub-Region	403	263	-(2)
Bronte Sub-Region	530	402	-(2)
Greater Hamilton Sub-Region (1)	1919	1108	-(2)
Caledonia Norfolk Sub-Region (1)	351	211	-(2)

(1) Excludes Customer Transformer Stations (CTS)
(2) Adequate over the study period (2015-2025)

Dundas TS has two DESN units T1/T2 and T5/T6. During the earlier phases of the Regional Planning cycle T1/T2 DESN at Dundas TS was found to be loaded over its supply capacity due to unbalanced loading between the two Dundas TS DESNs. The current loading at both DESNs at Dundas TS is within each DESN's supply capacity. Further assessment as part of this RIP based on current forecast confirms that the loads on each of the Dundas TS DESNs will remain within its supply capacity during the study period. No further action is required.

Nebo TS 13.8 kV T3/T4 DESN was also identified as marginally over loaded during an earlier phase of the regional planning cycle. Further assessment as part of this RIP based on updated forecast confirms that the loads on the Nebo TS T3/T4 DESN will remain within its supply capacity during the study period. No further action is required.

6.5 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

a. All loads must be restored within 8 hours.
b. Load interrupted in excess of 150 MW must be restored within 4 hours.
c. Load interrupted in excess of 250 MW must be restored within 30 minutes.

It is expected that all loads can be restored within 8 hours in the Burlington to Nanticoke Region over the study period. None of the transmission circuits in the Burlington to Nanticoke region will be supplying total loads in excess of 250 MW. The following double circuit lines in the Burlington to Nanticoke Region are expected to supply the loads in excess of 150 MW at peak times:

- B12/ B13
- B3/ B4
- H35D/ H36D
- HL3/ HL4
- M32W/ M33W
- Q23BM/ Q25BM
- Q24HM/ Q29HM

Based on the historical performance and reliability data for these circuits in the region, the Working Group recommended that no action is required at this time.

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7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES THE ELECTRICAL INFRASTRUCTURE NEEDS FOR THE BURLINGTON TO NANTICOKE REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THESE NEEDS. THESE NEEDS INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE NEEDS ASSESSMENT, SCOPING ASSESSMENT, IRRPS FOR THE BRANT, AND BRONTE SUB-REGIONS, ASSESSMENTS CARRIED OUT IN SECTION 6 AS WELL AS EMERGING NEEDS DUE TO AGING INFRASTRUCTURE AND END OF LIFE ISSUES.

This section outlines and discusses infrastructure needs and plans identified for the Burlington to Nanticoke Region and recommended plans and/or next steps for the near-term (up to 5 years) and the mid-to long-term (beyond 5 years).

It should be noted that this RIP, in addition to advancing the work from the aforementioned IRRPs, also identifies additional needs related to sustainment and end-of-life facilities in the Hamilton area. Built over 50 years ago, the transmission assets in the Hamilton area are some of the oldest installations in the province. At the time of the Burlington to Nanticoke Need Assessment and Scoping Assessment phases, done in 2014, the detailed information on the condition and end-of-life issues related to these assets was not available. As such, a decision was made by the Working Group at that time to not initiate a coordinated planning exercise for the Hamilton subsystem. Since then, through the RIP process, the extent and urgency of the sustainment work in the Hamilton area, and also in Oakville and Brantford, are better known by the Working Group.

This RIP discusses those needs and the projects developed to address those needs. Implementation to address some of these needs is already or nearly underway. The plans presented in this RIP to address new end-of-life needs have been developed by Hydro One and needs also confirmed by the LDC. Further details are being formalized by Hydro One through assessment and consultation with the LDC to develop implementation plans. The plans for Beach TS, Birmingham TS, Gage TS and Kenilworth TS were later reviewed by the IESO as part of an ongoing study for the Hamilton area. However, new near and mid-term needs namely Horning TS, Elgin TS, and Bronte TS were not fully identified earlier in the regional planning process and did not undergo a review by the IESO in the earlier phases due to their scope or project status.

The RIP report also identifies long-term needs associated with the revised and better defined sustainment plan. These needs will be assessed in the next planning cycle. A summary of all of these needs in the near-term (2016-2020) and mid to long-term (beyond 2020) are listed in Table 7-1 and Table 7-2, respectively, along with their in-service date, where applicable. Table 7-1 identifies both the stakeholders involved in each project's development and which formal regional planning process it originated from and provide reference to sub-sections with further details for each of the need. The table also indicates the needs identified after the completion of the NA and SA processes.

Table 7-1 Identified Near-Term Needs in Burlington to Nanticoke Region

No.	Needs	Section	Timing
Projects Developed in Local Planning or an IRRP			
1	115 kV B7/B8 Transmission Line Capacity	7.1	2018
2	115 kV B12/B13 Transmission Line Capacity	7.2	2019
3	Two New Feeders at Dundas TS	7.3	2019
4	Cumberland TS – Power Factor Correction	7.4	TBD
5	Kenilworth TS – Power Factor Correction	7.5	TBD
Projects Developed by HONI & the LDC(s), Reviewed by IESO			
6	Kenilworth TS – EOL transformers & switchgear (1)	7.6	2018
7	Beach TS – EOL T3/T4 DESN Transformers (1)	7.7	2019
8	Gage TS – EOL transformers & switchgear	7.8	2019
9	115 kV B7/B8 – EOL Line Section from Burlington TS to Nelson Jct. (1)	7.9	2020
Projects Developed by HONI & the LDC(s)			
10	115 kV B3/B4 – EOL Line Section from Horning Mountain Jct. to Glanford Jct. (1)	7.10	2018
11	Horning TS – EOL transformers & switchgears (1)	7.11	2018
12	Bronte TS – EOL T5/T6 DESN (1)	7.12	2019
13	Elgin TS – EOL transformers & switchgears	7.13	2019
14	Mohawk TS (T1/T2) – Station Capacity & EOL T1/T2 Transformers	7.14	2019

(1) New needs identified by HONI

The mid- and long-term (2021-2025) electrical infrastructure needs in the Burlington to Nanticoke Region are summarized below in Table 7-2. Where available, a preliminary plan to address that need is provided in the corresponding sub-section.

Table 7-2 Identified Mid- and Long-Term Needs in Burlington to Nanticoke Region

No.	Needs	Section	Timing
1	Birmingham TS EOL Metalclad Switchgears	7.15	2021
2	Dundas TS EOL T1/T2 Switchgear	7.16	2021
3	Newton TS EOL Transformers, Switchgears, Breakers	7.17	2021
4	Brantford TS EOL Switchgear	7.18	2022
5	Lake TS EOL Switchgear	7.18	2022

No.	Needs	Section	Timing
6	Stirton TS EOL Switchgear	7.18	2022
7	Beach TS EOL T7/T8 Auto-transformers and T5/T6 Switchgear	7.19	2025
8	EOL Cables in Hamilton area: H5K/H6K, K1G/K2G, HL3/HL4	7.20	TBD

The needs identified in the Burlington to Nanticoke Region in the above Tables 7-1 and Table 7-2 are further discussed below.

7.1 115 kV Circuit B7/B8 Transmission Line Capacity (Burlington TS to Bronte TS)

7.1.1 Description

Bronte TS is radially supplied by the 115 kV double circuit B7/ B8 line from Burlington TS. The supply capacity of Bronte area is limited to 135 MW due to loading on B7/B8 exceeding its thermal capacity following a loss of either of the circuits starting in 2018. In 2021, the post contingency voltage drop for the loss of either circuit will also exceed the ORTAC limit of 10% at Bronte TS. The load in Bronte area is forecasted to exceed the 135 MW supply limit and reach about 150 MW during the study period.

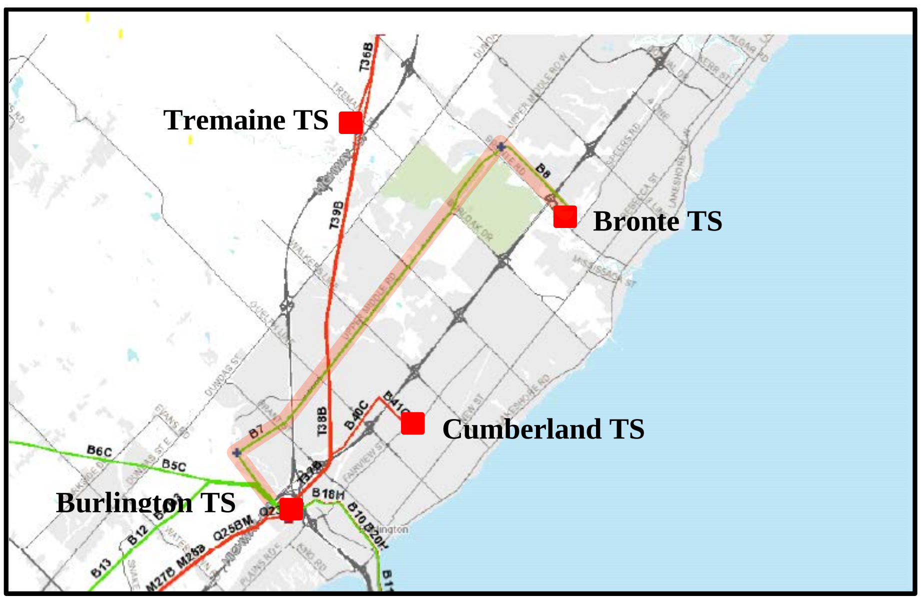

Figure 7-1 Bronte TS Supply Circuits B7/B8

7.1.2 Recommended Plan

The Working Group considered and reviewed different options to provide relief to the 115 kV circuits supplying Bronte TS as part of the Bronte area IRRP. The options included: a) upgrading of transmission system to mitigate the limitation on the 115 kV B7/ B8 circuits and b) Distribution option to transfer load from Bronte TS to neighboring station(s). Upgrading of transmission system was neither economical nor a practical solution.

Consistent with the WG recommendations in the IRRP, the most cost effective and preferred alternative is for LDC(s) to transfer loads from Bronte TS to other neighboring stations and to maintain Bronte TS loading below 135 MW.

Hydro One and the affected LDCs will develop a plan by the end of 2017 for transferring approximately 15 MW of load from Bronte TS to the neighboring station(s). The estimated cost of investments for the distribution load transfer is currently expected to be in the order of $1-3 million.

7.2 115 kV Circuit B12/B13 Transmission Line Capacity (Burlington TS to Brant TS)

7.2.1 Description

Brant TS and Powerline MTS in Brant County are supplied by the 115 kV double circuits B12/B13 line from Burlington TS. The Brant area is experiencing higher growth with a number of new industrial customers planning to connect over the next few years. The combined load of Brant TS and Powerline MTS was 119 MW in summer 2015 and exceeds the 104 MW supply capacity of the B12/B13 line.

7.2.2 Recommended Plan

As per the IRRP recommendations, first phase was to provide additional capacity for the Brant Area's 115 kV supply that included installation of 40 MVAR capacitor banks at Powerline MTS in July 2015. This has increased the line supply capacity to 125 MW.

In addition, the IRRP Working Group considered other options to provide additional 115 kV capacity to supply Brant TS and Powerline MTS to address future load growth over the near-term. The most economical option that was recommended by the WG is to install a three breaker switching station at Brant TS and using the existing backup supply from 115 kV circuit B8W (from Karn TS) as third supply. A single line diagram of the new switching facilities at Brant TS is shown below in Figure 7.2.

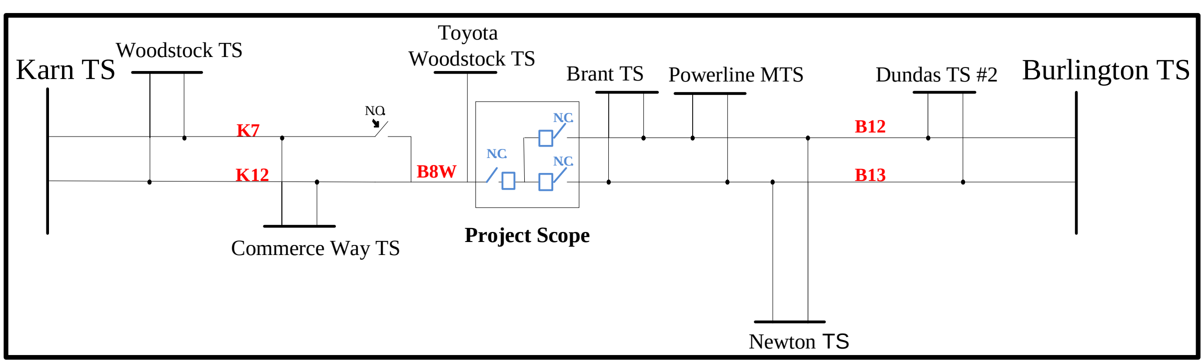

Figure 7-2 Brant Sub-Region Proposed Configuration

Hydro One has initiated detailed engineering work and design. The project is expected to be in-service by spring 2019 and is estimated to cost approximately $12 million. The installation of the switching station will reclassify some of the line connection assets as Network Assets. The project cost will be recoverable from the rate revenue and/or capital contribution from the LDCs in accordance with the TSC.

7.3 Two New Feeders at Dundas TS

7.3.1 Description

Dundas TS has two DESN units T1/T2 and T5/T6 with a total 2015 summer peak load of 148 MW and a station supply capacity of 188 MW. The station capacity is forecasted to be sufficient over and beyond the study period.

A LDC currently supplied from the T1/T2 DESN is planning to transfer load to T5/T6 DESN and supplied from two existing spare breaker positions to meet increased load needs. This will also help in balancing the loads between the two Dundas TS DESNs.

7.3.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address customer’s needs:

- <u>Maintain status quo</u>: This alternative was considered and rejected as it does not address the customer’s needs.
- <u>Transfer customer load to T5/T6 DESN</u>: Move portion of LDC customer loads from T1/T2 DESN to T5/T6 DESN utilizing two spare breaker positions at T5/T6 DESN. This will require reconfiguring of distribution assets by the LDC and will also help improving load balancing between two Dundas TS DESNs.

The preferred plan is to proceed with moving portion of the LDC’s customer load from T1/T2 DESN to T5/T6 DESN utilizing two spare breaker positions. The transfer of load from T1/T2 DESN to T5/T6 DESN is planned to be completed in 2019 at an estimated cost of $8 million.

7.4 Cumberland TS Power Factor Correction

7.4.1 Description

The Cumberland TS supplies up to 123 MW of loads in the city of Burlington. The historical loading data of Cumberland TS indicated that under peak load conditions the power factor at Cumberland TS is lagging slightly below the ORTAC requirement of 0.9.

7.4.2 Recommended Plan and Current Status

The Needs Assessment identified this need and it was recommended that Burlington Hydro to work with their load customers supplied by Cumberland TS and install capacitor banks on distribution system as required to meet the minimum power factor requirements of 0.9.

Burlington Hydro is currently perusing different options to improve the power factor of customer loads supplied by Cumberland TS to meet ORTAC requirement. This issue will be further reviewed during the next regional planning cycle.

7.5 Kenilworth TS Power Factor Correction

7.5.1 Description

There are two supply stations inside Kenilworth TS T1/T4 and T2/T3 supplying about 60 MW of loads in the city of Hamilton. The historical loading data of Kenilworth TS indicated that under peak load conditions the power factor at Kenilworth TS is lagging below the ORTAC requirement of 0.9.

7.5.2 Alternatives and Recommended Plan

The Needs Assessment identified this need and it was recommended that Alectra Utilities to install capacitor bank on distribution system and/or work with load customers supplied by Kenilworth TS to meet ORTAC power factor requirement of 0.9.

Alectra Utilities is currently perusing option on cost and location to install equipment to improve power factor to meet ORTAC requirement. This issue will be further reviewed during the next regional planning cycle.

7.6 Kenilworth TS End of Life Assets

7.6.1 Description

There are two DESN units T1/T4 and T2/T3 inside Kenilworth TS supplying loads in the city of Hamilton and built in 1950's and 1960's respectively. The load at Kenilworth TS is currently about 60 MW. The T1/T4 transformers are rated at 67 MVA each while the T2/T3 transformers are 100MVA and 120 MVA, respectively, which are non-standard as per current standards. Non-standard and obsolete equipment results in complexity with failures and difficulty in getting similar spare equipment along with their installation. The original 120 MVA T2 transformer was replaced with a standard 100 MVA transformer unit in 2014 due to failure. In addition, one of the three metalclad switchgears at Kenilworth TS is presently out of service while the second in-service metalclad switchgear is approaching end of its useful life. As a result, near-term plan is developed to address the failure and EOL issues.

7.6.2 Alternatives and Recommended Plan

The following alternatives are considered to address end of life issue at Kenilworth TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
- "Like-for-Like" replacement of the assets: This alternative would require maintaining four transformers and the associated three switchgears which is not justifiable based on the load forecast.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring Kenilworth TS. This alternative was considered but is not feasible due to: a) unique electrical characteristics and requirements of industrial costumer load in the area, and b) higher costs associated with reconfigurations and transfer of customer loads.
- Reconfiguration of the station reducing to two supply transformers and two switchgears: This option will reconfigure and adequately downsize the station. In this configuration, station will be reduced from four transformers to only two transformers supplying two switchgears.

The preferred plan is for Hydro One to proceed with the reconfiguration of the station and reduce it to two transformers and two switchgears only. The recently replaced transformer and one of the existing metalclad switchgear will be utilized while one transformer and switchgear will be required to be replaced. The new transformer will be a standard unit similar to T2 that was replaced in 2014. This refurbishment project is currently planned to be completed by the year 2018 at an estimated cost of $19 million.

7.7 Beach TS EOL T3/T4 DESN Transformers

7.7.1 Description

Beach TS has two DESN units T3/T4 and T5/T6 supplying loads in the city of Hamilton and built in 1950's and 1960's respectively. The T3/T4 DESN is supplied by the 115 kV bus while the T5/T6 DESN is supplied from the 230 kV bus at Beach TS. The 115/13.8 kV T3/T4 DESN transformers have been identified by Hydro One approaching the end of their useful life and require replacement. The load at Beach TS T3/T4 DESN is currently about 32 MW and is forecasted to stay at the same level in the foreseeable future.

7.7.2 Alternatives and Recommended Plan

The following alternatives are considered to address Beach TS T3/T4 supply transformer end of life issue:

- Continue to maintain the assets (status quo): This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
- "Like-for-Like" replacement of the assets: Replacing existing EOL 115/ 13.8 kV T3/T4 DESN transformers with similarly sized units.

- Reconfigure 115 kV T3/T4 transformers to a 230 kV configuration by replacing the existing non-standard 115/ 13.8 kV (67 MVA + 75 MVA) transformers with standard 100 MVA 230/13.8 kV units.

Keeping the existing supply configuration at 115 kV of T3/T4 transformers at Beach TS is not possible as it does not meet safety clearance requirements. In light of this and the fact that moving the transformer supply configuration from 115 kV to 230 kV bus is similar in cost plus has other long-term advantages, such as the 230 kV supply option will result in reduced loading levels of 230/115 kV Beach TS autotransformers resulting in freeing up capacity and improve supply reliability.

The preferred plan is for Hydro One to proceed with reconfiguring the 115 kV T3/T4 DESN to a 230 kV configuration by replacing the existing non-standard transformers with standard 100 MVA 230/13.8 kV units is the most suitable option. The project is currently underway, and is expected to be completed in 2019. The cost of this investment is currently estimated at about $17 million.

7.8 Gage TS End of Life T3/T4/T5/T6 Transformers and a Switchgear

7.8.1 Description

Gage TS has three DESNs (T3/T4, T5/T6, and T8/T9) predominantly supplying large industrial customer loads in Hamilton. T3/T4 and T5/T6 DESNs were built in the 1940's with each transformer rated at 63 MVA LTR, while T8/T9 DESN was built in 1960's with each transformer rated at 137 MVA LTR. These transformers are non-standard with unique electrical characteristics with high short circuit requirements of the customer. The transformers T3, T4, T5, and T6, as well as T5/T6 DESN at Gage TS have been identified by Hydro One at their EOL and have been previously deferred to better understand customer load requirements. Transformer T5 has failed multiple times and breakers in the T5/T6 DESN have experienced recurring problems. No issues or refurbishment needs have been identified at T8/T9 DESN at this time.

The load at Gage TS has reduced over the years to approximately 48 MW, and is currently expected to stay at this level over the study period. The existing station capacity (of the three DESNs) is about 240 MW. Although there seems to be over-capacity at Gage TS, unique short-circuit and connection requirements of industrial loads at this station limits the feasibility of some of the alternatives/solutions.

7.8.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address end of life issues at Gage TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, safety issues and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
- "Like-for-Like" replacement of the assets: This alternative would continue maintaining six transformers and the associated three switchgears. This option is extremely costly and cannot be justified since the load has significantly reduced at this station.

- Station/load consolidation: Moving loads to neighboring station(s) and retiring Gage TS. This alternative is not feasible due to: a) unique costumer load requirements (i.e., high short circuit currents are required to operate customer's large arc furnaces and large motors without significant impact to power quality), and b) higher costs associated with reconfigurations of LV cables and transfer of customer loads to other stations.
- Reconfiguration of the station and downsize the station from three DESN to two DESN station: In this option, the station will be reconfigured and downsized from the existing six transformers to four transformers.

The preferred plan is for Hydro One to proceed with the reconfiguration of the station and reduce it from 3 DESNs to 2 DESNs. Under this plan, T3/T4 and T5/T6 DESNs will be replaced by a single T10/T11 DESN with two 100 MVA standard units and switchgear currently supplied by T5/T6 transformers will also be replaced. This option will also provide future flexibility to eliminate T8/T9 DESN when it approached EOL.

The refurbishment of Gage TS is currently expected to be completed in 2019 at an estimated cost of $37 million.

7.9 115 kV Circuit B7/B8 End of Life Section (Burlington TS to Nelson Junction)

7.9.1 Description

The 115 kV double circuit line B7/B8 line supplies about 130 MW of Burlington and Oakville area loads through Bronte TS. The line section from Burlington TS to Nelson junction (about 2.3 km) was built in 1920's. Hydro One has identified that the conductor on this line section from Burlington TS to Nelson junction has reached end of useful life.

7.9.2 Alternatives and Recommended Plan

The following alternatives are considered to address 115 kV B7/B8 end of life line section from Burlington TS to Nelson junction:

- Maintain status quo: This alternative was considered and rejected as it does not address the EOL issue, risk of failures resulting in poor supply reliability and would result in increased maintenance expenses.
- Refurbishment of EOL line section: Refurbish 2.3 km of EOL line conductor section of B7/B8 line section.

The preferred plan is to proceed with the refurbishment of the 115 kV B7/ B8 line section from Burlington TS to Nelson junction supplying Bronte TS using similar ACSR conductor. The refurbishment work is planned to be completed by the year 2020 and estimated to cost approximately $2 million.

7.10 115 kV B3/B4 End of Life Line Section (Horning Mountain Jct. to Glanford Jct.)

7.10.1 Description

The 115 kV B3/B4 line supplies Hamilton area loads through Dundas TS (T1/T2 DESN), a CTS and Mohawk TS. Mohawk TS is supplied from B3/B4 line through about 16 km long line-tap supplying about 84 MW of load. A section of this line tap has a solid copper conductor from Horning Mountain Jct. to Glanford Jct. which is approximately 100 year old and has reached end of useful life.

7.10.2 Alternatives and Recommended Plan

The following alternatives are considered to address the above need:

- Continue to maintain the assets (status quo): This alternative was considered and rejected as it does not address the frequent failure, increased maintenance expenses and poor supply reliability.
- Refurbishment of EOL line section: Replace EOL copper conductor with 605 kcmil ACSR conductor Mohawk TS line tap section.

The preferred plan is for Hydro One to replace this EOL copper conductor with 605 kcmil ACSR from Horning Mountain Jct. to Glanford Jct. supplying Mohawk TS. This work is currently planned to be completed by 2018 at an estimated cost of $8 million.

7.11 Horning TS End of Life Assets

7.11.1 Description

Horning TS is a 230/13.8 kV DESN station built in 1967 and supplies Alectra Utilities loads in the Hamilton area. It has two station supply transformers of 100 MVA each supplying load through its two metalclad switchgears. Recent equipment failures in 2016 due to aging low voltage switchgear have adversely impacted supply to customers in the Hamilton area along with safe operations.

In addition, both the transformers and both low voltage switchgears at Horning TS are approaching end of expected useful life and have been identified by Hydro One for replacement. The load at Horning TS is currently about 70 MW and is forecasted to stay at the same level during the study period.

7.11.2 Alternatives and Recommended Plan

The following alternatives are considered to address Horning TS end of life issue:

- Continue to maintain the assets (status quo): This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.

- "Like-for-Like" replacement of the assets: This alternative would continue maintaining current station configuration and only replace existing transformers will similar units and refurbish both metalclad switchgears.

The preferred plan is for Hydro One to proceed with Like-for-Like replacements replacing supply transformers with similar 100 MVA units and refurbishing EOL low voltage metalclad switchgears. The new replaced transformers and refurbished switchgear will provide sufficient capacity to serve the load over the study period. The project is currently underway, and is expected to be completed in 2018. The cost of this investment is estimated to be about $37 million.

7.12 Bronte TS End of Life T5/T6 DESN

7.12.1 Description

Bronte TS was placed in service in 1963 and is radially supplied from Burlington TS via 115 kV B7/ B8 circuits. The total load at Bronte TS is currently about 129 MW and is forecasted to stay at about 135 MW with load transfers as proposed in section 7.1.

There are three transformers, T2 (single transformer configuration), and T5/T6 DESN (83 MVA), at Bronte TS supplying loads in the cities of Oakville and Burlington. Transformer T2 was replaced in 2006 and the T5/T6 DESN transformers at Bronte TS and LV switchgear is approaching end of expected useful life. Hydro One has identified that these transformers require replacement.

7.12.2 Alternatives and Recommended Plan

The following alternatives are considered to address end of life Bronte TS T5/T6 DESN refurbishment:

- Continue to maintain the assets (status quo): This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
- "Like-for-Like" replacement of the assets: Replacing existing EOL 115/ 27.6 kV T5/T6 DESN transformers with similar size standard units and refurbish switchgear.

The preferred plan is for Hydro One to proceed with Like-for-Like replacement. This will include replacing existing 83 MVA T5/T6 transformers with similar units and refurbishing associated switchgear. This investment is estimated to be approximately $34 million with planned in-service of 2019.

7.13 Elgin TS End of Life Assets

7.13.1 Description

Elgin TS has two DESNs (T1/T2 and T3/T4) built in 1960's supplying loads in the city of Hamilton through three switchgears. The current load at Elgin TS is approximately 85 MW, and is currently expected to stay at this level over the study period.

The T1/T2 transformers are 75 MVA units while the T3/T4 units are non-standard 33 MVA units. All existing four transformers (T1, T2, T3, and T4) and three switchgears at Elgin TS have been identified by Hydro One as approaching end of their useful life. This need was identified in the Needs Assessment phase.

7.13.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address end of life issues at Elgin TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, safety issues and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
- "Like-for-Like" replacement of the assets: This alternative would continue maintaining four transformers and the associated three switchgears. This option is extremely costly and cannot be justified with load forecast not showing any growth at this station.
- Reconfiguration and downsize the station from two DESNs to one DESN station: In this option, the station will be reconfigured and downsized from the existing four transformers to two transformers.

The preferred plan is for Hydro One to proceed with the reconfiguration of the station and reduce it to two transformers and two switchgears only. Under this plan, T1/T2 and T3/T4 DESNs will be replaced by a single T5/T6 DESN with two 100 MVA standard units and four new switchgears. This will maintain adequate supply capacity to the loads through the four new switchgears. The cost of this investment is expected to be $58 million with a planned in service of 2019.

7.14 Mohawk TS Station Supply Capacity & End of Life T1/T2 Transformers

7.14.1 Description

Mohawk TS is a 115/13.8 kV step down transformer station supplied from 115 kV circuit B3/B4 from Burlington TS supplying loads in the city of Hamilton. The station supply capacity is limited to 80 MW by the LTR of transformers. The 2015 summer peak load was 84 MW and the station is marginally over its supply limits during peak load periods. In addition, transformers at Mohawk TS are over 50 years old and condition assessment has identified Mohawk TS transformers approaching end of their useful life.

7.14.2 Alternatives and Recommended Plan

The following alternatives were considered to address Mohawk TS end of life transformer issue:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, poor supply reliability and would result in increased maintenance expenses. In addition option will not address the capacity needs at the station,
- Transformer replacement: Replacing the existing non-standard (67 MVA) end of life transformers with new standard (75 MVA) units.

The preferred plan is for Hydro One to proceed with the replacement of existing nonstandard supply transformers at Mohawk TS with the standard 75 MVA units. This will address the issue of: a) EOL transformers, b) replace non-standard equipment with standard units, and c) will provide sufficient station supply capacity. In the interim, Alectra Utilities will manage the overloads (under contingency) by distribution loads transfers. The transformer replacement project is currently expected to be in service by 2019 at an estimated cost of $14 million.

7.15 Birmingham TS End of Life Switchgear

7.15.1 Description

Birmingham TS is located in the city of Hamilton having two DESN units T1/T2 and T3/T4 of 75 MVA each. Both the DESNs at Birmingham TS can supply a total load of about 185 MVA (LTR). The Birmingham TS currently supplies a large industrial customer with unique connection requirements. The load at Birmingham TS is forecasted at about 75 MW.

At this time transformers and/or other HV equipment at this station has not been identified as EOL over the study period. However, two 13.8 kV LV metalclad switchgears are at EOL and have been identified by Hydro One for refurbishment.

7.15.2 Recommended Plan

The two end of life 13.8 kV LV end of life metalclad switchgears at Birmingham TS are required to be replaced to meet the unique connection needs of the customer at this station. Not replacing the end of life switchgears will increase the risk of failure due to asset condition and adversely impact supply to a large industrial customer. Currently Hydro One plans to complete this by 2021. This need will be further reviewed in the next regional planning cycle.

7.16 Dundas TS End of Life Switchgear

7.16.1 Description

Dundas TS has two DESN units T1/T2 and T5/T6 with a total 2015 summer peak load of 148 MW and station capacity of 188 MW. The station capacity is forecasted to be sufficient over and beyond the study period. The T1/T2 transformers at Dundas TS have recently been replaced in 2015. The Dundas TS T1/T2 27.6 kV MV switchgear has been identified by Hydro One at end of life requiring refurbishment.

7.16.2 Alternatives and Recommended Plan

Hydro One has identified MV 27.6 kV T1/T2 switchgear at Dundas TS at end of life requiring refurbishment. Keeping status quo not refurbishing this switchgear will increase the risk of failure due to asset condition reducing supply reliability to the customers and would result in increased maintenance expenses.

The refurbishment switchgear is currently planned by Hydro One to be completed by 2021. This need is recommended to be further reviewed in the next regional planning cycle.

7.17 Newton TS End of Life Transformers and Switchgear

7.17.1 Description

Newton TS is a 115 kV/ 13.8 kV DESN station having transformers built in 1956 and supplies Alectra Utilities loads in the city of Hamilton. It has two station supply transformer of 67 MVA each supplying loads through its 13.8 kV switchyards. The customer load at the station is about 50 MW and is forecasted to stay at the same level in the foreseeable future. Hydro One in initial assessment has identified that both transformers and switchgear requiring refurbishment. The scope of refurbishment is subject to final asset condition assessment of Newton TS to be completed in 2017.

7.17.2 Alternatives and Recommended Plan

The following alternatives are considered to address Newton TS end of life asset issue:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance cost.
- Replacement of the assets: Replace existing EOL non-standard transformers with similarly sized units and refurbish switchgear to current standards.

The current plan is to refurbish Newton TS with new equipment built to current standards including two 75 MVA units replacing existing 67 MVA transformers and LV switchgear. This is the preferred alternative since it addresses the needs at Newton TS and maintaining station's operability and reliability of supply. This refurbishment work at Newton TS is planned by Hydro One to be completed by 2021. This need is recommended to be further reviewed in the next regional planning cycle.

7.18 Mid-Term End of Life LV Switchyard Refurbishment

7.18.1 Description

Hydro One has identified the LV switchyards reaching end-of-life by 2022 and need to be refurbished at the following stations:

1. Brantford TS
2. Lake TS
3. Stirton TS

7.18.2 Recommended Plan

The Working Group is recommending that these needs to be further reviewed in the next regional planning cycle.

7.19 Beach TS End of Life T7/T8 Autotransformers and T5/T6 DESN LV Switchgear

7.19.1 Description

Beach TS is a major switching and transformer station in East Hamilton. Station facilities include a 230 kV switchyard, three 230/115 kV autotransformers (T1/T7/T8), a 115 kV switchyard, a 230/13.8 kV DESN T5/T6 and a 115/13.8 kV DESN T3/T4.

Hydro One has determined that autotransformers T7 and T8 and the T5/T6 DESN LV Metalclad switchgear are expected to reach end of life by 2025 and will need to be replaced.

7.19.2 Recommended Plan

The Working Group is recommending that this need be further reviewed in the next regional planning cycle.

7.20 End of Life Cables in Hamilton Area: HL3/HL4, K1G/K2G, H5K/H6K

Underground cables in Hamilton area (listed below) are expected to be approaching end-of-life over the next 10 years or so.

- 115 kV H5K/H6K Cable (Beach TS to Kenilworth TS)
- 115 kV K1G/K2G Cable (Kenilworth TS to Gage TS)
- 115 kV HL3/HL4 Cable (Newton TS to Elgin TS)
- 115 kV HL3/HL4 Cable (Elgin TS to Stirton TS)

In light that replacement of the high voltage underground cables can be complicated, affect upstream transmission system and expensive requires alternative/s to be developed and assessed ahead of time. The WG has recommended further review of the cable replacement needs and development of a tentative plan in the next regional planning cycle.

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8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE BURLINGTON TO NANTICOKE REGION.

A list and summary of all the needs and/or plans in the near-term (2016-2020) and mid to long term (beyond 2020) is provided below in Table 8-1 and Table 8-2, respectively, along with their in-service date and estimated cost, where applicable. Where available, preliminary plans to address the mid- to long-term needs were also provided.

Table 8-1 Near-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs	Plans	Status	I/S Date	Cost ($M)
Projects Developed in Local Planning or an IRRP					
1	115 kV B7/B8 Transmission Line Capacity	Bronte TS: Load Transfer	Planning	2018	1-3
2	115 kV B12/B13 Transmission Line Capacity	Install Brant Switching Station	Planning	2019	12
3	Two New Feeders at Dundas TS	Dundas TS: Load Transfer	Planning	2019	8
4	Cumberland TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD	-
5	Kenilworth TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD	-
Projects Developed by HONI & the LDC(s), Reviewed by IESO					
6	Kenilworth TS EOL transformers & switchgear (1)	Reconfigure from 2 DESNs to single DESN	Planning	2018	19
7	Beach TS – EOL T3/T4 DESN Transformers (1)	Replace Beach TS T3/T4 DESN Transformers	Committed	2019	17
8	Gage TS – EOL transformers & switchgear	Gage TS: Reduce from 3 DESNs to 2 DESNs	Planning	2019	37
9	115 kV B7/B8 – EOL Line Section from Burlington TS to Nelson Jct. (1)	Refurbish the EOL B7/B8 line section	Planning	2020	2
Projects Developed by HONI & the LDC(s)					
10	115 kV B3/B4 – EOL Line Section from Horning Mountain Jct. to Glanford Jct. (1)	Refurbish the EOL B3/B4 line section conductor	Planning	2018	8
11	Horning TS EOL transformers & switchgears (1)	Replace EOL transformers & refurbish switchgears	Committed	2018	37

No.	Needs	Plans	Status	I/S Date	Cost ($M)
12	Bronte TS – EOL T5/T6 DESN [1]	Replace EOL transformers & refurbish switchgear	Committed	2019	34
13	Elgin TS – EOL transformers & switchgears	Replace transformers and reduce 2 DESNs to 1 DESN	Committed	2019	58
14	Mohawk TS (T1/T2) – Station Capacity and EOL T1/T2 Transformers	Mohawk TS Transformers Replacement	Committed	2019	14

(1) New needs identified by HONI

Table 8-2 Mid- and Long-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs/Plans	Planned I/S Date	Cost ($M)
1	Birmingham TS: 2 Metal Clad Switchgear Refurbishment [1]	2021	14
2	Dundas TS: T1/T2 switchyard refurbishment	2021	10
3	Newton TS: Station Refurbishment	2021	36
4	LV Switchgear Refurbishment at Brantford TS, Lake TS and Stirton TS	2022	46
5	Beach TS: Replace EOL T7/T8 Autotransformers and refurbish T5/T6 DESN switchgear	2025	60
6	EOL 115 kV Cables: - H5K/ H6K - K1G/ K2G - HL3/ HL4	TBD [2]	TBD [2]

(1) Preliminarily reviewed by HONI, LDC and the IESO
(2) To Be Decided

It is the recommendation of RIP Working Group:

a) Hydro One will continue to implement the committed and near-term projects for addressing the above needs as discussed in this report, while keeping the Working Group apprised of project status, and
b) The RIP recommends that an expedited Needs Assessment report should be developed to list these already identified needs in the mid and long term or any new needs to be followed by Scoping Assessment, led by the IESO for further assessment under the Burlington to Nanticoke regional planning Working Group.

9. REFERENCES

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[3]. Hydro One, “Needs Screening Report, Burlington to Nanticoke Region”, 23 May 2014.
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[6]. Independent Electricity System Operator, “Review of Ontario Interties”, 14 October 2014.
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APPENDIX A: TRANSMISSION LINES IN THE BURLINGTON TO NANTICOKE REGION

No.	Location	Circuit Designations	Voltage (kV)
1	Beach TS - CTS	H35D, H36D	230
2	Beach TS - Burlington TS	B18H, B20H	230
3	Beach TS - Middleport TS	M34H	230
4	Beach TS - Middleport TS - Beck #2 TS	Q24HM, Q29HM	230
5	Burlington TS - Cumberland TS	B40C, B41C	230
6	Burlington TS - Middleport TS	M27B, M28B	230
7	Burlington TS - Middleport TS - Beck #2 TS	Q23BM, Q25BM	230
8	Middleport TS - Beck #2 TS	Q30M	230
9	Middleport TS - Buchanan TS	M31W, M32W, M33W	230
10	Middleport TS - Detweiler TS	M20D, M21D	230
11	Middleport TS - Nanticoke TS	N5M, N6M	230
12	Middleport TS - Summerhaven SS	S39M	230
13	Middleport TS - Sandusk SS	K40M	230
14	Nanticoke TS - Jarvis TS	N21J, N22J	230
15	Summerhaven SS - Nanticoke TS	N37S	230
16	Sandusk SS - Nanticoke TS	N20K	230
17	Beach TS - Gage TS	B10, B11	115
18	Beach TS - Kenilworth TS	H5K, H6K	115
19	Beach TS - Newton TS	HL3, HL4	115
20	Beach TS - Winona TS	Q2AH	115
21	Beach TS - CSS	H9W	115
22	Burlington TS - Brant TS	B12, B13	115
23	Burlington TS - Bronte TS	B7, B8	115
24	Burlington TS - Cedar TS	B5G, B6G	115
25	Burlington TS - Newton TS	B3, B4	115
26	Caledonia TS - Norfolk TS	C9, C12	115
27	Kenilworth TS - Gage TS (Idle)	K1G, K2G	115

APPENDIX B: STATIONS IN THE BURLINGTON TO NANTICOKE REGION

No.	Station	Voltage (kV)	Supply Circuits
1	CTS	230	H35D, H36D
2	Beach TS	230	Beach TS 230 kV Bus (1)
3	Beach TS	115	Beach TS 115 kV Bus (2)
4	Birmingham TS	115	HL3, HL4
5	Bloomsburg DS	115	C9, C12
6	Brant TS	115	B12, B13
7	Brantford TS	230	M32W, M33W
8	Bronte TS	115	B7, B8
9	Burlington TS DESN	230	Q23BM, Q25BM
10	Caledonia TS	230	N5M, S39M
11	Cumberland TS	230	B40C, B41C
12	CTS	230	Q24HM, Q29HM
13	Dundas TS	115	B3, B4
14	Dundas TS #2	115	B12, B13
15	Elgin TS	115	HL3, HL4
16	Gage TS	115	B10, B11
17	Horning TS	230	M27B, M28B
18	CTS	230	N20K
19	Jarvis TS	230	N21J, N22J
20	Kenilworth TS	115	H5K, H6K
21	Lake TS	230	B18H, B20H
22	CTS	115	B3, B4
23	Mohawk TS	115	B3, B4
24	Nebo TS	230	Q24HM, Q29HM
25	Newton TS	115	Newton TS 115 kV Bus (3)
26	Norfolk TS	115	C9, C12
27	Powerline MTS	115	B12, B13
28	CTS	115	HL3, HL4
29	Stirton TS	115	HL3, HL4
30	CTS	230	N21J, N22J
31	Winona TS	115	Q2AH

(1) Beach TS 230 kV bus is supplied by five 230 kV B18H, B20H, Q24HM, Q29HM and M34H circuits

(2) Beach TS 115 kV bus is supplied by three 230 kV/ 115 kV autotransformers at Beach TS

(3) Newton TS 115 kV bus is supplied by four 115 kV B3, B4, B12 and B13 circuits

APPENDIX C: DISTRIBUTORS IN THE BURLINGTON TO NANTICOKE REGION

Distributor Name	Station Name	Connection Type
Energy + Inc.	Brant TS	Dx, Tx
	Brantford TS	Dx
Brantford Power Inc.	Brant TS	Tx
	Brantford TS	Tx
Brantford Power Inc. and Energy + Inc.	Powerline MTS	Tx
Burlington Hydro Inc.	Bronte TS	Tx
	Burlington TS	Tx
	Cumberland TS	Tx
Haldimand County Hydro Inc.	Caledonia TS	Dx, Tx
	Jarvis TS	Dx, Tx
Alectra Utilities Corporation	Beach TS	Tx
	Birmingham TS	Tx
	Dundas TS	Dx, Tx
	Dundas TS #2	Tx
	Elgin TS	Tx
	Gage TS	Tx
	Horning TS	Tx
	Kenilworth TS	Tx
	Lake TS	Dx, Tx
	Mohawk TS	Tx
	Nebo TS	Dx, Tx
	Newton TS	Tx
	Stirton TS	Tx
	Winona TS	Tx
Hydro One Networks Inc.	Brant TS	Tx
	Caledonia TS	Tx
	Dundas TS	Tx
	Dundas TS #2	Tx
	Jarvis TS	Tx
	Lake TS	Tx
	Nebo TS	Tx
	Norfolk TS	Dx, Tx
	Bloomsburg DS	Dx, Tx
Oakville Hydro Electricity Distribution Inc.	Bronte TS	Tx

APPENDIX D: AREA STATIONS NON COINCIDENT NET LOAD FORECAST (MW)

Sub-Region	Station	LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Brant 115 kV	Brant TS	101	59	61	63	67	68	69	70	72	74	76	79	81	84	86
	Powerline MTS	114	69	67	70	71	72	73	75	77	80	83	86	89	92	95
	Total	215	128	128	134	138	140	143	145	149	154	159	165	170	175	181
Brant 230 kV	Brantford TS	188	135	134	153	156	156	156	156	157	157	158	159	160	163	165
	Total	188	135	134	153	156	156	156	156	157	157	158	159	160	163	165
Bronte 115 kV	Bronte TS (T2)	75	59	60	62	63	64	65	66	67	68	68	68	68	69	70
	Bronte TS (T5/T6)	96	70	71	72	74	75	76	77	79	80	80	80	80	81	82
	Total	171	129	131	134	138	139	141	143	146	148	148	148	148	150	152
Bronte 230 kV	Burlington (DESN) TS	185	151	153	154	154	155	156	157	159	160	163	165	168	170	171
	Cumberland TS	174	123	122	122	122	123	124	124	126	127	129	131	133	135	136
	Total	359	273	275	276	277	278	279	281	284	288	291	296	301	304	307
Greater Hamilton 115 kV	Beach TS (T3/T4)	75	32	32	32	31	31	31	31	31	30	30	30	30	30	30
	Birmingham TS (T1/T2)	76	32	31	31	31	31	30	30	30	30	30	30	29	30	30
	Birmingham TS (T3/T4)	91	46	46	46	45	45	45	44	44	44	44	43	43	43	43
	Dundas TS	99	85	91	93	93	93	84	84	84	84	85	85	85	86	87
	Dundas TS #2	89	63	65	68	70	72	72	71	71	71	70	70	69	70	70
	Elgin TS (T1/T2)	80	63	62	62	62	61	59	58	58	58	57	57	57	57	57
	Elgin TS (T3/T4)	42	22	22	22	21	21	21	21	21	21	21	21	20	21	21
	Gage TS (T3/T4)	60	22	22	22	21	21	21	21	21	21	21	21	20	21	21
	Gage TS (T5/T6)	57	11	11	11	11	11	11	11	10	10	10	10	10	10	10
	Gage TS (T8/T9)	123	15	15	15	15	15	15	15	15	14	14	14	14	14	14
	Kenilworth TS (T1/T4)	36	29	28	28	28	28	28	28	27	27	27	27	27	27	27
	Kenilworth TS (T2/T3)	64	31	31	31	31	30	30	30	30	30	30	29	29	29	29
	Mohawk TS	80	84	83	83	83	83	82	82	82	81	81	80	79	80	80
	Newton TS	78	47	47	48	47	47	47	47	46	46	46	45	45	45	46
	Stirton TS	112	50	50	50	49	49	49	49	48	48	48	47	47	47	48
	Winona TS	89	46	48	51	51	50	50	50	49	49	49	49	48	48	49
	Total CTS		59	59	60	60	61	61	61	61	61	61	61	61	61	61
	Total		736	745	752	750	749	735	732	729	726	723	719	715	719	723
Greater Hamilton 230 kV	Beach TS (T5/T6)	91	41	44	43	43	47	47	47	46	46	46	46	45	45	46
	Horning TS	102	71	73	76	76	76	75	75	75	74	74	73	73	73	73
	Lake TS (T1/T2)	94	57	57	56	56	55	55	55	54	54	54	53	53	53	54
	Lake TS (T3/T4)	113	55	54	54	55	55	54	54	54	54	53	53	53	53	53
	Nebo TS (T1/T2)	178	119	113	116	119	123	123	124	127	129	131	133	136	140	144
	Nebo TS (T3/T4)	51	50	49	50	51	51	50	50	50	50	49	49	49	49	49
	Total CTS		265	265	265	265	244	244	244	244	244	244	244	244	244	244
	Total		658	655	661	665	651	650	650	650	651	652	652	652	658	663
Caledonia Norfolk 115 kV	Norfolk TS	97	59	56	55	55	54	54	54	53	53	53	52	52	52	52
	Bloomsburg DS	56	42	30	29	27	27	27	27	27	27	27	27	27	27	27
	Total	153	101	87	85	82	82	81	81	80	80	80	79	78	79	80
Caledonia Norfolk 230 kV	Caledonia TS	99	45	41	42	42	42	42	43	44	45	45	46	47	48	50
	Jarvis TS	99	66	62	61	61	61	61	61	62	62	63	63	63	64	66
	Total CTS		123	123	123	123	123	123	123	123	123	123	123	123	123	123
	Total		233	226	226	226	226	226	227	228	230	231	232	233	235	238
Regional Total			2394	2379	2419	2432	2421	2411	2415	2425	2434	2442	2450	2458	2483	2509

APPENDIX E: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Greater Ottawa

REGIONAL INFRASTRUCTURE PLAN

December 2, 2015

hydro one

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Hydro Ottawa Limited
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)
Hydro Hawkesbury Inc.
Ottawa River Power Corporation

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GREATER OTTAWA REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro Ottawa Limited
- Hydro Hawkesbury Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Hydro One Networks Inc. (Transmission)
- Ottawa River Power Corporation

This RIP provides a consolidated summary of needs and recommended plans for both the Ottawa Area Sub-Region and Outer Ottawa Area Sub-Region that make up the Greater Ottawa Region for the near term (up to 5 years) and the mid-term (5 to 10 years). No long term needs and associated plans (10 to 20 years) have been identified.

This RIP is the final phase of the regional planning process and it follows the completion of the Ottawa Sub-Region's Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 and the Outer Ottawa Area Sub-Region's Needs Assessment ("NA") Study by Hydro One in July 2014.

The major infrastructure investments planned for the Greater Ottawa Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost
1	Almonte TS: addition of breaker to sectionalize line M29C	November 2015	$4.7M
2	Russell TS and Riverdale TS: construction of feeder ties to allow extra load transfers	2017-2020	$2.0M
3	Lisgar TS: replacement of transformers T1 and T2	December 2017	$13.9M
4	Hawthorne TS: replacement of autotransformers T5 and T6	May 2018	$15.7M
5	Overbrook TS: replacement of transformers T3 and T4	June 2018	$1.1M(1)
6	115kV Circuit A6R: additional tap to off load Circuit A4K	June 2019	$9-11M
7	Hawthorne TS: replacement of transformers T7 and T8 and add one 44kV feeder position	October 2019	$1.1M(2)
8	King Edward TS: Replace Transformer T4	June 2021	$12M

(1) The transformers are at end of life and are being replaced as part of Hydro One sustainment program. The cost shown here represents the incremental cost of installing the next larger size units.
(2) Incremental cost for larger transformer only.

The IRRP study had also identified the need for additional 230/115 kV autotransformation capacity at Merivale TS and provision for a supply for a new station in the southwest area. The options to address these needs are still being studied by the Working Group and as part of the IESO community engagement activities. The Working Group expects to finalize recommendation to address these needs by summer 2016.

Investments to address the other mid-term needs, for cases where a decision is not required until 2020, will be reviewed and finalized in the next regional planning cycle.

No long term needs were identified at this time. As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GREATER OTTAWA REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the joint study carried out by Hydro One, Hydro Ottawa Limited ("Hydro Ottawa"), Hydro Hawkesbury Inc. ("Hydro Hawkesbury"), Ottawa River Power Corporation ("ORPC") and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The Greater Ottawa Region covers the municipalities bordering the Ottawa River from Arnprior in the West to Hawkesbury in the East and North of Highway 43. At the center of this region is the City of Ottawa. Electrical supply to the Region is provided from fifty-two 230 kV and 115 kV step-down transformer stations. The summer 2015 area load of the Region was about 1800 MW. The boundaries of the Region are shown in Figure 1-1 below.

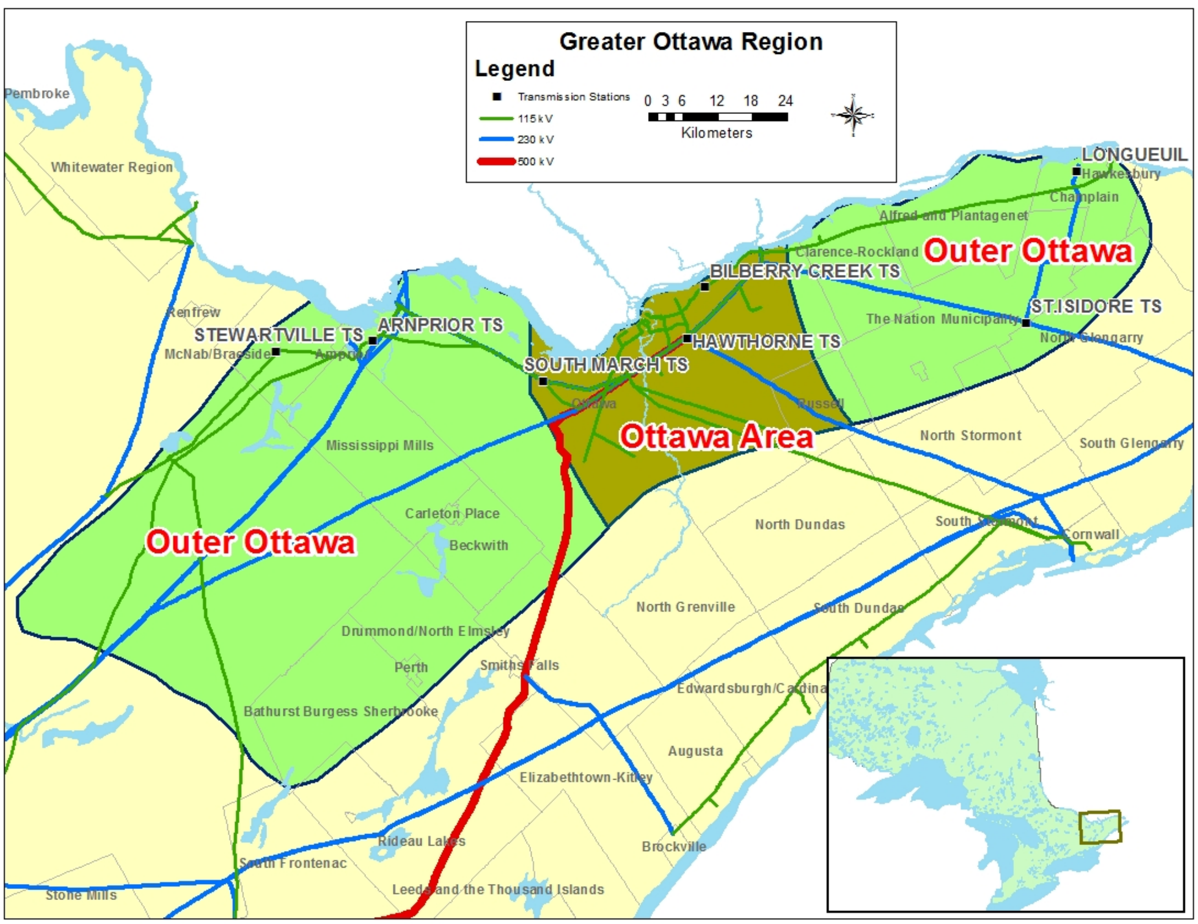

Figure 1-1 Greater Ottawa Region

1.1 Scope and Objectives

This RIP report examines the needs in the Greater Ottawa Region. Its objectives are to: identify new supply needs that may have emerged since previous planning phases (e.g. Needs Assessment, Local Plan, and/or Integrated Regional Resource Plan); assess and develop a wires plans to address these needs; provide the status of wires planning currently underway or completed for specific needs; and identify investments in transmission and distribution facilities or both that should be developed and implemented to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan).
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information.
- Develop a plan to address any longer term needs identified by the Working Group

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the region.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] Also referred to as Needs Screening.

a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region. Since the Ottawa Sub-Region was in transition to the new regional planning process, the IESO led IRRP engagement for this sub-region was initiated after the completion of the IRRP.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

The regional planning process specifies a 20 year planning assessment period for the IRRP. No specific period has been specified for the RIP. The RIP focuses on the wires options and, given the forecast uncertainty and the fact that adequate time is available to identify and plan new wire facilities in subsequent planning cycles, a study period of 10 years is considered adequate for the RIP. The only exception would be the case where major regional transmission is required for an area with limited or no transmission facilities. In these cases the RIP would review and assess longer term needs if identified in the IRRP.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- The NA, SA, and LP phases of regional planning.
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

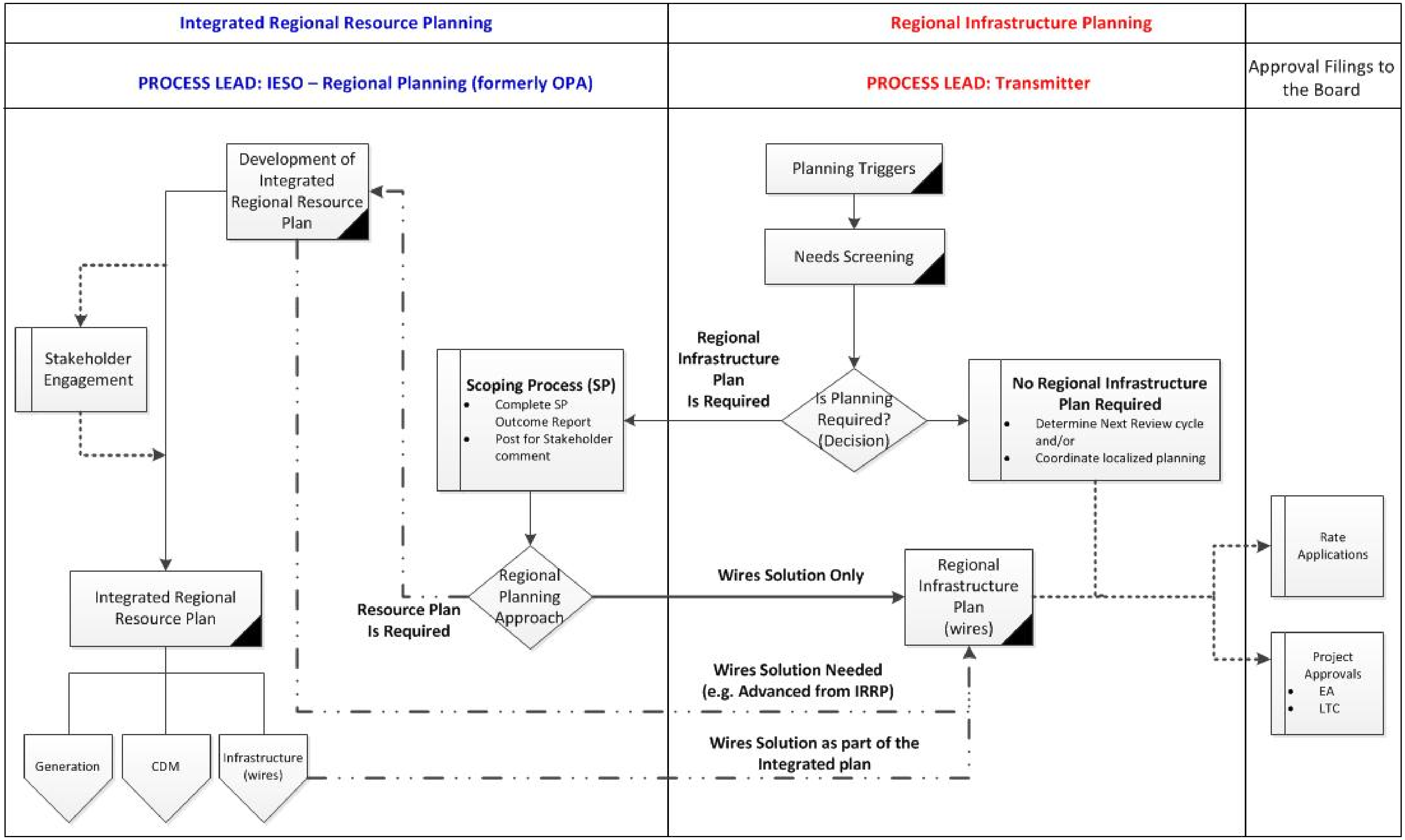

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

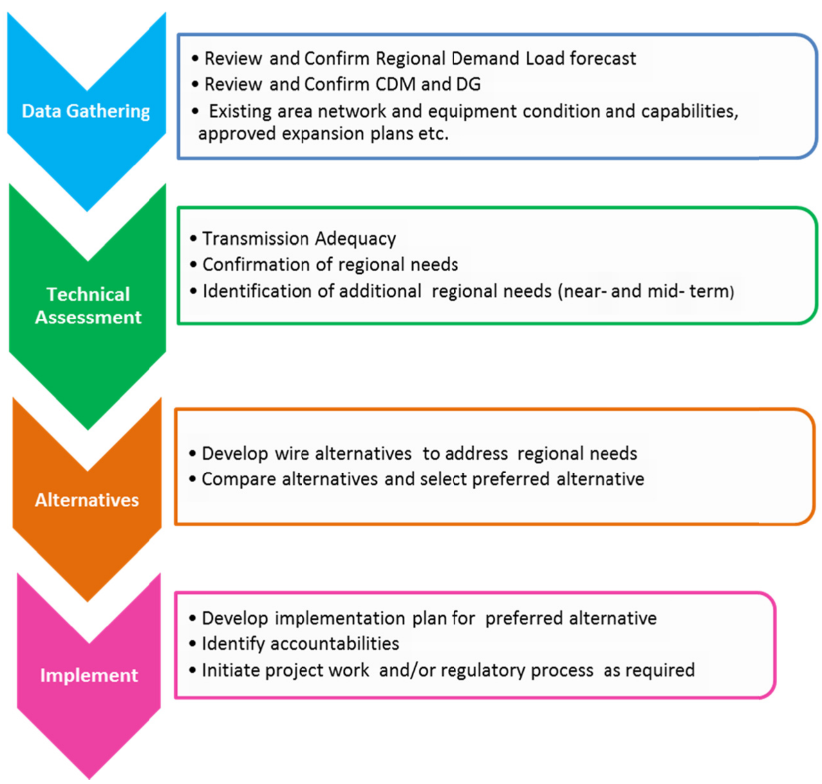

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GREATER OTTAWA REGION COVERS THE MUNICIPALITIES BORDERING THE OTTAWA RIVER FROM ARNPRIOR IN THE WEST TO HAWKESBURY IN THE EAST AND NORTH OF HIGHWAY 43. AT THE CENTER OF THIS REGION IS THE CITY OF OTTAWA (SEE FIGURE 3-1). ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIFTY-TWO 230 KV AND 115 KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1840 MW.

Bulk electrical supply to the Greater Ottawa Region is provided through the 500/230 kV Hawthorne TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. The area has been divided into two sub-regions as shown in Figure 1-1 and described below:

- The Ottawa Sub-Region comprises primarily the City of Ottawa. It is supplied by two 230/115 kV autotransformer stations (Hawthorne TS and Merivale TS, eight 230 kV and thirty-three 115 kV transformer stations stepping down to a lower voltage. Local generation in the area consists of the 74 MW Ottawa Health Science Non-Utility Generator ("NUG") located near the downtown area and connected to the 115 kV network. The Ottawa Sub-Region is shown in Figure 3-1 below.

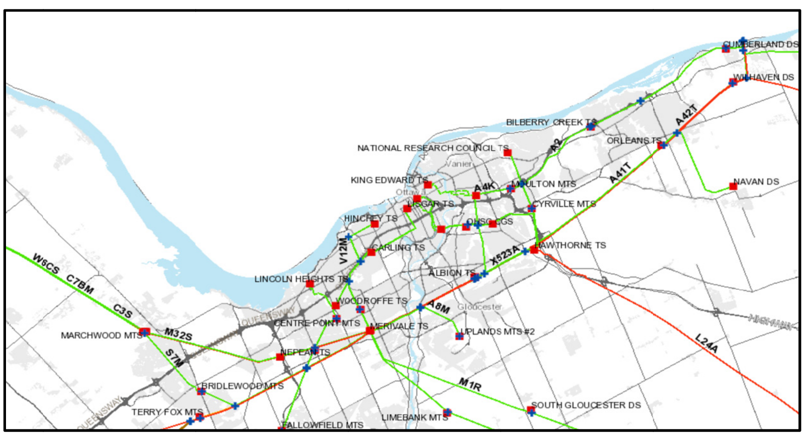

Figure 3-1 Ottawa Sub-Region

Hydro Ottawa is the main LDC that serves the electricity demand for the City of Ottawa. Hydro One Distribution supplies load in the outlying areas of the sub-region. Both Hydro Ottawa and Hydro One Distribution receive power at the step-down transformer stations and distribute it to the end users, i.e. industrial, commercial and residential customers.

- The Outer Ottawa Sub-Region covers the remaining area of the Greater Ottawa Region. The eastern area (shown in Figure 3-2) is served by three 230 and five 115 kV step-down transformer stations. Hydro One Distribution and Hydro Hawkesbury are the LDCs in the area that distribute power from the stations to the end use customers. It also includes a large industrial customer, Ivaco Rolling Mills, in L'Orignal, Ontario.

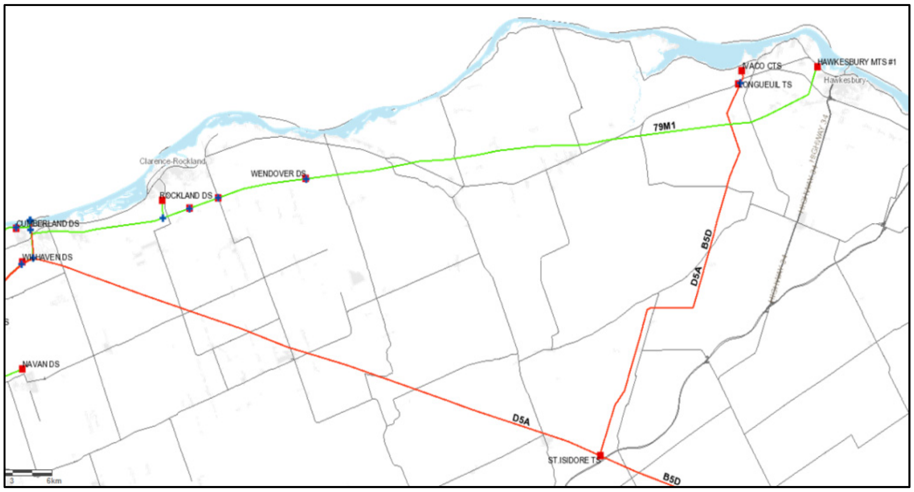

Figure 3-2 Outer Ottawa Sub-Region, Eastern Area

The western area of the Outer Ottawa Sub-Region is served by one 230 kV and two 115 kV step-down transformer stations. Hydro One Distribution is the LDC that supplies end use customers for these stations. The area includes the following generating stations: Barrett Chute GS, Chats Falls GS and Stewartville GS with a peak generation capacity of about 450 MW.

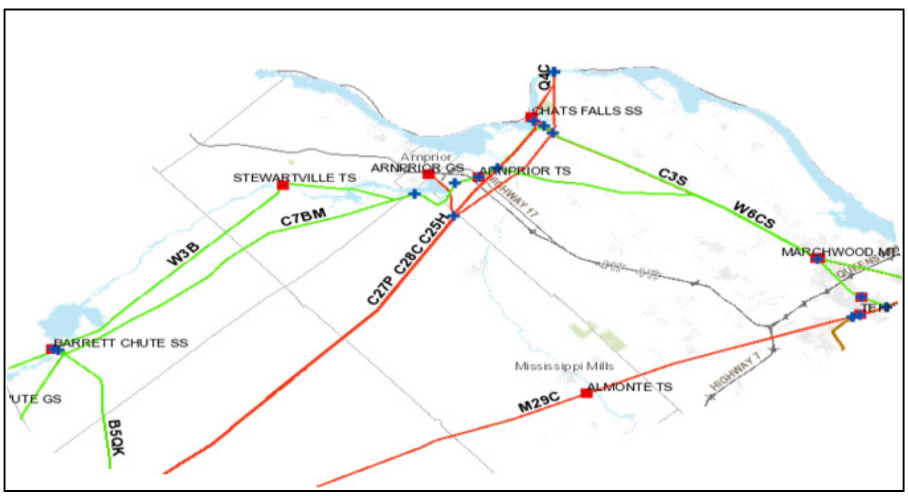

Figure 3-3 Outer Ottawa, Western Area

An electrical single line diagram for the Greater Ottawa Region facilities is shown in Figure 3-4.

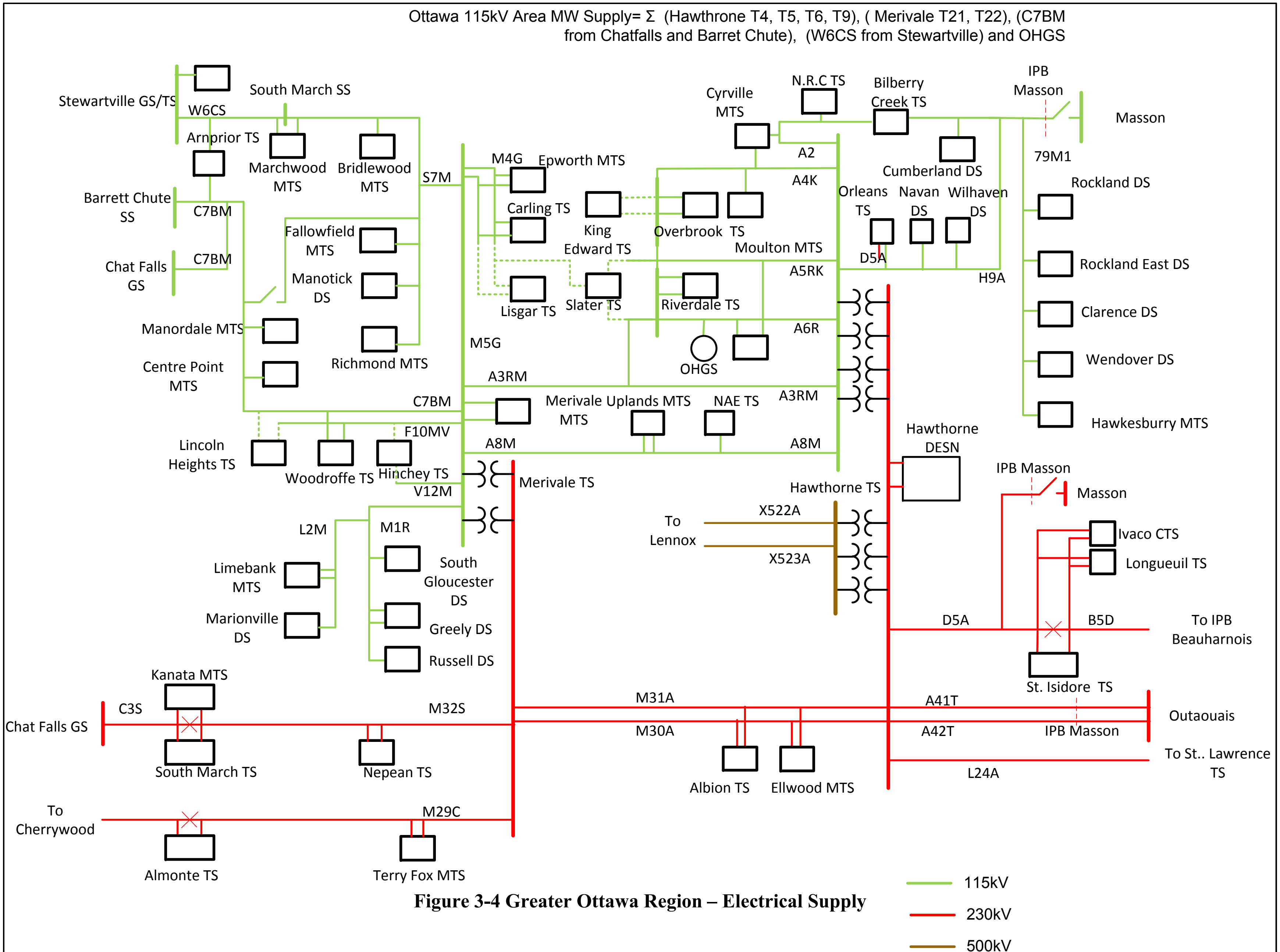

Figure 3-4 Greater Ottawa Region – Electrical Supply

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4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GREATER OTTAWA REGION IN GENERAL AND THE CITY OF OTTAWA IN PARTICULAR.

These projects were identified as a result of either: joint Hydro One, IESO and Hydro Ottawa planning studies to meet the needs of Hydro Ottawa or Hydro One Distribution; and/or, to meet provincial government policies. A brief listing of the completed projects over the last 10 years is given below:

- Hawthorne TS x Gamble Junction double circuit 230 kV Overhead line (2008) – the single 115 kV circuit H9A was rebuilt as a two circuit 230 kV tower line with increased capacity. Connect Cyrville MTS (2008) – connected new Hydro Ottawa owned Cyrville TS to 115 kV circuits A4K and A2.
- Hawthorne TS x Outaouais TS double circuit 230 kV line (2009) – built to provide up to 1250MW of transfer capability with Hydro Quebec as part of the new HVDC interconnection.
- Connect Ellwood MTS (2012) – connected new Hydro Ottawa owned Ellwood TS to 230 kV circuits M30A and M31A.
- Connect Terry Fox MTS (2013) – connected new Hydro Ottawa owned Terry Fox MTS to 230 kV circuit M29C.
- Hawthorne TS 115 kV switchyard Upgrade (2014) – replaced 115 kV breakers with inadequate short circuit capability with new breakers of higher short circuit capability. This work improved system reliability by allowing 115kV switchyards to be operated with bus tie closed. This work also facilitated incorporation of DG in the Ottawa area.
- Build new Orleans TS (2015) – built a new step-down transformer station in East Ottawa supplied from 230 kV circuit D5A and 115 kV circuits H9A. This station will provide additional load meeting capability to meet Hydro One Distribution and Hydro Ottawa requirements. It will also provide improved reliability for Hydro One Distribution customers in the Orleans-Cumberland area.
- Hinchey TS (2015) – Connect idle winding of transformer T1/T2 to new Hydro Ottawa metalclad switchgear.

The following projects are currently underway:

- Add 230 kV inline breaker on 230 kV circuit M29C at Almonte TS (2015) – to improve reliability of supply for Almonte TS and Terry Fox MTS.
- Replace 45/75 MVA, 115/13.2 kV step down transformers with new 60/100 MVA, 115/13.2 kV at Overbrook TS (2017) – the existing transformers are at end-of-life and the new replacement transformers have a higher rated capacity and will provide additional load meeting capability.

- Replace 225 MVA, 230/115 kV autotransformers T5 and T6 at Hawthorne TS with new 250 MVA, 230/115 kV autotransformers (2018) – the existing transformers have inadequate capacity and were identified and recommended for replacement during the IRRP phase for the Ottawa Sub-Region [1].
- Replace 50/83 MVA, 230/44 kV step down transformers with new 75/125 MVA, 230/44 kV units at Hawthorne TS (2019) – the existing transformers are at end-of-life and the new replacement transformers have a higher rated capacity and will provide additional load meeting capability.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Greater Ottawa Area is forecast to increase at an average rate of approximately 2.25% annually up to 2020, at 0.96% between 2020 and 2025 and at 0.45% beyond 2025. The growth rate varies across the Region with most of the growth concentrated in the Ottawa Sub-region.

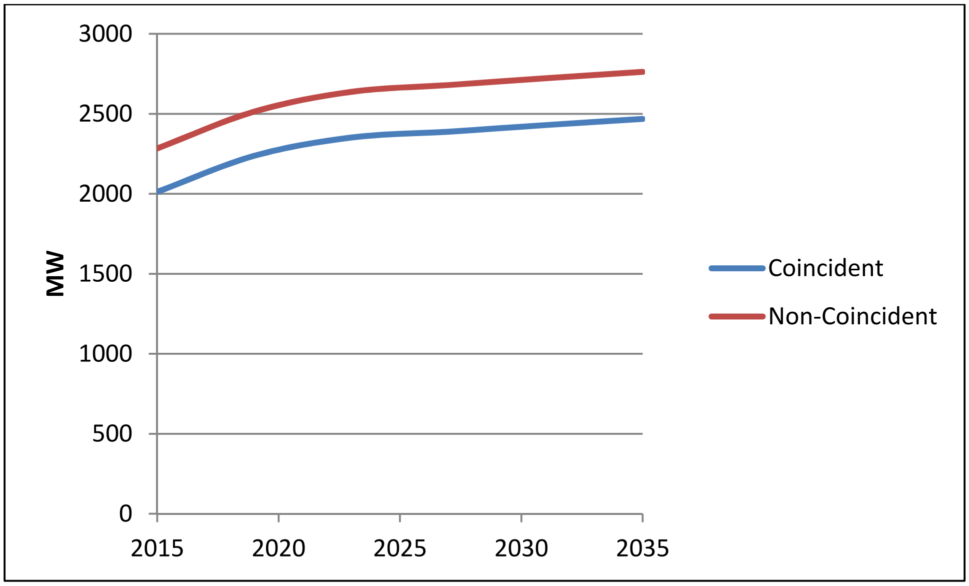

Figure 5-1 Greater Ottawa Region Summer Extreme Weather Peak Forecast

Figure 5-1 shows the Greater Ottawa Region extreme weather peak summer coincident and non-coincident load forecast. The coincident forecast represents the sum of the peak load at the time of the region's peak load and represents loads that would be seen by the autotransformer stations and is used to determine the need for additional auto-transformation capacity. The non-coincident forecast represents the sum of the individual stations peak load and is used to determine the need for stations and line capacity. Coincident and Non-coincident load forecasts for the individual stations in the Greater Ottawa Region are given in Appendix A.

The RIP load forecast was developed as follows:

- RIP Working Group participants confirmed that the load forecast, CDM, and DG information used in the IESO's 2015 IRRP for the Ottawa Sub-Region[1] and Hydro One's 2014 NA [2] was still valid and there were no changes.
- The station coincident loads used in the RIP are as given in the IRRP for Ottawa Sub-Region and NA for the Outer Ottawa Sub-Region. The coincident loading is used for evaluating the adequacy of bulk transmission circuits and the 230/115kV autotransformers.

- Stations non-coincident load forecast was developed using the summer 2015 actual peak load adjusted for extreme weather and applying the station net growth rates as identified in the IRRP and NA. The non-coincident forecast is used to determine adequacy of station capacity. The net growth rate accounts for CDM measures and connected DG. Details on the CDM and connected DG are provided in the IRRP [1] and NA for Ottawa Sub-Region [2] and are not repeated here.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP Assessments is 2015-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE GREATER OTTAWA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM. NO LONG TERM NEEDS HAVE BEEN IDENTIFIED.

Within the current regional planning cycle two regional assessments have been conducted for the Greater Ottawa Region. The April 2015 Ottawa Sub-Region IRRP report [1] was prepared by the IESO in conjunction with Hydro One and Hydro Ottawa. The July 2014 Outer Ottawa Sub-Region NA report [2] was prepared by Hydro One and considered the remainder of the Greater Ottawa region.

The IRRP [1] and NA [2] planning assessments identified a number of regional needs to meet the area forecast load demand over the near to mid-term between 2015 and 2025. These regional needs are summarized in Table 6.1 and include needs for which work is already underway and/or being addressed by an LP study. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the Greater Ottawa Region was also carried out as part of the RIP report. Sections 6.1 to 6.3 present the results of this review. Additional needs identified as a result of the review are also listed in Table 6-1.

Table 6-1 Near and Mid-Term Regional Needs

Type	Section	Needs	Timing(4)
Needs identified in IRRP [1] and NA [2]			
230/115kV Transformation Capacity	7.1	Hawthorne TS T5 and T6 – LTR(1) exceeded	2018(2)
	7.2.1	Merivale TS T22 - LTR(1) exceeded	2019
Transmission Circuit Capacity	7.2.2	S7M Circuit – Capacity	2019 and 2026
	7.3	A4K Circuit - Capacity	2019(2)
Station Capacity	7.4	Center 115kV Area - Capacity	2017-2021(3)
	7.5	Hawthorne TS T7 and T8 – LTR(1) exceeded	2019
	7.2.2	South West Area - Capacity	2020
	7.6	Bilberry Creek TS - Refurbishment	2023
Supply Security, Reliability and Restoration	7.7	Almonte TS/Terry Fox MTS - Reliability	2015
	7.8	Orleans TS - Reliability	No plan recommended(5)
	7.9	B5D+D5A Circuits – Restoration	No plan recommended(5)
	7.10	Load Loss for S7M Contingency	No plan recommended(5)
Voltage Regulation	7.11	79M1 Circuit – Voltage Regulation	2023
	7.12	Stewartville TS – Voltage Regulation	No plan recommended(5)
	7.13	Almonte TS/Terry Fox MTS –Voltage Regulation	No plan recommended(5)
	7.14	Almonte TS – Low Power Factor	No plan recommended(5)
Additional Needs identified in RIP			
	7.2.1	Merivale TS T22 and Hawthorne TS T9 – Continuous ratings exceeded	2024/25
	7.4.2.4	King Edward TS – Capacity	2021

(1) LTR – Limited time ratings to accommodate emergency loading for a short time under contingency conditions
(2) Projects have been initiated.
(3) Miscellaneous stations. Some are already in execution.
(4) Timing shows the proposed in service date for project underway, and the need date for the projects not yet started.
(5) Review did not recommend plan for mitigation. Please see the need details in Section 7.

6.1 500 and 230 kV Transmission Facilities

All 500 kV and 230 kV transmission circuits in the Greater Ottawa Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system and to the Hydro Quebec transmission system. A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfers as well as local area loads. These circuits are as follows (refer to Figure 3-4):

1. Hawthorne TS to Merivale TS 230 kV transmission circuits M30A/M31A – supply Albion TS and Ellwood TS.
2. Hawthorne TS to Cornwall 230 kV transmission circuits D5A/B5D/B31L – supply Orleans TS, St. Isidore TS and Longueuil TS. Also connects to Hydro Quebec at Beauharnois Station and to Lievre Power at Masson GS.
3. Merivale TS to Chats Falls 230 kV transmission circuits M32S/C3S – supply Nepean TS, South March TS and Kanata MTS
4. Merivale TS x Cherrywood TS 230 kV transmission circuits E29C/E34M (M29C) – supply Terry Fox MTS and Almonte TS.

Based on current forecast station loadings and bulk transfers, the M30A/M31A circuits will require reinforcement by 2020. The M30A/M31A upgrade will be addressed by Hydro One based on the recommendation stemming from an IESO Bulk System Planning study [6]. All other 230 kV circuits are expected to be adequate over the study period.

6.2 230/115 kV Transformation Facilities

Almost sixty percent of the Region load is supplied from the 115 kV transmission system. The primary source of 115 kV supply is from 230/115 kV autotransformers at Hawthorne TS and Merivale TS. Additional support is provided from 115 kV generation at Barrett Chute GS, Stewartville GS, part of Chats Falls GS, and the Ottawa Health Science NUG and the Ottawa River generation at Chaudière. Support from DG and CDM was considered as part of the load forecast.

Table 6-2 summarizes the results of the adequacy studies and gives the need dates for reinforcement of the 230/115 kV autotransformer facilities at Hawthorne TS and Merivale TS. Assuming no change in the system configuration, the forecasted loading will result in the Limited Time Rating ("LTR") of the Merivale autotransformer being exceeded by 2019 and the continuous rating of the Merivale and Hawthorne autotransformers by 2024/25.

The need dates are sensitive to the availability of hydraulic generation from Barrett Chute GS, Stewartville GS and Chats Falls GS and are based on 98% dependable generation availability as per ORTAC criteria. This corresponds to about 18 MW of available generation. A higher level of generator output from these stations would defer the need dates.

The need dates assume that the Hawthorne TS 225 MVA, 230/115 kV autotransformers T5 and T6 have been replaced with new 250 MVA units. The T5 and T6 replacement work is underway and is therefore not identified in the table below.

Table 6-2 Adequacy of 230/115 kV Autotransformer Facilities

Overloaded Facilities	2015 MVA Loading	MVA Load Meeting Capability	Limiting Contingency	Need Date
Merivale TS 230/115kV autotransformer T22	261	312[1]	T21	2019
Merivale TS 230/115kV autotransformer T21	182	250	[2]	2024
Hawthorne TS 230/115kV autotransformer T9	189	250	[2]	2025

[1] Limited time rating exceeded.

[2] Continuous rating exceeded with all elements in service based on existing system configuration

6.3 115 kV Transmission Facilities

The Greater Ottawa Region 115 kV transmission facilities can be divided in five main sections: Please see Figure 3-4 for the single line diagram.

1. Hawthorne 115 kV Center – has four circuits A3RM, A4K, A5RK and A6R. Reinforcement is required for the A4K circuit as a loss of the A5RK circuit would result in the loading exceeding the rating on the A4K circuit between Hawthorne TS and Moulton MTS (for details see Section 7.3).
2. Hawthorne 115 kV East – has two circuits A2 and H9A/79M1. These are expected to be adequate over the study period.
3. Merivale 115 kV Center – has two circuits M4G and M5G. These are expected to be adequate over the study period.
4. Merivale 115 kV West – has five circuits C7BM, F10MV, S7M, V12M and W6CS. Upgrading is required of the S7M tap to Fallowfield TS since forecasted loading will exceed circuit continuous rating (for details see section 7.4)
5. Merivale 115 kV South – has two circuits L2M and M1R. These circuits are adequate for the study period.

The loading on the limiting sections is summarized in Table 6-3.

Table 6-3 Adequacy of 115 kV Circuits

Corridor	Section	Overloaded Circuit	Rating (A)	Contingency	2015 Loading (A)	Need Date
1. Hawthorne TS x Blackburn Jct. x Overbrook TS	Hawthorne TS x Moulton TS	A4K	1070	A5RK	1006	2017
4. S7M tap to Fallowfield MTS	STR R14-R15 x Fallowfield Jct.(2)	S7M	590	All facilities in-service(1)	278	2024

(1) Continuous rating exceeded.
(2) Please see Figure 7-4.

6.4 Step-Down Transformation Facilities

There are a total of fifty-two step-down transmission connected transformer stations in the Greater Ottawa Region. The stations have been grouped based on the geographical area and supply configuration. The non-coincident station loading in each area and the associated station capacity and need date for relief is provided in Table 6-4 below. As shown areas requiring additional transformation capacity are the Center 115kV area, the South West 115kV area and the South 115kV area. Table 6-5 shows the non-coincident station loads for all areas which are adequate over the 2015-2025 study period. Details of the areas and associated stations are given in Appendix B.

Table 6-4 Adequacy of Step-Down Transformer Stations - Areas Requiring Relief

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
Center 115	569(1)	516	2018
South West 115	70	60	2019
South 115	182	151	2024

(1) With Overbrook TS 45/75 MVA transformers replaced with larger 60/100 MVA units.

Table 6-5 Adequacy of Step-Down Transformer Stations – Areas Adequate

Area/Supply	Capacity (MW)	2015 Loading (MW)	2025 Loading (MW)
East 115	340	231	229
West 115	504	351	425
Center 230/13.2kV	147	121	126
Center 230/44kV	153[(1)]	103	136
West 230	397	382	389
Outer East 115	80	56	62
Outer West 115	106	83	96
Outer East 230	149[(2)]	92	90
Outer West 230	100	48	45

(1) With Hawthorne TS 50/83 MVA transformers replaced with larger 75/125 MVA size units.

(2) Includes Longueuil TS and St Isidore TS load.

7. REGIONAL PLANS

This section discusses needs, presents wires alternatives and the current preferred wires solution for addressing the electrical supply needs for the Greater Ottawa Region. These needs are listed in table 6-1 and include needs previously identified in the IRRP for the Ottawa Sub-Region [1] and the NA for the Outer Ottawa Sub-Region [2] as well as the adequacy assessment carried out as part of the current RIP report.

7.1 Hawthorne Autotransformer T5 and T6

7.1.1 Description

Hawthorne TS is a major supply point for the city of Ottawa (Figure 7 -1). The station has four 230kV/115 kV autotransformers. Two of these autotransformers, T5 and T6, have lower ratings, with 225 MVA continuous and 256 MVA LTR, respectively. Under contingency conditions, i.e. one of the autotransformers out of service, the ratings of these two autotransformers are exceeded and this limits the supply to the 115 kV network from the 230 kV system. As the load continues to grow on the 115 kV network, this limitation needs to be addressed. This had been identified as a near term need in the Ottawa Sub-Region IRRP [1] and was included in the Ontario Power Authority's ("OPA", now part of IESO) June 2014 letter to Hydro One [5].

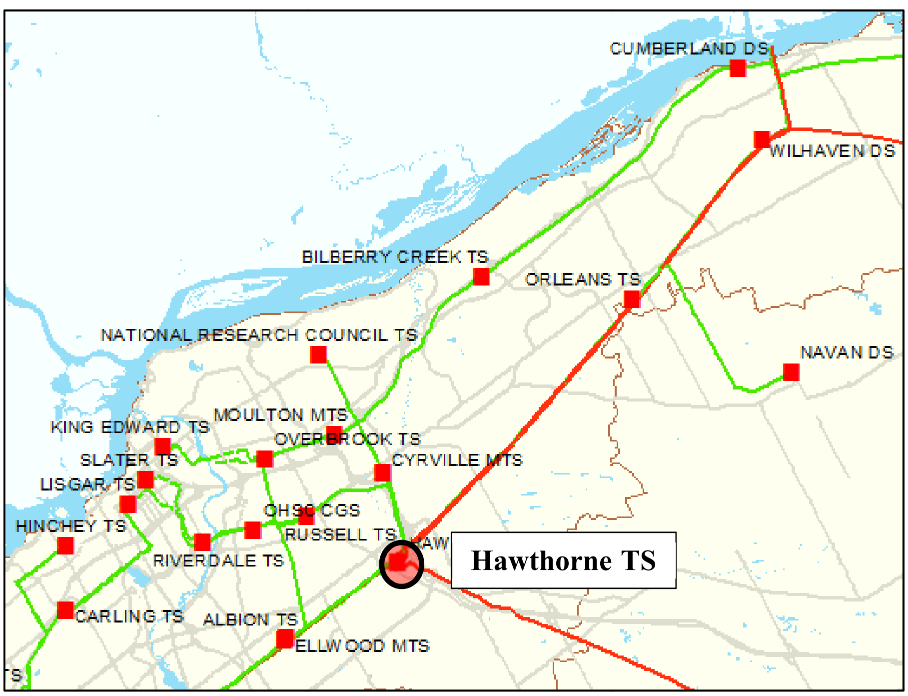

Figure 7-1 Hawthorne TS

7.1.2 Recommended Plan and Current Status

Hydro One has established a project to replace autotransformers T5 and T6 with new higher rated autotransformers. These autotransformers will have an LTR of at least 350 MVA. This investment will provide additional capacity and meet the needs of the area. It is expected that the project will be completed in 2018.

The cost of this project is expected to be $15.7 million. The project will be a transmission pool investment as the autotransformers provide supply to all customers in the Greater Ottawa Region.

7.2 Autotransformation Capacity and South West Area Station Capacity

7.2.1 Merivale TS Autotransformers T21 and T22/Hawthorne Autotransformer T9

Merivale TS has two 230 kV/115 kV autotransformers with an LTR station capacity of 312 MVA. The station is supplied from Hawthorne TS and from generators located west of Ottawa, along the Ottawa River and the Madawaska River. Merivale TS is shown in Figure 7-2.

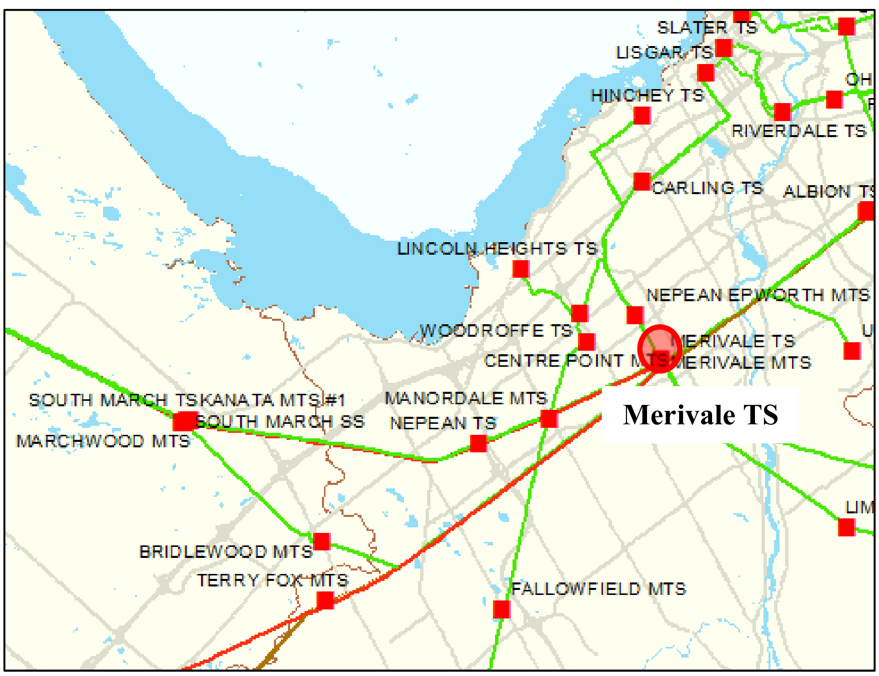

Figure 7-2 Merivale TS

The expected load growth provided by the LDCs and the minimum hydro generation assumption described in Section 6.2 causes the station capacity to be exceeded under contingency conditions by 2019. In addition, it is expected that autotransformers at Merivale TS and Hawthorne TS will reach their continuous loading limits of 250 MVA by 2024 and 2025. The exact timing of the autotransformer needs is dependent on the following factors:

- The South West area load forecast includes a proposed connection of a single large load increase coming into service in 2019.
- The need date is sensitive to generation at Stewartville GS, Barrett Chute GS and Chats Falls GS as its effect is to reduce the flow through the autotransformers.
- A potential solution to the need for additional supply capacity in the South West Area is a new 230 kV supply station which would remove some of the demand growth and existing load from the 115 kV network (see Section 7.2.2 for a complete description of this issue). This work would also help defer the need for additional autotransformer capacity at Merivale TS.

In order to address the Merivale TS autotransformer capacity concerns, additional 230/115 kV transformation capacity or load transfer from the 115 kV to the 230 kV system is required.

The provision of additional transformation capacity requires replacing the Merivale TS T22 autotransformer with a newer higher rated transformer in 2019 and adding a third autotransformer at the station in 2024. Alternatively a third transformer can be added at Merivale TS by 2019. To meet the required 2019 need date a decision on the autotransformer work is required by summer 2016.

Transferring load to the 230kV system requires establishing a new 230/27.6kV transformer station in the South West area to pick up some of the existing load and all of the new load growth. This is described in the following section.

7.2.2 Supply to South West Area – Line and Station Capacity

The South West area is served by Fallowfield MTS, Richmond MTS and Manotick DS connected to the 115kV circuit S7M out of Merivale TS. Load demand in the area is expected to increase by 52 MW in the next 10 years and both the line and station capacity are forecast to be exceeded by 2019.

The line limitation was identified in the OPA's June 2014 letter [5] to Hydro One. A section of the S7M circuit between the main line at STR R14-R15 JCT and Fallowfield Junction (see Figure 7-3 below) had a capacity of 420A. Hydro One review of the line capacity showed that the line rating was limited to respect safety clearances due to an underbuilt distribution feeder at Fallowfield MTS. This issue has been resolved with Hydro Ottawa carrying out the necessary work to lower the distribution feeder and increase the transmission line clearance. The line rating has been increased to 590A and is now adequate to meet forecast load until 2026.

Additional transformation capacity is required in the South West Area and both Fallowfield MTS and Richmond DS require load relief. Hydro Ottawa is planning for a capacity increase at Richmond DS and potentially a new station to relieve Fallowfield MTS in the Barrhaven area.

The IESO has initiated a public engagement process to gather community input for a preferred supply plan for the area including consideration of the potential for incremental CDM and DG resources and/or transmission expansion in the form of a new TS. The IRRP [1] recommended that given the required timeline, it would be beneficial for early transmission planning options to be started in parallel to the engagement process, prior to completing the integrated plan.

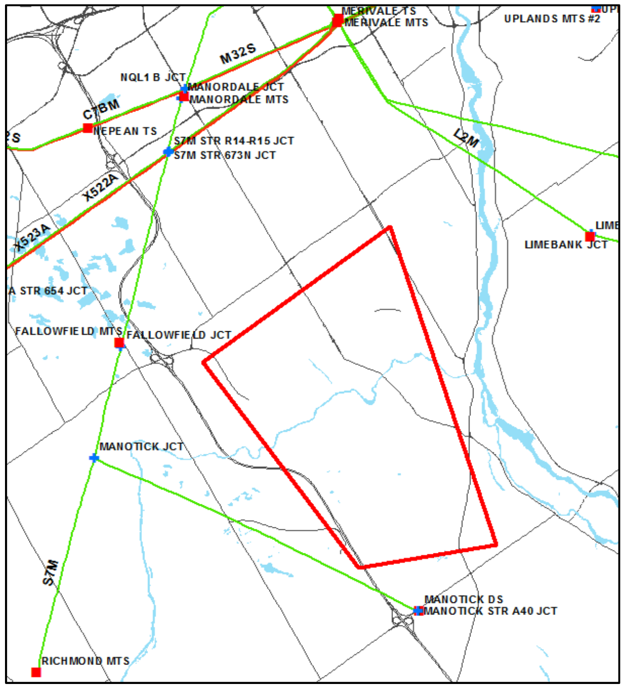

Figure 7-3 South West Area

At a high level, there are two main wire options to supply the South West area:

a) 115kV Option: Build a new 115/27.6kV transformer station and reinforce the existing 115 kV supply
b) 230kV option: Build a new 230/27.6kV transformer station and provide a new 230 kV transmission supply to the area.

The main advantage of the 115 kV option is that it defers the need for new transmission line until 2026. It however has a number of disadvantages: (a) loading will continue to increase on the 115kV system necessitating additional transformation capacity a Merivale TS by 2019 and Hawthorne TS by 2025, (b) all area stations remain on a single line supply until new transmission is built, and (c) the new 115 kV supply will provide less incremental capacity for the future.

The 230 kV option has the advantage of providing relief for the 230/115 kV autotransformers at Merivale TS and Hawthorne TS as well as provide more capacity to serve the area load. It also improves the area reliability by providing a second source of supply. The disadvantage is that transmission reinforcement will be required by 2019 and decision needs to be made as soon as possible.

The RIP has considered two options as examples for providing 230 kV supply to the area. Both examples consider building new double circuit 230 kV lines on existing Right of Way (“ROW”) in accordance with the provincial government policy to maximize ROW use. The two options are described below (also refer to Figure 7-3).

- *S7M Based Option - Rebuild S7M as a double circuit 230 kV line.*

  This option would require rebuilding the existing single circuit115 kV circuit S7M tap to Fallowfield MTS as a new double circuit 230 kV line. The line would extend from the S7M STR R14-R15 JCT (on the main line) to Manotick Jct. Depending on the station location, a part of S7M from Manotick JCT to Manotick DS would also have to be rebuilt for a total line rebuild of up to 15.5 km. One circuit would be operated at 115 kV and continue to supply Fallowfield MTS, Richmond DS and Manotick DS. The other circuit would be tapped off the 230 kV circuit M29C which is adjacent to S7M at STR R14-R15 JCT and will be used to supply the new Hydro Ottawa station. This option may require sections of the existing ROW to be widened to accommodate the 230 kV circuits. Additional real estate rights will have to be obtained. EA and OEB Leave to Construct (Section 92) approvals will also be required.

- *L2M Based Option - Rebuild L2M as a double circuit 230 kV Line*

  This option would require rebuilding the existing 115 kV circuit L2M from Merivale TS to past Limebank MTS as a new double circuit 230 kV line. This section of the line would be constructed using the existing L2M ROW for a distance of 8.5 km. A new 6-8 km long ROW would need to be acquired going west from the L2M ROW to bring the transmission line to the load area, crossing the Rideau River. One circuit on the new line would remain L2M and be operated at 115 kV. The other circuit would connect to circuit M32S at Merivale TS and be operated at 230 kV. The new station will be supplied from the 230 kV circuit.

7.2.3 Recommended Plan and Current Status

The needs for autotransformation capacity and a new station in south west are interrelated. Further analysis is required to determine the impact of the 230 kV supply options for the new south west station on the Merivale TS and Hawthorne TS autotransformers. The planning assessment will consider whether a 115kV supply to the new station in combination with the addition of an autotransformer at Merivale is more cost effective than a 230kV supply.

The IESO is currently carrying out community engagement activities in the Ottawa region. The Working Group will be discussing the supply options for the South West area in conjunction with the autotransformer upgrade work at Merivale TS and expect to recommend a preferred plan for the area by summer 2016.

7.3 115 kV Transmission Circuit A4K Supply Capacity

7.3.1 Description

Circuit A4K is a 115 kV circuit supplying four downtown stations: Overbrook TS, King Edward TS, Cyrville MTS and Moulton MTS. Loading on the A4K this circuit can exceed its rating under peak load conditions for loss of 115 kV circuit A5RK. This need was identified as a near term need in the Ottawa Sub-Region IRRP [1] and included in the OPA's June 2014 letter to Hydro One [5]. In this letter, the preferred plan to relieve circuit A4K is outlined. This plan consists of rebuilding an approximately 2 km long section of single circuit 115 kV circuit A5RK between Overbrook TS to Riverdale Jct. as a double circuit line (see Figure 7-4). One of the circuits would remain A5RK and the other would be tapped to circuit A6R. Overbrook TS will be reconfigured to be supplied from circuits A5RK/A6R instead A4K/A5RK. This reconfiguration would remove Overbrook TS load from 115 kV circuit A4K and eliminate the overloading on A4K for the loss of A5RK.

7.3.2 Current Status

Hydro One has initiated the development work for this line rebuild. The project is currently in the engineering and estimating phase. The project is not expected to require Leave to Construct (Section 92) approval, but will require Environmental Assessment ("EA") approvals.

The project is expected to be in service by spring 2019 and preliminary estimates suggest the cost to be approximately $9 million to $11 million. This work will be part of the Line Connection pool and costs will be recovered from the rate revenue and/or customer capital contribution in accordance with the TSC. As a result, the LDC may be required to make a capital contribution.

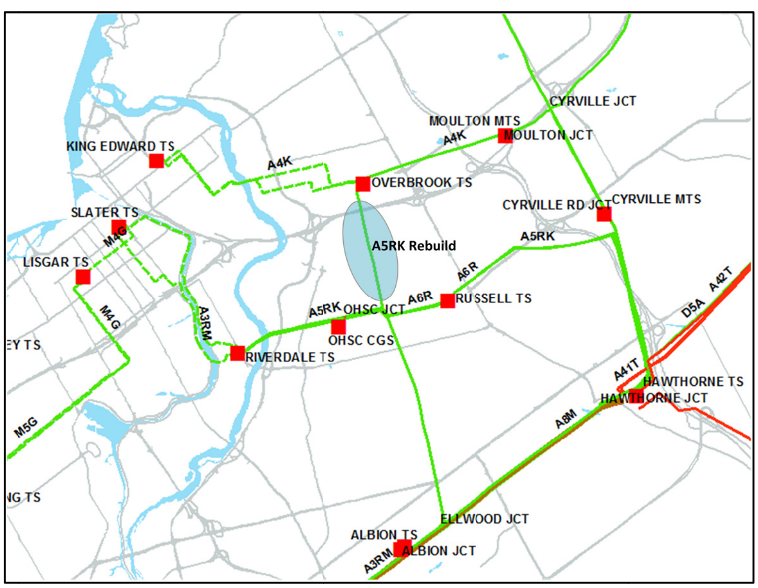

Figure 7-4 Option to Rebuild A5RK as Double-Circuit 115 kV Line

In the interim, Hydro One and Hydro Ottawa have operational mitigating measures to manage the overload on 115 kV circuit A4K if it becomes of concern before Hydro One has completed the line rebuild work. These measures include the transfer of Cyrville MTS to single supply from circuit A2 only by opening the A4K breaker at Cyrville MTS, and the transfer of some load from Moulton MTS to other stations in the area.

7.4 Station Capacity – Ottawa Centre 115 kV Area

7.4.1 Description

The Ottawa Center 115 kV area covers the City of Ottawa downtown district and extends from the Ottawa River in the north to Smyth Road in the south as shown in Figure 7-5 below. It is served by six 115/13.2 kV step-down transformer stations – King Edward TS, Lisgar TS, Overbrook TS, Riverdale TS, Russell TS and Slater TS. Most of the area stations are at or near capacity. Even with the Overbrook upgrade work now underway additional load meeting capability is forecast to be required by 2018 as shown in Table 6.3.

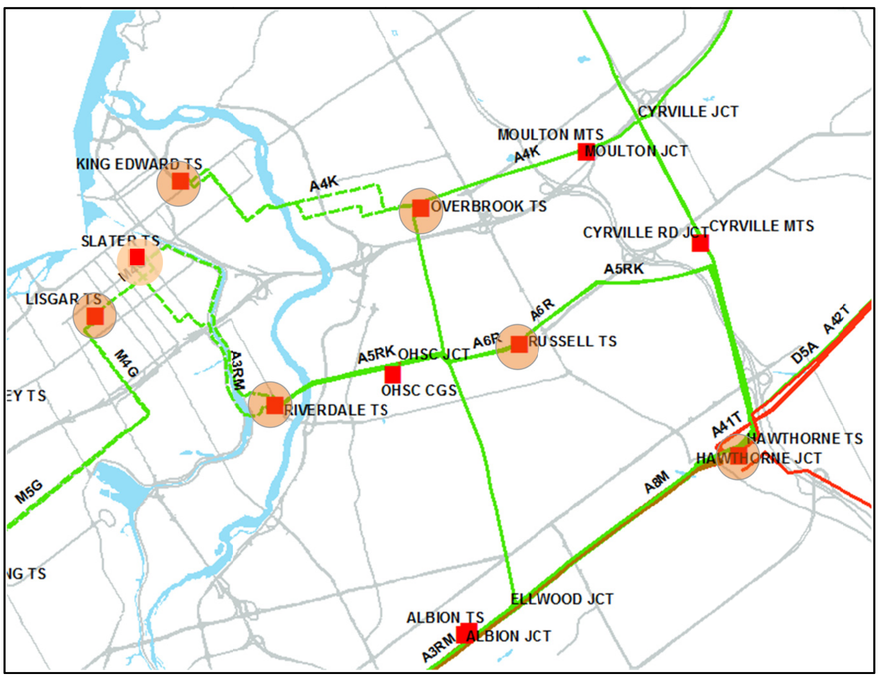

Figure 7-5 Downtown Ottawa Stations

7.4.2 Recommended Plan and Current Status

The existing step-down stations in the area are equipped with older 45/75 MVA transformers which have a LTR of between 70-80 MW. The preferred alternative to provide additional transformation capacity in the area is to replace these units with larger sized 100 MVA units where possible with an LTR of up to 130 MW.

During this regional planning cycle, the Working Group participants agreed to take advantage of transformer replacements necessitated by end-of-life considerations as this was the lowest cost and most practical option to provide additional capacity. The alternative of building a new station to provide capacity was ruled out because of the high cost and the difficulty in acquiring an appropriate site.

Upgrade of the end of life transformers at Overbrook TS is currently underway. In the future, the Working Group will continue to look for opportunities to upgrade based on end-of-life considerations of transformers. Hydro One will keep the Working Group informed of these opportunities. In addition, load transfers are also recommended to utilize available capacity at adjacent stations.

7.4.2.1 Russell TS and Riverdale TS

The loading on these stations will be kept within limits by Hydro Ottawa building feeder ties to transfer excess loads to other area stations. This will keep the loading on the transformers at these stations within their rating. A high level cost estimate of Hydro Ottawa's distribution work is $2 million.

7.4.2.2 Overbrook TS

Hydro One had identified that the step-down transformers at Overbrook TS were approaching end-of-life and consideration was therefore given to upgrading the transformers at the station. Accordingly Overbrook TS transformers are being replaced with larger sized units which will increase the station capacity from 72 MW to 130 MW. The work is underway and planned to be completed in Q2 2018. The incremental cost of upgrading to larger transformers is estimated to be $1.1 million. The cost of upgrading is expected to be recovered from incremental rate revenue in accordance with the TSC. Based on current forecast Hydro Ottawa is not expected to pay any capital contribution for this project.

7.4.2.3 Lisgar TS

Lisgar TS has two 75 MVA transformers. To meet the forecast load requirement additional transformation capacity is required in the Central 115kV area. Hydro Ottawa has therefore asked that the Lisgar TS transformers be replaced with larger 100 MVA units. The cost of the work is estimated to be about $14 million and will be recovered from rate revenue and customer capital contribution in accordance with the TSC. The target in-service date is Q4 2017.

7.4.2.4 King Edward TS

The capacity at King Edward TS is 71 MW. By replacing the limiting transformer T4 and additional low voltage ("LV") components such as circuit breakers and cable, a higher capacity of up to 130 MW can be achieved at King Edward TS.

Considering the Overbrook TS and Lisgar TS upgrades, adequate capacity will be available in the Center area until 2021. After discussion with Hydro Ottawa, the King Edward TS transformer upgrade work is tentatively scheduled for an in-service date of 2021. The project cost is estimated to be about $12M and will be recovered from rate revenue and customer capital contribution in accordance with the TSC.

7.5 Station Capacity - Hawthorne TS 44kV

Hawthorne TS has two 50/83 MVA, 230/44kV transformers with an LTR of 89 MW. Additional 44kV capacity is required at the station. Hydro One identified that the step- down transformers at Hawthorne TS were approaching end-of-life and needed to be replaced. The lowest cost alternative to provide this additional capacity was to take advantage of the transformer replacement work and install larger 75/125 MVA transformers with an LTR of 153 MW. This work is currently underway and planned to be completed by summer 2019.

Additional 44kV feeder positions will be required to utilize this increased capacity. These feeders will be added as required.

The incremental cost of upgrading to larger transformers is estimated to be approximately $1.1 million. Feeder position costs have not been estimated at this time. Incremental transformer costs and the feeder costs will be recovered in accordance with the TSC. Based on the current forecast Hydro Ottawa is not expected to pay any capital contribution for this project.

7.6 Bilberry Creek TS End of Life

7.6.1 Description

Bilberry Creek TS is a 115/27.6 kV step-down transformer in East Ottawa, supplying up to 85 MW of load customers to both Hydro Ottawa and Hydro One Distribution. The station was built in 1964 and a number of its key components have been identified for replacement by Hydro One. This station's refurbishment work is to be complete by 2023. A decision will be required by 2020 on whether to refurbish the station and keep the load on the 115 kV system or to retire the station and move the load over to the 230 kV system by supplying it from the newly built Orleans TS.

A Local Plan [3] carried out by Hydro One shows that the two options are similar in costs. The retirement option however, may be more attractive particularly if 115 kV load growth rate is high in the Ottawa Center area. The retirement option will reduce the loading of the 230 kV/115 kV autotransformers at Hawthorne TS and Merivale TS and make it available for the Ottawa Center 115 kV load. Figure 7-6 shows the area under consideration.

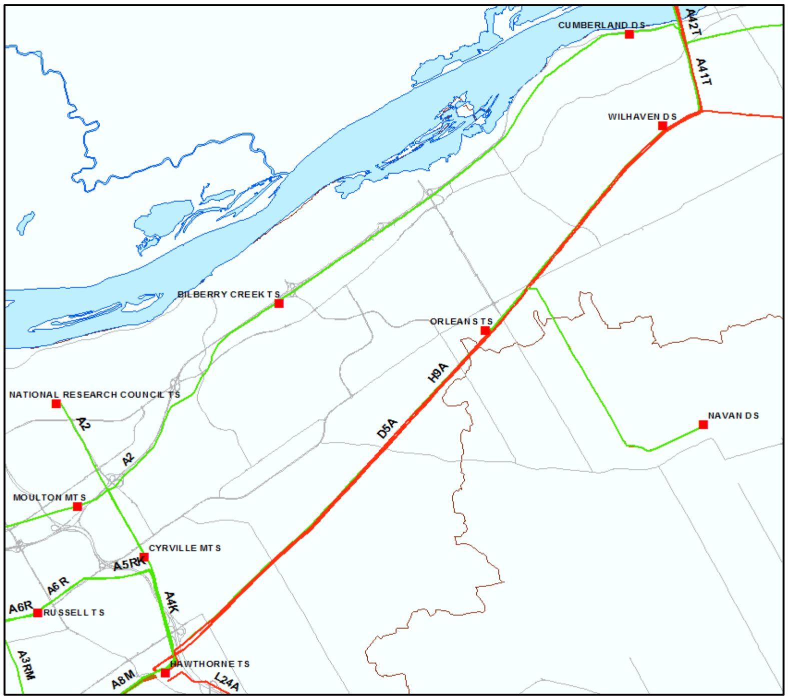

Figure 7-6 Bilberry Creek TS and the East Ottawa Area

7.6.2 Recommended Plan and Current Status

The two alternatives are very similar in cost and each has its own pros and cons. The refurbishment option minimizes work on the distribution system, but leaves the load on the 115kV system and with lower overall capacity to meet long term growth. The retirement option moves Bilberry Creek load to the 230kV system with higher long term load meeting capability but involves relocating distribution feeders from Bilberry Creek TS to Orleans TS.

The Working Group has recommended that a decision on Bilberry Creek refurbishment be deferred to the next regional planning cycle as there is still sufficient time to make an investment decision.

7.7 Almonte TS and Terry Fox TS Reliability

7.7.1 Description

Almonte TS and Terry Fox MTS are supplied from the 319 km long 230kV circuit M29C, see Figure 7-7. Due to the long length of the line the exposure to outages is high. The line has averaged approximately 6-7 interruptions per year over the last 10 years. With Terry Fox MTS coming into service in 2013, concerns were expressed about the number of outages that would be seen by the station. This issue was identified in the Ottawa Sub-Region IRRP [1] and the OPA’s June 2014 letter [5].

7.7.2 Recommended Plan and Current Status

Hydro One had initiated a project in 2012 to install a 230 kV circuit breaker at Almonte TS. This breaker would sectionalize the M29C line into two sections: E29C – 281 km Cherrywood TS to Almonte TS; and E34M – 38 km Almonte TS to Merivale TS. This breaker will help with the number of interruptions at Almonte TS and Terry Fox MTS by eliminating outages due to the Almonte TS x Cherrywood section of the circuit.

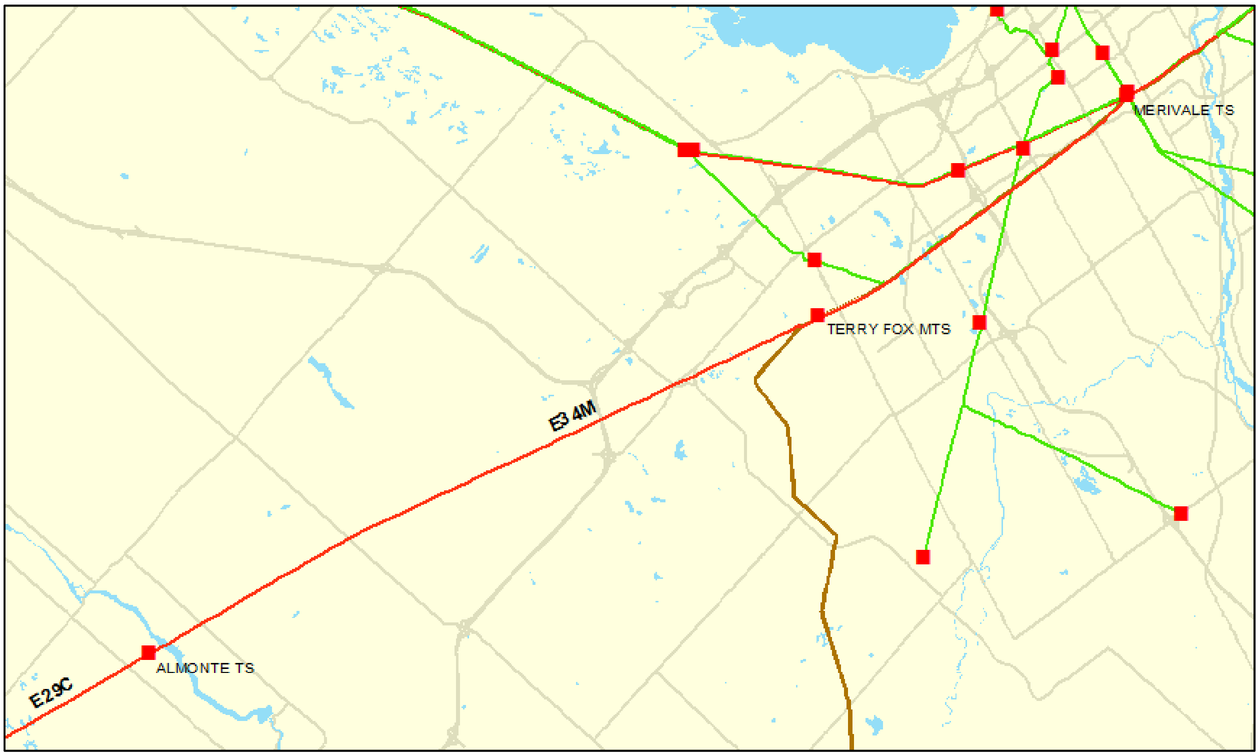

Figure 7-7 Lines E29C and E34M (M29C). In-Line Breaker at Almonte TS.

The total cost of this project is estimated to be $4.7 million and the project is scheduled to be completed by December 2015.

A second supply from Merivale TS to Terry Fox MTS was previously considered as an option to improve reliability. However it was decided to install the in-line breaker at Almonte TS since it was the cost effective and provided reliability improvement to both Almonte TS and Terry Fox MTS.

It should be noted that the Terry Fox TS is operated with the LV bus tie open. This arrangement has the disadvantage that in case of a transformer outage, the load connected to that transformer will be lost momentarily before the bus tie is closed to allow all loads to be supplied from the other side. A second supply to Terry Fox MTS can still be considered to address this issue as the load increases as part of a longer term supply plan. This will continue to be reviewed.

7.8 Orleans TS Reliability

7.8.1 Description

Orleans TS is a new station Hydro One built in East Ottawa to provide additional transformation capability and improve supply reliability for Hydro One Distribution customers connected to the 115 kV circuit H9A.

The Orleans TS is built adjacent to the double circuit H9A/D5A line about 10 km from Hawthorne TS and has one step-down transformer station supplied from 230 kV circuit D5A and the second step-down transformer supplied from the 115 kV circuit H9A. The station is operated with the LV bus tie open so as to avoid any power flow between the 230 kV and 115 kV systems through the station transformers. This arrangement has the disadvantage that in case of a circuit or transformer outage, the load connected to that circuit or transformer will be lost momentarily before the bus tie is closed to allow all loads to be supplied from the other side.

7.8.2 Recommended Plan and Current Status

Orleans TS has greatly improved the reliability of customers previous supplied from Wilhaven DS and Navan DS connected to 115kV circuit H9A. The customers experienced sustained interruptions every time circuit H9A had an outage. With the Orleans TS LV bus tie arrangement customer are exposed to a momentary interruption only as the load is picked up by closing the bus tie. This arrangement was accepted as a cost effective alternative to building 10 km of transmission line between Hawthorne TS and Orleans TS to provide a dual supply to Orleans TS.

Depending on the decision taken for Bilberry Creek TS described in section 7.6, Orleans TS could be converted to a 230 kV station and the LV bus tie closed. This option would be preferred if Bilberry Creek TS is recommended to be retired. If Bilberry Creek TS is refurbished then the plan will see Orleans TS continued operation with two different voltage supplies.

The Working Group recommendation is to monitor the performance of Orleans TS to see if mitigation measures are warranted. The Working Group will further review this issue in the next regional planning cycle as part of the Bilberry TS retirement study. No further action is required at this time.

7.9 Load Restoration for the Loss of B5D/D5A

7.9.1 Description and Current Status

The NA report for the Outer Ottawa Sub-Region [2] identified that the combined loss of circuits D5A and B5D would result in a load loss of up to 174 MW. The stations considered in this analysis are St Isidore TS, Longueil TS, and Ivaco CTS. Orleans TS is also supplied by D5A however; its second supply is H9A and is not considered for the combined loss of D5A/B5D. As indicated in ORTAC, any load lost above 150 MW must be restored within 4 hours and all load be restored within 8 hours.

A LP report [4] carried out by Hydro One shows that historically, the coincidental occurrence of forced sustained outages of B5D and D5A are rare and in all cases one of the circuits was restored in less than 4 hours as per ORTAC. The report concludes that no further action is required at this time.

7.10 Load Loss for S7M Contingency

7.10.1 Description and Current Status

Circuit S7M is the single supply for the following stations: Bridlewood MTS, Fallowfield MTS, Manotick DS, and Richmond DS. The combined load at these four stations is expected to exceed 150 MW by 2022. The ORTAC requires that not more than 150MW of load may be interrupted by configuration. However, given that the 150 MW limit is anticipated in the long term, no action is required at this time.

7.11 Voltage Regulation on 115kV Circuit 79M1

7.11.1 Description and Current Status

The 115 kV circuit 79M1 supplies Rockland DS, Rockland East DS, Clarence DS, Wendover DS, and Hawkesbury MTS. The NA for Outer Ottawa Sub-Region [2] identified that the voltage at Hawkesbury TS will approach operating limits under peak load and contingency conditions by 2023.

As mentioned in the Outer Ottawa Sub-Region NA report [2], Hydro One monitors the status of the network. Given the timing for this need, this will be reassessed during the next regional planning cycle.

7.12 Voltage at Stewartville TS

7.12.1 Description and Current Status

The load on the Stewartville TS is expected to increase significantly as a result of the connection of a large utility load forecasted for 2018. This load may require reactive support to help maintain the voltages within limits during peak load conditions and no generation at Stewartville GS.

A connection impact assessment will be undertaken by Hydro One as part of connecting the utility load. Any requirements to connect the load, including reactive power support, will be outlined in the document.

7.13 Voltage Drop at Terry Fox MTS for E34M open at the Merivale End

7.13.1 Description

Circuit E34M/E29C (new name for circuit M29C following the installation of a breaker at Almonte TS) is a 319 km line between Cherrywood TS in Pickering, and Merivale TS in Ottawa. If the circuit E34M (Almonte-Merivale) is open at the Merivale end, Terry Fox MTS and Almonte TS will be supplied radially by Cherrywood TS. Given the distance between the Greater Ottawa stations and Cherrywood TS, voltages are lower than acceptable limits during normal and peak load periods and only load of up to 25 MW can be supplied with acceptable voltage. The 2012 IESO System Impact Assessment ("SIA") recommended the installation of 20 MVARs of capacitor banks at Terry Fox MTS to meet a peak load of up to 48 MW.

7.13.2 Recommended Plan and Current Status

It is recommended that Hydro Ottawa install 20 MVARs of capacitor banks at Terry Fox MTS. This should be adequate for the near term.

Terry Fox MTS is part of the Ottawa Area under voltage load rejection scheme ("UVLS"). This scheme is designed to shed the station load if the 230 kV supply voltage to the station drops below 204 kV when it is activated. Currently the scheme is only armed when the entire Ottawa Area UVLS is armed. It is proposed to modify the scheme so that it can be selectively armed when loading levels are higher than 48MW and under conditions that may result in a circuit M29C line end open at Merivale TS.

Historically the probability of this line end open occurring is low and it would typically occur while terminal maintenance is done at Merivale. By scheduling maintenance during off peak periods, the impact can be significantly reduced. No mitigation measures are therefore recommended at this time. Hydro One and Hydro Ottawa will be monitoring the system performance and the matter will be reconsidered in the next planning cycle based on operating experience.

7.14 Low Power Factor at Almonte TS

7.14.1 Description and Current Status

The IESO's SIA for Almonte T3 replacement noted a low power factor at Almonte TS. This potential issue was also reported in the Outer Ottawa Sub-Region NA report [2].

Hydro One has reviewed the power factor at Almonte TS. The station power factor varies from 0.89 to 0.95 at the LV bus which translates into approximately 0.86 to 0.92 on the HV bus. Part of the reason for the lower power factor is that the station has 29 MW of DG which generally operates at unity power factor. The generation reduces the net power in MW seen at the metering point. This reduction in power results in a lower power factor as seen from the HV bus since the generation does not offset the reactive power demand of the station. No action is required as the load power factor without DG is within the acceptable limits.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GREATER OTTAWA REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses near term and mid-term regional needs identified in the earlier phases of the Regional Planning process and during the RIP phase. Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near term needs are summarized in the Table 8-1 below.

Investments to address the mid-term needs, for cases where there is time to make a decision, will be reviewed and finalized in the next regional planning cycle. These needs are summarized in Table 8-2.

No long term needs were identified at this time. As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years.. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

Table 8-1 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	I/S Date	Cost
1	Almonte TS: addition of breaker to sectionalize line M29C	Construction in the final stages	Hydro One	Dec. 2015	$4.7M
2	Russell TS and Riverdale TS: construction of feeder ties to allow extra load transfers	LDC will lead this work	Hydro Ottawa	2017-2020	$2.0M
3	Lisgar TS: replacement of transformers T1 and T2	Transmitter to carry out this work	Hydro One	Dec. 2017	$13.9M
4	Hawthorne TS: replacement of autotransformers T5 and T6	Transmitter to carry out this work	Hydro One	May 2018	$15.7M
5	Overbrook TS: replacement of transformers T3 and T4	Transmitter to carry out this work	Hydro One	June 2018	$1.1M(1)
6	A6R: additional tap to offload A4K	Transmitter to carry out this work	Hydro One	June 2019	$9-11M
7	Hawthorne TS: replacement of transformers T7 and T8 and add one 44kV feeder position	Transmitter to carry out this work	Hydro One	Oct. 2019	$1.1M(2)
8	New South West Station And Merivale 230/115kV Transformation Capacity	IESO and Hydro Ottawa leading consultation	IESO/Hydro Ottawa	2020	--- (3)
9	King Edward TS: Replace Transformer T4	Transmitter to carry out this work	Hydro One	June 2021	$12M

(1) Incremental cost for larger transformer only.
(2) Incremental cost for larger transformer only. Feeder costs have not been estimated at this time.
(3) The Working Group expects to make a final recommendation on this plan by early 2016.

Table 8-2 List of Mid-Term Needs to be Reviewed in Next Regional Planning Cycle

No.	Need	Timing
1	Bilberry Creek TS - Refurbishment	2023
2	Orleans TS - Reliability	2023[(1)]
3	79M1 Circuit – Voltage regulation	2023

(1) Performance will be monitored to see if mitigation measures are warranted. Need will be reviewed along with Bilberry Creek TS refurbishment.

9. REFERENCES

[1]. Independent Electricity System Operator, "Ottawa Area Integrated Regional Resource Plan", 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/Greater_Ottawa/2015-Ottawa-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, Greater Ottawa Region – Outer Ottawa Sub Region", 28 July 2014.
http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/Needs%20Assessment%20Report%20-%20Greater%20Ottawa%20-%20Outer%20Ottawa%20SubRegion.pdf

[3]. Hydro One, "Local Planning Report – Supply to East Ottawa Area", 26 November 2015.
http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/Local%20Planning%20Report%20-%20Supply%20to%20East%20Ottawa%20Area.pdf

[4]. Hydro One, "Local Planning Report - B5D-D5A Load Restoration", 22 September 2015.
http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/Local%20Planning%20Report%20-%20B5D-D5A%20Load%20Restoration.pdf

[5]. Hydro One, "OPA Letter – Ottawa Area Regional Planning", 27 June 2014.
http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/Letter%20to%20H1%20RE%20Ottawa.pdf

[6]. Independent Electricity System Operator, "Review of Ontario Interties", 14 October 2014.
http://www.ieso.ca/Documents/IntertieReport-20141014.pdf

APPENDIX A: STATIONS IN THE GREATER OTTAWA REGION

No.	Station	Voltage (kV)	Supply Circuits
1	Albion TS	230	M30A, M31A
2	Almonte TS	230	M29C (E34M, E29C)
3	Arnprior TS	115	W6CS, C7BM
4	Bilberry Creek TS	115	A2, H9A
5	Bridlewood MTS	115	S7M
6	Carling TS	115	M4G, M5G
7	Centrepoint MTS	115	C7BM
8	Clarence DS	115	79M1
9	Cumberland DS	115	H9A
10	Cyrville MTS	115	A2, A4K
11	Ellwood TS	230	M30A, M31A
12	Epworth MTS	115	M4G, M5G
13	Fallowfield DS	115	S7M
14	Greely DS	115	M1R
15	Hawkesbury MTS	115	79M1
16	Hawthorne	230	-
18	Ivaco	230	D5A
19	Kanata MTS	230	C3S, M32S
20	King Edward TS	115	A4K, A5RK
21	Limebank MTS	115	L2M
22	Lincoln Heights TS	115	C7BM, F10MV
23	Lisgar TS	115	M4G, M5G
24	Longueuil TS	115	B5D, D5A
25	Manordale MTS	115	C7BM
26	Manotick DS	115	S7M
27	Marchwood MTS	115	S7M, W6CS
28	Marionville DS	115	L2M
29	Merivale TS	115	-
30	Moulton MTS	115	A4RK
31	Nation Research TS	115	A2
32	National Aeronautical CTS	115	A8M
33	Navan DS	115	H9A
34	Nepean TS	115	M32S
35	Orleans TS	230 & 115	D5A, H9A
36	Overbrook TS	115	A4K, A5RK
38	Riverdale TS	115	A3RM, A5RK
39	Rockland DS	115	79M1
40	Rockland East DS	115	79M1

41	Russell DS	115	M1R
42	Russell TS	115	A5RK, A6R
43	Slater TS	115	A3RM, A5RK, M4G
44	South Gloucester DS	115	M1R
45	South March	230	C3S, M32S
46	St. Isidore TS	230	B5D, D5A
47	Stewartville TS	115	W3B, W6CS
48	Terry Fox MTS	230	M29C (E34M)
49	Uplands MTS	115	A8M
50	Wendover DS	115	79M1
51	Wilhaven DS	115	H9A
52	Woodroffe TS	115	C7BM, F10MV

APPENDIX B: TRANSMISSION LINES IN THE GREATER OTTAWA REGION

Location	Circuit Designations	Voltage (kV)
Hawthorne TS – Merivale TS	M30A, M31A	230
Hawthorne TS – St Isidore TS	D5A	230
Merivale TS – Almonte TS	E34C (formally M29C)	230
Merivale TS – South March TS	M32S	230
South March SS – Chats Falls SS	C3S	230
Hawthorne TS – Bilberry Creek TS	A2	115
Hawthorne TS - Merivale TS	A3RM, A8M	115
Hawthorne TS – Overbrook TS	A4K, A5RK	115
Hawthorne TS – Riverdale TS	A6R	115
Hawthorne TS – Hawkesbury MTS	H9A/79M1	115
Merivale TS – Chats Falls TS	C7BM	115
Merivale TS – Hinchey TS	F10MV, V12M	115
Merivale TS – Lisgar TS	M4G, M5G	115
Merivale TS – South March SS	S7M	115
Stewartville TS – South March SS	W6CS	115
Stewartville TS – Barrett Chute TS	W3B	115

APPENDIX C: DISTRIBUTORS IN THE GREATER OTTAWA REGION

Distributor Name	Station Name	Connection Type
Hydro 2000	Longueuil TS	Dx
Hydro Hawkesbury	Hawkesbury MTS	Tx
	Longueil TS	Dx
Hydro One	Almonte TS	Tx
	Arnprior TS	Tx
	Bilberry Creek TS	Tx
	Clarence DS	Tx
	Cumberland DS	Tx
	Greely DS	Tx
	Hawthorne TS	Tx
	Longueil TS	Tx
	Manotick DS	Tx
	Marionville DS	Tx
	Navan DS	Tx
	Orleans TS	Tx
	Rockland DS	Tx
	Rockland East DS	Tx
	Russell DS	Tx
	South Gloucester DS	Tx
	St Isidore TS	Tx
	Stewartville TS	Tx
	Wilhaven DS	Tx
Hydro Ottawa	Albion TS	Tx
	Almonte TS	Dx
	Bilberry Creek TS	Tx
	Bridlewood MTS	Tx
	Carling TS	Tx
	Centrepoint MTS	Tx
	Cyrville MTS	Tx
	Ellwood MTS	Tx
	Nepean Epworth MTS	Tx
	Fallowfield DS	Tx
	Hawthorne TS	Dx, Tx
	Hinchey TS	Tx
	Kanata MTS	Tx
	King Edward TS	Tx

Hydro Ottawa	Limebank MTS	Tx
	Lincoln Heights TS	Tx
	Lisgar TS	Tx
	Manordale MTS	Tx
	Marchwood MTS	Tx
	Moulton MTS	Tx
	Merivale MTS	Tx
	Nepean TS	Tx
	Orleans TS	Tx
	Overbrook TS	Tx
	Richmond MTS	Tx
	Riverdale TS	Tx
	Russell TS	Tx
	Slater TS	Tx
	South Gloucester DS	Dx
	South March TS	Dx, Tx
	St Isidore TS	Dx
	Terry Fox MTS	Tx
	Upland MTS	Tx
	Woodroffe TS	Tx
Ottawa River Power Corporation	Almonte TS	Dx
Renfrew Hydro	Stewartville TS	Dx

APPENDIX D: AREA STATIONS LOAD FORECAST

Table D-1 Stations Coincident Load Forecast (MW)

Area	Station	LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Center 115	King Edward TS	71	70	67	69	75	75	75	76	77	78	77	77	78	77	77
	Lisgar TS	75	64	67	71	74	74	75	75	87	88	90	90	90	89	89
	Overbrook TS	130	85	91	94	100	101	102	108	110	111	112	113	114	115	116
	Riverdale TS	105	102	99	102	111	112	112	114	118	119	120	121	123	123	124
	Russell TS	69	61	63	65	73	73	73	73	73	73	73	73	73	73	73
	Slater TS	118	106	113	114	116	115	114	114	113	112	112	111	110	110	110
	Total	**569**	**488**	**501**	**515**	**549**	**549**	**550**	**559**	**578**	**581**	**584**	**586**	**588**	**589**	**590**
Center 230	Albion	88	71	72	73	73	73	73	74	74	75	75	76	77	77	77
	Ellwood TS	59	27	28	28	28	28	28	28	28	28	28	28	28	29	29
	Hawthorne	153	107	117	120	124	126	128	132	137	136	140	138	139	138	138
	Total	**300**	**206**	**217**	**221**	**225**	**227**	**229**	**234**	**239**	**239**	**243**	**243**	**244**	**243**	**243**
East 115	Bilberry Creek TS	85	87	54	54	54	54	54	54	54	55	55	55	55	55	56
	Cumberland DS	15	5	6	6	6	6	6	6	6	6	6	6	6	7	7
	Cyrville MTS	59	24	30	35	35	37	38	40	42	44	44	44	44	44	44
	Moulton MTS	34	31	32	32	32	32	32	32	33	33	33	33	34	34	34
	Nation Research TS	25	18	18	18	18	18	18	18	18	18	18	18	18	18	18
	Navan DS	15	6	6	6	6	6	6	6	6	6	6	6	5	5	5
	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Wilhaven DS	58	49	4	5	5	6	6	6	7	10	11	12	12	14	16
	Total	**340**	**221**	**193**	**201**	**202**	**205**	**208**	**210**	**215**	**221**	**224**	**226**	**228**	**232**	**237**
East 230	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Total	51	**0**	**45**	**46**	**46**	**47**	**48**	**48**	**50**	**50**	**51**	**52**	**54**	**55**	**57**
South 115	Greely DS	40	17	18	18	18	18	18	18	18	18	18	19	19	19	19
	Limebank MTS	68	44	47	49	52	54	56	59	64	70	76	82	89	88	88
	Marionville DS	28	13	14	14	14	14	14	14	14	14	14	14	15	15	15
	National Aeronautical CTS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Russell DS	8	3	3	3	3	3	3	3	3	3	3	3	3	3	4
	South Gloucester DS	8	4	4	4	4	4	4	4	4	4	5	5	5	5	5
	Uplands MTS	30	25	26	26	27	27	27	27	28	29	29	30	30	30	30
	Total	**182**	**109**	**112**	**115**	**118**	**121**	**123**	**126**	**133**	**140**	**147**	**154**	**161**	**161**	**161**
South West 115	Fallowfield DS	48	36	39	38	41	49	51	54	58	61	67	71	76	82	89
	Manotick DS	17	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Richmond DS	5	9	10	11	13	31	34	36	36	37	38	39	38	38	38
	Total	**70**	**52**	**56**	**56**	**61**	**87**	**92**	**97**	**101**	**106**	**112**	**118**	**122**	**127**	**134**

West 115	Bridlewood MTS	37	22	22	23	22	22	22	23	39	39	39	39	39	39	39
	Carling TS	93	82	83	84	85	86	86	87	93	95	96	98	99	100	102
	Centrepoint MTS	35	17	17	17	17	17	16	16	16	16	16	16	16	16	16
	Epworth	25	15	15	16	16	16	16	15	15	15	15	15	15	15	15
	Hinchey TS	77	58	60	62	66	68	70	72	67	71	75	79	83	87	90
	Lincoln Heights TS	71	45	45	45	45	44	44	44	49	49	49	48	48	48	48
	Manordale MTS	22	11	11	11	11	11	11	11	11	11	11	11	10	10	10
	Marchwood MTS	34	34	34	34	35	34	34	34	35	34	35	35	35	36	37
	Merivale TS	18	14	14	13	15	15	15	15	16	17	19	20	20	19	19
	Woodroffe TS	92	39	40	41	42	42	43	43	53	54	55	56	56	57	58
	Total	**504**	**336**	**340**	**346**	**353**	**355**	**356**	**362**	**395**	**402**	**410**	**417**	**421**	**427**	**434**
West 230	Kanata MTS	55	46	47	47	47	47	46	47	47	48	48	48	48	48	48
	Nepean TS	144	145	144	143	143	141	139	138	136	134	132	130	128	127	127
	South March	109	116	110	115	119	123	126	131	123	104	104	104	104	103	104
	Terry Fox MTS	90	39	50	78	83	65	65	64	63	63	62	61	60	60	60
	Total	**397**	**346**	**351**	**383**	**391**	**376**	**376**	**380**	**370**	**349**	**345**	**343**	**340**	**337**	**338**
Outer East 115	Clarence DS	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Hawkesbury MTS	18	15	15	15	15	15	15	15	15	16	16	16	16	16	16
	Rockland DS	9	8	8	8	8	8	8	9	9	9	9	9	9	9	9
	Rockland East DS	15	12	12	12	12	12	12	12	13	13	13	13	13	13	13
	Wendover TS	34	12	12	12	12	12	12	12	14	14	14	14	13	13	13
	Total	**80**	**49**	**49**	**50**	**50**	**50**	**50**	**51**	**55**	**55**	**55**	**55**	**55**	**55**	**56**
Outer East 230	Ivaco	100	40	40	40	40	40	40	40	40	40	40	40	40	40	40
	Longueuil TS	98	31	31	31	31	30	30	30	30	30	30	30	30	30	30
	St. Isidore TS	52	35	35	36	35	35	35	35	35	35	35	35	35	35	35
	Total	**249**	**106**	**106**	**106**	**106**	**106**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**
Outer West 115	Arnprior TS	51	36	36	36	36	35	35	35	34	34	34	34	34	34	34
	Stewartville TS	55	30	30	30	46	46	45	45	45	45	45	45	45	45	45
	Total	**106**	**66**	**66**	**66**	**82**	**81**	**80**	**80**	**79**	**79**	**79**	**79**	**79**	**79**	**79**
Outer West 230	Almonte TS	100	35	34	34	34	34	33	33	33	33	33	33	33	33	33
	Total	**100**	**35**	**34**	**34**	**34**	**34**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**
Regional Total		**2948**	**2013**	**2069**	**2140**	**2219**	**2238**	**2249**	**2285**	**2352**	**2360**	**2388**	**2411**	**2430**	**2445**	**2468**

Table D-2 Stations Non Coincident Forecast (MW)

Area	Station	LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Center 115	King Edward TS	71	88	84	87	93	93	93	94	96	97	97	96	97	96	96
	Lisgar TS	75	67	70	74	78	78	78	79	91	92	94	94	94	93	93
	Overbrook TS	130	84	91	93	99	100	102	107	109	110	111	112	113	114	115
	Riverdale TS	105	78	76	78	84	85	86	87	90	91	92	93	93	94	95
	Russell TS	69	74	77	80	90	89	89	89	89	89	89	90	90	90	90
	Slater TS	118	125	133	134	136	135	134	134	133	132	131	131	130	129	129
	Total	**569**	**516**	**530**	**546**	**580**	**581**	**581**	**590**	**608**	**612**	**614**	**615**	**617**	**617**	**619**
Center 230	Albion	88	77	79	80	80	80	80	80	81	82	82	83	84	84	84
	Ellwood TS	59	43	43	44	44	44	43	44	44	44	44	44	45	45	45
	Hawthorne	153	103	115	120	124	126	128	132	137	136	140	138	139	138	138
	Total	**300**	**223**	**238**	**243**	**248**	**250**	**251**	**256**	**262**	**262**	**266**	**266**	**267**	**266**	**267**
East 115	Bilberry Creek TS	85	87	54	54	54	54	54	54	54	55	55	55	55	55	56
	Cumberland DS	15	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Cyrville MTS	59	25	31	37	37	39	40	42	44	47	47	47	47	47	47
	Moulton MTS	34	40	40	40	41	40	40	41	41	41	42	42	42	43	43
	Nation Research TS	25	18	19	19	19	19	18	19	19	19	18	18	18	18	18
	Navan DS	15	6	6	6	6	6	5	5	5	5	5	5	5	5	5
	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Wilhaven DS	58	53	4	5	5	6	6	6	7	10	11	12	12	14	16
	Total	**340**	**231**	**200**	**208**	**209**	**212**	**215**	**217**	**223**	**229**	**231**	**234**	**236**	**240**	**244**
East 230	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Total	**51**	**0**	**45**	**46**	**46**	**47**	**48**	**48**	**50**	**50**	**51**	**52**	**54**	**55**	**57**
South 115	Greely DS	40	35	35	36	36	36	36	36	36	37	37	37	38	38	38
	Limebank MTS	68	47	49	52	54	56	59	61	67	73	79	86	93	92	92
	Marionville DS	28	31	31	31	32	32	31	32	32	32	33	33	33	34	34
	National Aeronautical CTS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Russell DS	8	12	13	13	13	13	13	13	13	13	13	13	13	13	13
	South Gloucester DS	8	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Uplands MTS	30	20	20	20	21	21	21	21	22	22	23	23	24	23	23
	Total	**182**	**151**	**155**	**159**	**162**	**165**	**167**	**171**	**178**	**185**	**193**	**201**	**209**	**209**	**209**
South West 115	Fallowfield DS	48	45	49	48	51	61	64	68	72	76	84	89	95	102	111
	Manotick DS	17	8	8	9	9	9	9	9	9	9	9	9	9	9	9
	Richmond DS	5	7	7	8	10	22	24	25	26	27	27	28	28	27	27
	Total	**70**	**60**	**64**	**65**	**69**	**92**	**97**	**102**	**107**	**112**	**120**	**126**	**131**	**139**	**147**

West 115	Bridlewood MTS	37	34	34	35	35	34	34	35	61	61	60	61	61	60	60
	Carling TS	93	88	89	90	91	92	92	93	100	102	103	105	106	107	109
	Centrepoint MTS	35	21	21	21	21	21	21	21	21	21	20	20	20	20	20
	Epworth	25	15	15	16	16	16	16	16	16	15	15	15	15	15	15
	Hinchey TS	77	47	49	51	54	55	57	59	54	57	61	64	67	70	73
	Lincoln Heights TS	71	48	48	48	48	47	47	47	53	52	52	52	51	51	51
	Manordale MTS	22	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	Marchwood MTS	34	35	35	35	36	35	35	36	36	36	36	36	36	37	38
	Merivale TS	18	18	19	18	20	20	20	20	22	23	26	27	26	26	26
	Woodroffe TS	92	35	36	36	37	38	38	39	47	48	49	49	50	51	51
	Total	**504**	**351**	**355**	**361**	**368**	**369**	**369**	**375**	**419**	**425**	**432**	**439**	**443**	**448**	**454**
West 230	Kanata MTS	55	87	88	88	88	88	87	88	89	89	90	90	90	90	90
	Nepean TS	144	153	152	151	150	148	146	145	144	141	139	137	135	133	133
	South March	109	98	93	97	101	104	107	110	102	87	87	87	87	86	87
	Terry Fox MTS	90	44	57	88	93	74	73	72	71	71	70	69	68	67	67
	Total	**397**	**382**	**390**	**424**	**432**	**414**	**412**	**416**	**406**	**389**	**385**	**383**	**379**	**377**	**377**
Outer East 115	Clarence DS	4	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Hawkesbury MTS	18	17	17	17	17	17	17	17	18	18	18	18	18	19	19
	Rockland DS	9	17	17	17	18	18	18	18	19	19	19	19	19	19	19
	Rockland East DS	15	11	11	11	12	12	12	12	13	13	13	13	13	13	13
	Wendover TS	34	9	9	9	9	9	9	10	11	11	11	10	10	10	10
	Total	**80**	**56**	**56**	**56**	**57**	**57**	**57**	**57**	**62**	**62**	**63**	**63**	**63**	**63**	**63**
Outer East 230	Ivaco	100	92	92	92	92	92	92	92	92	92	92	92	92	92	92
	Longueuil TS	98	44	44	44	44	43	43	43	43	43	43	43	43	43	43
	St. Isidore TS	52	48	48	48	48	47	47	47	47	47	47	47	47	47	47
	Total	**249**	**184**	**184**	**184**	**184**	**183**	**182**	**182**	**182**	**182**	**182**	**182**	**182**	**182**	**182**
Outer West 115	Arnprior TS	51	51	51	51	51	50	49	49	49	49	49	49	49	49	49
	Stewartville TS	55	32	32	32	49	49	48	48	48	48	48	48	48	48	48
	Total	**106**	**83**	**82**	**82**	**100**	**99**	**97**	**97**	**96**	**96**	**96**	**96**	**96**	**96**	**96**
Outer West 230	Almonte TS	100	48	48	47	47	47	46	46	45	45	45	45	45	45	45
	Total	**100**	**48**	**48**	**47**	**47**	**47**	**46**	**46**	**45**	**45**	**45**	**45**	**45**	**45**	**45**
Region Total		**2948**	**2284**	**2346**	**2421**	**2503**	**2514**	**2522**	**2558**	**2637**	**2650**	**2680**	**2702**	**2722**	**2738**	**2762**

APPENDIX E: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

GTA East

REGIONAL INFRASTRUCTURE PLAN

January 9th, 2017

hydro one

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Oshawa PUC Networks Inc.
Veridian Connections Inc.
Whitby Hydro Electric Corporation

DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS OF THE GTA EAST REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Oshawa PUC Networks Inc.
- Veridian Connections Inc.
- Whitby Hydro Electric Corporation
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB's mandated regional planning process for the GTA East Region which consists of the Pickering-Ajax-Whitby Sub-Region and the Oshawa-Clarington Sub-Region. It follows the completion of the GTA East Region's Needs Assessment ("NA") in August 2014, the Oshawa-Clarington Sub-Region's Local Plan ("LP") in May 2015, and the Pickering-Ajax-Whitby Sub-Region's Integrated Regional Resource Plan ("IRRP") in June 2016.

This RIP provides a consolidated summary of needs and recommended plans for the entire GTA East Region that includes the Pickering-Ajax-Whitby Sub-Region and Oshawa-Clarington Sub-Region. The major transmission and distribution infrastructure investments planned for the GTA East Region over the near and mid-term, as identified in the regional planning process are given below.

No.	Project	I/S Date	Cost
1	Enfield TS; new 230/44kV station	2019	$34M[1]
2	Seaton MTS; new 230/27.6/27.6kV station	2019	$43M-$48M[2]

As per the Regional Planning process, the Regional Plan will be reviewed and/or updated at least once every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

[1] Considers 6x44kV feeder breaker positions initially without capacitor banks
[2] Class Environmental Assessment (EA) not complete at time of RIP. Range of costs includes all sites under consideration – includes transmission line rebuild costs and all station equipment less capacitor banks for 12x27.6kV feeders and a spare transformer.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA EAST REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Hydro One Distribution, Oshawa PUC Networks Inc. ("OPUCN"), Veridian Connections Inc. ("Veridian"), Whitby Hydro Electric Corporation ("Whitby Hydro") and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, and Clarington. Electrical supply to the Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station ("TS") and five[3] 230kV transmission lines that supply the four local area step-down transformer stations. The boundaries of the Region are shown in Figure 1-1 below.

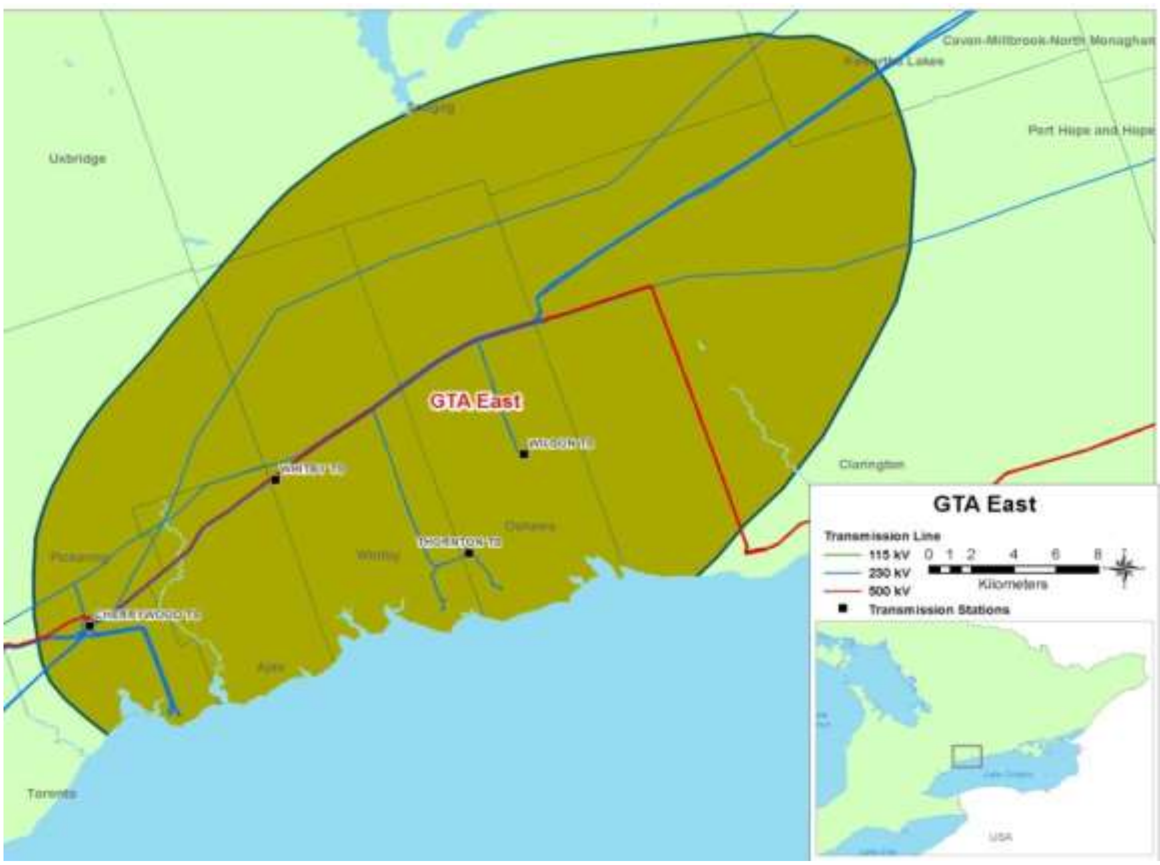

Figure 1-1 GTA East Region

[3] Including 230kV circuit C28C (T28C with Clarington TS) which extends 2km north from Cherrywood TS to Duffin Jct. and then extends 26km east to be terminated at Clarington TS in 2018

1.1 Scope and Objectives

This RIP report examines the needs in the GTA East Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plans to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2016-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2016-2025 period and a wires plan to address them;
- Consideration of long-term needs identified in the Pickering-Ajax-Whitby Sub-Region IRRP

As per the Regional Planning process, the Regional Plan for the region will be reviewed and/or updated at least every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the regional characteristics
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the regional needs
- Section 7 describes the needs and provides the alternatives and preferred solutions
- Section 8 provides the conclusion and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115kV and 230kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[4] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, and needs are local in nature, an assessment is undertaken for any necessary investments directly by the LDCs (or customer) and the transmitter through a Local Plan ("LP"). These needs are local in nature and can be best addressed by a straight forward wires solution. The Working Group recommends a LP undertaking when needs are a) local in nature b) limited investments of wires (transmission or distribution) solutions c) does not require upstream transmission investments d) does not require plan level stakeholder engagement and e) other approvals such as Leave to Construct (S92) application or Environmental Approval.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. If there are needs that do not required regional coordination, Working Group can recommend them to be undertaken as part of the LP approach discussed above. Else, the approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

[4] Also referred to as Needs Screening.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee ("LAC") in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

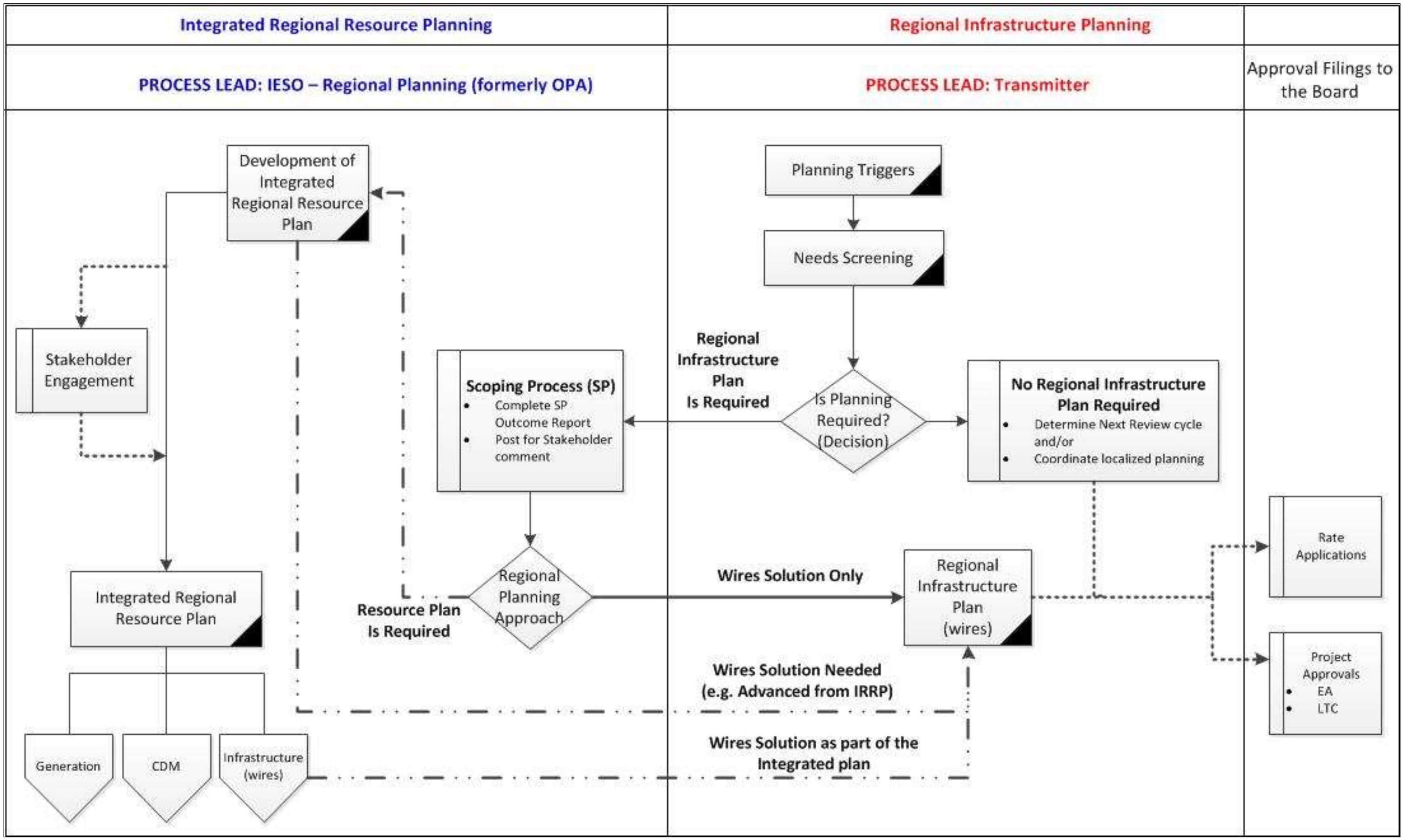

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects the following information and reviews it with the Working Group to reconfirm or update the information as required.

    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation ("DG") or CDM programs;
    - Existing area network and capabilities including any bulk system power flow assumptions;
    - Other data and assumptions as applicable such as asset conditions, load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

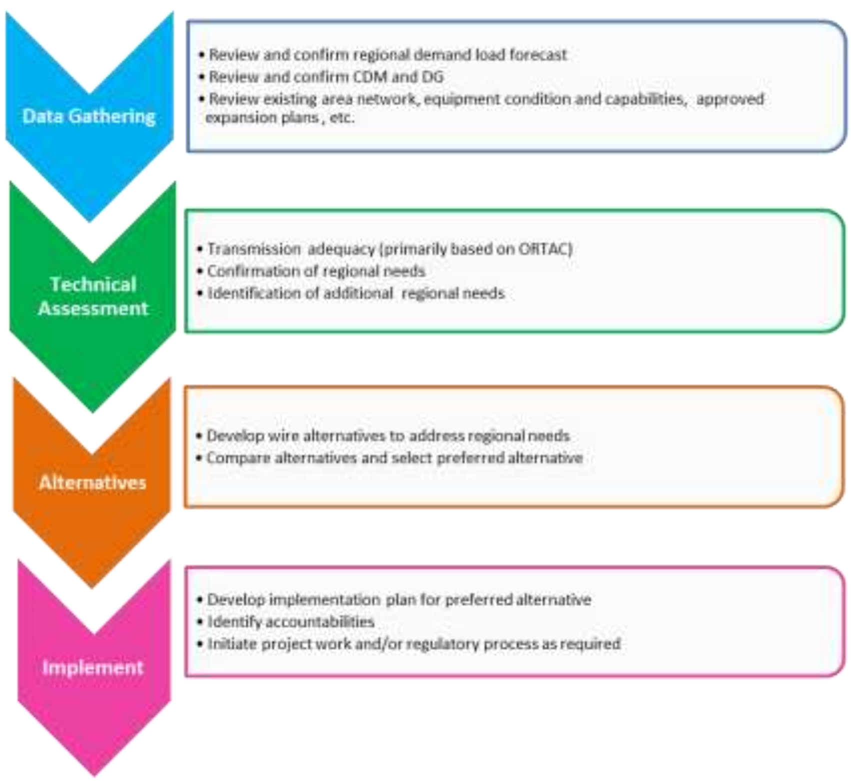

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA EAST REGION IS COMPRISED OF THE PICKERING-AJAX-WHITBY SUB-REGION AND THE OSHAWA-CLARINGTON SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FOUR 230KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 938.5 MW INCLUDING DIRECT TRANSMISSION-CONNECTED CUSTOMERS.

Bulk electrical supply to the GTA East Region is currently provided through Cherrywood TS, a major 500/230kV autotransformer station in the City of Pickering, and five 230kV circuits emanating east from Cherrywood TS that supply four local area step-down transformer stations and four other direct transmission connected load customers. Major generation in the area includes the Pickering Nuclear Generating Station (“NGS”) which consists of six generating units with a combined output of approximately 3000 MW and is connected to the 230kV system at Cherrywood TS.

The August 2014 GTA East Region NA report, prepared by Hydro One, considered the GTA East Region as a whole. Subsequently, the GTA East Region was divided into two sub-regions, Pickering-Ajax-Whitby Sub-Region and Oshawa-Clarington Sub-Region. The IRRP report focused on the needs in the Pickering-Ajax-Whitby Sub-Region. The May 2015 Oshawa-Clarington Sub-Region LP report focused solely on the Oshawa-Clarington Sub-Region. A map of the GTA East Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 Pickering-Ajax-Whitby Sub-Region

The Pickering-Ajax-Whitby Sub-Region comprises primarily the City of Pickering, Town of Ajax, part of the Town of Whitby, and part of the Townships of Uxbridge and Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Cherrywood TS DESN and Whitby TS (2 DESNs), that step down the voltage to 44kV and 27.6kV. The LDCs supplied in the Sub-Region are Hydro One Distribution, Veridian, and Whitby Hydro.

3.2 Oshawa-Clarington Sub-Region

The Oshawa-Clarington Sub-Region comprises primarily the City of Oshawa, part of the Municipality of Clarington, part of Whitby, and part of the Township of Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Wilson TS (2 DESNs) and Thornton TS, that step down the voltage to 44kV, and four other direct transmission connected load customers. Local generation in the area consists of the 60 MW Whitby Customer Generating Station (“CGS”), a gas-fired cogeneration facility that connects to 230kV circuit H26C. Thornton TS also supplies some load within the Pickering-Ajax-Whitby Sub-Region. The LDCs supplied in the Sub-Region are Whitby Hydro, Hydro One Distribution, and OPUCN.

A new 500/230kV autotransformer station in the GTA East Region within the township of Clarington (called Clarington TS) is also being developed and is expected to be in-service in 2018. The new Clarington TS will provide additional load meeting capability in the Region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering NGS. The new autotransformer station will consist of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become the principal supply source for the GTA East Region load.

A single line diagram of the GTA East Region transmission system including the connection of Clarington TS is shown in Figure 3-2.

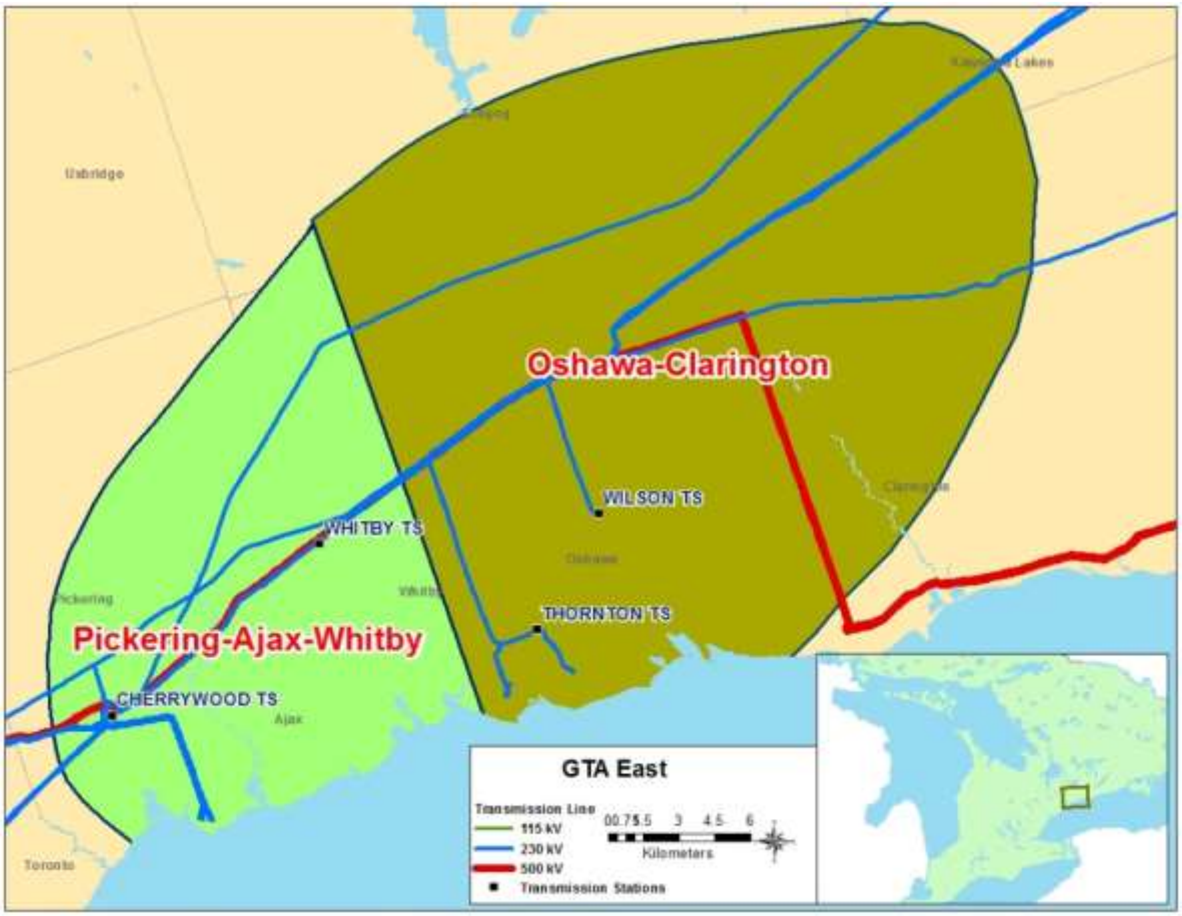

Figure 3-1 GTA East Region – Supply Areas

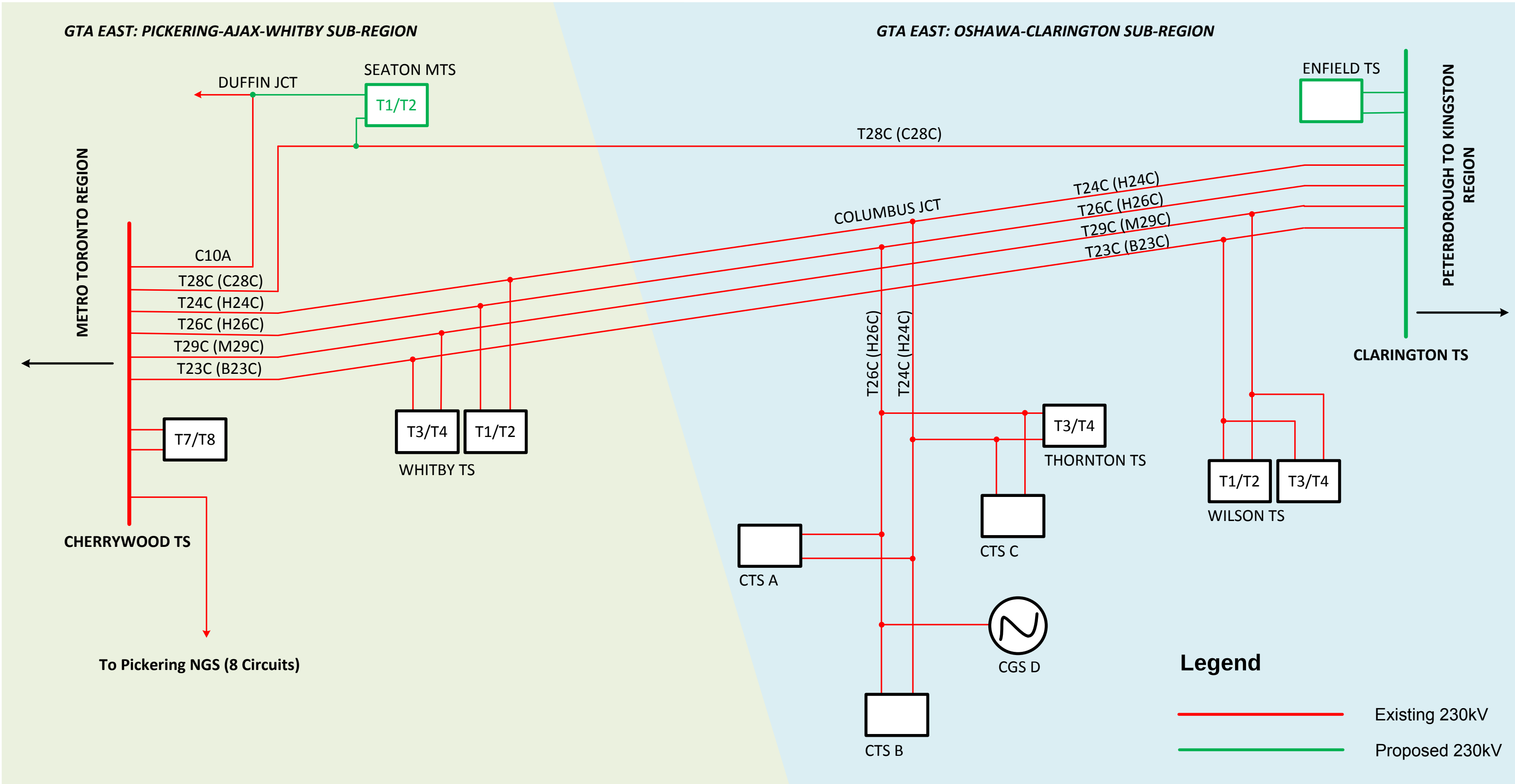

Figure 3-2 GTA East Region Single Line Diagram

Note: Current circuit designations (before Clarington TS is in-service) are provided in brackets

4. TRANSMISSION FACILITIES COMPLETED OR CURRENTLY UNDERWAY OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GTA EAST REGION.

A brief listing of the developed projects along with their in-service dates over the last 10 years is given below:

- Whitby TS T1/T2 (2009) – built new step-down transformer station supplied from 230kV circuits H24C and H26C in municipality of Whitby to increase transformation capacity for Whitby Hydro and Veridian requirements.

- Installed LV neutral grounding reactors at Wilson TS T1/T2 DESN1 (2015) – to reduce line-to-ground short circuit fault levels to facilitate DG connections.

- Thornton TS T3/T4 transformer replacements and install LV neutral grounding reactors (2016) – to replace end-of-life transformers and reduce line-to-ground short circuit fault levels to facilitate DG connections.

The following development projects are currently underway:

- Clarington TS (2018) – a 500/230kV autotransformer station at the Oshawa Area Jct. to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the Region. The thermal limits of the 230kV circuits supplying the Region will be upgraded and will be terminated at Clarington TS.

- Seaton MTS (2019) – a 230/27.6/27.6kV municipal transformer station to increase supply capacity in the Pickering-Ajax-Whitby Sub-Region and provide relief to Whitby TS 27.6kV following the development of new community of Seaton. The station will be serviced by two parallel 230kV circuits, C10A and C28C, emanating from Cherrywood TS. C10A will be extended eastward from Duffin Jct. to the site of the station.

- Enfield TS (2019) – a 230/44kV DESN to increase supply capacity in the Oshawa-Clarington Sub-Region and provide relief to Wilson TS. This station will be located at the Oshawa Area Jct. and will be directly connected to Clarington TS 230kV bus.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA East Region is expected to increase at an annual rate of approximately 2% between 2016 and 2025. The growth rate varies across the Region but an overall coincident growth in the Region is illustrated in Figure 5-1. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix C and D.

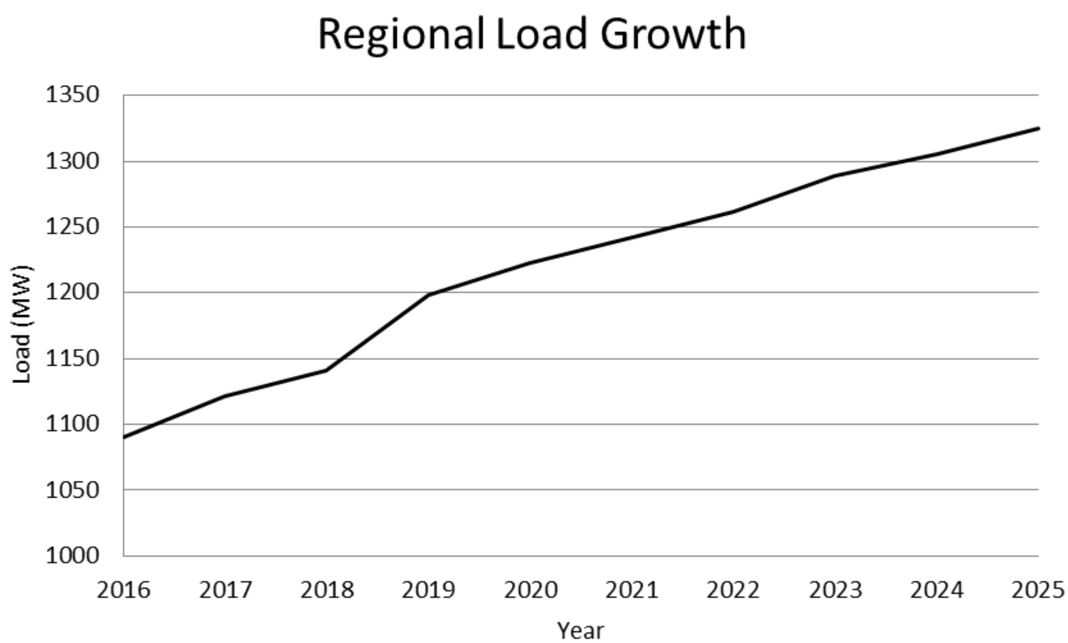

Figure 5-1 GTA East Region Coincident Net Load Forecast

Prior to the RIP's kick-off, the Working Group were asked to confirm load forecast for all stations in the Region provided for previous assessments. The RIP's load forecast for Pickering-Ajax-Whitby Sub-Region did not have a significant revision compared to the IRRP's load forecast. However, the revised forecasted non-coincident stations' peaks for Wilson TS and Thornton TS in the Oshawa-Clarington Sub-Region had a significant increase; therefore, the needs identified in previous assessments were reconfirmed.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2016 – 2025.
- Pickering NGS is assumed to be out-of-service by 2024.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on extreme summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE GTA EAST REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, three regional assessments have been conducted for the GTA East Region. The findings of these studies are input to the RIP:

1. IESO's Pickering-Ajax-Whitby Sub-Region Integrated Regional Resource Plan – June 30, 2016[1]
2. Hydro One's Oshawa-Clarington Sub-Region Local Planning Report – May 15, 2015[2]
3. Hydro One's GTA East Region Needs Assessment Report – August 11, 2014[3]

The IRRP, NA, and LP studies identified a number of regional needs based on the forecast load demand over the near to mid-term. A detailed description and status of plans to meet these needs is given in Section 7.

Based on the regional growth rate referred to in Section 5, this RIP reviewed the loading on transmission lines and stations in the GTA East Region assuming Clarington TS will be in-service by 2018, Seaton MTS and Enfield TS by 2019, and Pickering NGS out-of-service between 2018 and 2024.

Sections 6.1 – 6.3 present the results of this review and Table 6-1 lists the Region's near to mid-term needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Mid-Term Needs in the GTA East Region

Type	Section	Needs	Timing
Step-down Transformation Capacity	7.1	Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	2019
	7.2	Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Immediately
Load Restoration	7.3	Load Restoration for loss of B23C/M29C or H24C/H26C	No action required at this time
Short Circuit Constraint	7.4	Short Circuit Constraint at Cherrywood TS T7/T8	Pending outcome

6.1 500kV and 230kV Transmission Facilities

The GTA East Region is comprised of five 230kV circuits, B23C/M29C, H24C/H26C, and C28C, supplying both the Pickering-Ajax-Whitby Sub-Region and the Oshawa-Clarington Sub-Region. Refer to Figure 3-2 for existing and proposed facilities to be operational in the Region in near future.

Bulk system planning is conducted by the IESO and is informed by government policy such as the long term energy plan ("LTEP"). The next LTEP is expected to be issued in 2017. Any outcomes from this level of planning that impact regional planning are expected to be integrated into the respective regions as necessary.

6.2 Pickering-Ajax-Whitby Sub-Region's Step-Down Transformer Station Facilities

There are two step-down transformer stations in the Pickering-Ajax-Whitby Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in Pickering-Ajax-Whitby Sub-Region

Station	DESN	Voltage Transformation
Cherrywood TS	T7/T8	230/44kV
Whitby TS	T1/T2	230/44/27.6kV
	T3/T4	230/44kV

Based on the LTR of these load stations, additional 27.6kV capacity is required at Whitby TS T1/T2 in 2019 which will be addressed by the proposed Seaton MTS (see details in Section 7.1). Cherrywood TS T7/T8 may be slightly overloaded initially, however, due to CDM and commissioning of Seaton MTS, the capacity need is expected to be eliminated by 2019. Forecast loads at Whitby TS T1/T2 44kV windings, and Whitby TS T3/T4 44kV windings are adequate over the study period.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-3.

Table 6-3 Transformation Capacities in the Pickering-Ajax-Whitby Sub-Region

Station	LTR (MW)	2015 Summer Peak (MW)	Relief Required By
Cherrywood TS T7/T8 44kV	175	156	-
Whitby TS T1/T2 27.6kV	90	41	2019
Whitby TS T1/T2 44kV	90	56	-
Whitby TS T3/T4 44kV	187	161	-

6.3 Oshawa-Clarington Sub-Region's Step-Down Transformer Station Facilities

There are two step-down transformer stations and four direct-connected customers in the Oshawa-Clarington Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in Oshawa-Clarington Sub-Region

Station	DESN	Voltage Transformation
Wilson TS	T1/T2	230/44kV
	T3/T4	230/44kV
Thornton TS	T3/T4	230/44kV
Industrial Customer TS x4	-	-

Based on the LTR of these load stations, additional 44kV capacity is immediately required to provide relief to Wilson TS. Under certain conditions, overloading at Wilson TS T3/T4 was significant enough to plan for emergency rotating load shedding, if and when required. Plan to address this need is discussed further in Section 7.2. Thornton TS is adequate to meet the net demand over the study period.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-5.

Table 6-5 Transformation Capacities in the Oshawa-Clarington Sub-Region

Station	LTR (MW)	2015 Summer Peak (MW)	Relief Required By
Wilson TS T1/T2 44kV	161	167	Immediately
Wilson TS T3/T4 44kV	133	146	Immediately
Thornton TS T3/T4 44kV	159	126	-

The non-coincident and coincident load forecast for all stations in the Region is given in Appendix C and Appendix D, respectively.

7. REGIONAL PLANS

This section discusses the needs, wires alternatives and the current preferred wires solution for addressing the electrical supply needs in the GTA East Region. These needs are listed in Table 6-1 and include needs previously identified in the IRRP for the Pickering-Ajax-Whitby Sub-Region and the NA and LP for the Oshawa-Clarington Sub-Region. Needs for which work is already underway are also included.

The near-term needs include needs that arise over the first five years of the study period (2016 to 2020) and the mid-term needs cover the second half of the study period (2021-2025).

7.1 Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-Region

Description

The Pickering-Ajax-Whitby Sub-Region is supplied by Cherrywood TS at 44kV level and Whitby TS at 27.6kV and 44kV levels. Over the next 10 years, the load in this Sub-Region is forecasted to increase at approximately 2.1% annually.

Based on the DG and CDM forecasts in the Sub-Region, adequate 44kV transformation capacity is available at Cherrywood TS T7/T8 and Whitby TS to maintain reliable supply to meet the demand over the study period.

With the proceeding of a new residential and mixed use commercial area in the Sub-Region, called Seaton, significant increase in load demand is expected at 27.6kV level resulting in a shortage transformation capacity by 2019. The gross demand in the new development of Seaton is expected to be 88MW at the end of the study period (2025) and will continue to grow over long term period. The growth resulting from Seaton will have a significant impact on the 27.6kV transformation capacity in the Sub-Region.

Recommended Plan and Current Status

During the regional planning process, the Working Group considered multiple alternatives to address the transformation capacity in the Sub-Region. Preference was given to already existing facilities to ensure system's maximum capacity had been considered in line with the future demand. Other alternatives included CDM, local generation, and transmission & distribution facilities.

After considering estimated DG and CDM targets over the study period, the stations' capacities in the Sub-Region can be relieved to a certain extent. However, existing facilities alone will not be adequate to meet the future demand resulting from the new Seaton community load planned to be supplied at 27.6kV level.

As a result, an investment in wires infrastructure development in the Sub-Region is mandatory to connect and supply the development of Seaton via transmission/distribution facilities. Following the completion of the IRRP, the Working Group recommended Seaton MTS as the best solution to meet the transformation capacity need in the Sub-Region. Veridian Connections Inc. and Hydro One Networks Inc. have jointly submitted an EA application for the proposed station site and related 230kV transmission line work. Consistent with the regional planning studies, Veridian Connections Inc. is developing a plan for a new transformation station called Seaton MTS in northern Pickering. As confirmed by Veridian, the in-service timeline of this transformation station has been deferred to 2019 due to revised 2018 load forecast.

Class Environmental Assessment (EA) is in progress for the three potential construction sites for Seaton MTS illustrated in Figure 7-1.

Figure 7-1 Seaton MTS: Proposed Construction Sites

The project will have the following connection arrangement:

- From Duffin Jct, extend the circuit C10A east to proposed location under EA process
- Connect 2x75/125MVA, 230/27.6/27.6kV transformers to 230kV circuits; C10A and T28C[5]
- Supply 12x27.6kV feeders with a normally open tie-breaker configuration

The total cost of this project is estimated to be $43M – $48M. This estimate includes the cost of transmission as well as distribution investments which include the station's construction, its connection

[5] T28C circuit nomenclature to replace C28C following Clarington TS (2018)

arrangements as defined above, feeder egress to the distribution risers outside of the station, and a spare transformer.

7.2 Increase Transformation capacity in Oshawa-Clarington Sub-Region

Description

The load forecast reflects an annual growth of 1.85% in Oshawa and Clarington area throughout the study period. Based on the 2015 historical demand and station's net demand forecast, Wilson TS T1/T2 and T3/T4 have already exceeded their respective normal supply capacities and will continue to do so over the study period. Overloading at Wilson TS T3/T4 has been significant enough that plans were put in place for emergency rotating load shedding, if and when required. Thornton TS may briefly exceed its transformation capacity in 2018 and 2019 but is adequate over the study period as well as long term period due to CDM contributions and distribution load transfer capability.

Therefore, based on the current load forecasts, additional transformation capacity relief is required for Wilson TS to accommodate the load growth and improve reliability in this sub-region.

Recommended Plan and Current Status

To accommodate the load growth of Hydro One Distribution's and OPUCN's feeders at Wilson TS, a new transformer station, Enfield TS, is recommended to relief the transformation capacity. The proposed transformer options to be evaluated for the DESN are as follows:

1. 2x75/125MVA, 230/44kV transformers with 6x44kV feeder breaker positions, with space for future 2x44kV feeder positions and capacitor banks (Preliminary Cost Estimate: $23 million)
2. 2x75/125MVA, 230/44kV transformers with 8x44kV feeder breaker positions (Preliminary Cost Estimate: $27 million)

The Working Group recommends option 1 to address the transformation capacity need in the Sub-Region. Six feeders will be adequate to supply demand over the study period. Also, option 2 is not considered the best economic solution since option 1 will reserve extra space for 2x44kV feeder positions and capacitor banks for future, when required.

The new DESN, 2x75/125MVA 230/44kV transformers with 6x44kV feeder breaker positions with 2x44kV spare feeder positions, is proposed to be located at the Oshawa Area Junction in the municipality of Clarington. This junction is on the ROW of the Bowmanville and Cherrywood transmission line corridor illustrated in Figure 7-2. The property is already owned by HONI and it is also the site of the new 500/230kV autotransformer Clarington TS supplied by circuits B540C and B543C. The proposed in-service date for the new DESN has a preliminary cost estimate of $34M including feeders egress to the distribution risers outside the station and will be aligned with Clarington TS which is scheduled for 2018.

Figure 7-2 Enfield TS: Proposed Construction Site

Advantages in proceeding with this particular location are as follows:

- The land proposed has already been purchased as part of the property where Clarington TS will be situated resulting in one less station footprint in the Sub-Region.
- Class EA approval has been already obtained for the construction of new TS on Hydro One land at the Clarington TS site.
- The site is also near new development areas which results in minimizing the length of supply feeders from the station.

7.3 GTA East Load Restoration Assessment

Description

GTA East load restoration need was identified in the NA and IRRP reports as the Working Group recommended that further assessment was required to address the supply shortfall during peak load periods. Previous assessments indicated that for the loss of two transmission elements (B23C/M29C or H24C/H26C), the load interrupted with current circuit configuration during peak periods may exceed load restoration criteria and requires further assessment.

Recommended Plan and Current Status

In collaboration with the Working Group, a detailed report[6] was completed to make a recommendation for the load restoration need identified in the Region. The Working Group's assessments in the report, attached in the Appendix F, concluded the following:

- The historical performance of the circuits over the last 15 years has been excellent with little or no impact on supply reliability and security.

- Working Group is recommending that further investment in motorized disconnect switch (MDS) at this time is not a feasible solution to the load restoration need because the risk and/or probability of loss of load is small based on past performances. Therefore, no further action is required at this time.

7.4 Short Circuit Constraint at Cherrywood TS T7/T8

Description

Currently, new DG is restricted from connecting to Cherrywood TS T7/T8 due to short circuit capacity constraints. Veridian Connections Inc., supplied by this station, has indicated that they have several customers that have expressed interest in connecting DG (over 5MW) to Cherrywood TS T7/T8 but are prevented due to the existing restriction. There is an existing 30MW landfill gas generation connection at Cherrywood TS T7/T8 contributing to the short circuit capacity restriction. This generating unit has been shut down and/or has not generated electricity now for more than one year.

Recommended Plan and Current Status

The short circuit capacity is currently held by an earlier landfill generation connection. Although the facility has not been generating and partially dismantled, there is an uncertainty about availability of the short circuit capacity. Hydro One and the IESO will continue to assess this issue to have this capacity reservation released.

[6] GTA East: Load Restoration, Transmission Planning Report, circulated within the Working Group on August 31, 2016

7.5 Long Term Regional Plan

As discussed in Section 5, the electricity demand in GTA East Region is forecasted to grow at 2% annually over the next 10 years. Similar trend is also expected in the long term period where the load is expected to increase by approximately 1.3% annually from year 2026 to 2036. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

No long term needs for the Pickering-Ajax-Whitby Sub-Region were identified in the IRRP. Seaton MTS is expected to supply the Sub-Region's demand adequately over the next two decades. As indicated in the IRRP, official plans by the municipalities expect the lakeshore area in the southern part of Pickering-Ajax-Whitby Sub-Region to grow due to development of high rise residential and commercial buildings. With Pickering NGS expected to retire by 2024, the 230kV transmission lines can be utilized along with a new step-down transformer station to address capacity needs in the southern part of the Sub-Region.

The current forecast did not consider future Pickering Airport which may have an impact on transformation capacity in the long term. Such potential needs will be monitored and system supply capability will be reviewed in the next planning cycle based on the official plans released by the municipalities.

The demand in Oshawa-Clarington Sub-Region is expected to grow over the long term period. The new Enfield TS will mainly provide relief to Wilson TS by supplying the excess load through distribution load transfer capability. As the demand grows in the northern Oshawa area in the long term, additional transformation capacity may have to be planned for in future. Further review and assessment will commence in next Regional Planning cycle to identify and develop alternatives to address new needs.

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA EAST REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in Table 8-1.

Table 8-1: Regional Plans – Needs Identified in the Regional Planning Process

Need ID	Needs	Timing
I	Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	2019
II	Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Immediately
III	Load Restoration for loss of B23C/M29C or H24C/H26C	No action required at this time
IV	Short Circuit Constraint at Cherrywood TS T7/T8	Pending outcome
V	Additional transformation capacity for Oshawa-Clarington Sub-Region	Long term

Projects, lead responsibility, and timeframes for implementing the wires solutions for the above needs are summarized in Table 8-2 below.

Table 8-2: Regional Plans – Projects, Lead Responsibility, and Planned In-Service Dates

#	Project	Lead Responsibility	I/S Date	Estimated Cost	Mitigated Need ID
1	Seaton MTS and associated line work	Veridian and Hydro One	2019	$43M-$48M	I
2	Enfield TS	OPUCN and Hydro One	2019	$34M	II

GTA East load restoration need, Need ID III, has been reviewed in this Regional Planning cycle and "status quo/do nothing" course of action has been recommended (see Appendix F). Further developments in the Region will be monitored and the need will be reviewed again as part of the next planning cycle.

Hydro One is working with the IESO to explore the best course of action to relieve the short circuit constraint at Cherrywood TS, Need ID IV.

Additional transformation capacity for Oshawa-Clarington Sub-Region, Need ID V, will be reviewed as part of the next Regional Planning cycle.

In accordance with the Regional Planning process, the Regional Planning cycle will be triggered at least once within five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1]. Independent Electricity System Operator, "Pickering-Ajax-Whitby Sub-Region Integrated Regional Resource Plan". June 30, 2016.
http://www.ieso.ca/Documents/Regional-Planning/GTA_East/2016-Pickering-Ajax-Whitby-IRRP-Report.pdf

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http://www.hydroone.com/RegionalPlanning/GTA_East/Documents/Local%20Planning%20Report%20-%20WilsonThornton%20-%2015_May_2015%20-%20Final.pdf

[3]. Hydro One, "Needs Screening Report, GTA East Region. August 11, 2014.
http://www.hydroone.com/RegionalPlanning/GTA_East/Documents/Needs%20Assessment%20Report%20-%20GTA%20East%20Region.pdf

[4]. "Planning Process Working Group (PPWG) Report to the Board The Process for Regional Infrastructure Planning in Ontario". May 17, 2013.
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

[5]. Independent Electricity System Operator, "Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0"
http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

APPENDICES

Appendix A: Stations in the GTA East Region

Station (DESN)	Voltage Level	Supply Circuits
Cherrywood TS T7/T8	230/44kV	Cherrywood TS, Bus DK
Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	H24C/H26C
Whitby TS T3/T4	230/44kV	B23C/M29C
Wilson TS T1/T2	230/44kV	B23C/M29C
Wilson TS T3/T4	230/44kV	B23C/M29C
Thornton TS T3/T4	230/44kV	H24C/H26C

Appendix B: Transmission Lines in the GTA East Region

Location	Circuit Designation	Voltage Level
Cherrywood TS to Whitby TS T3/T4, Wilson TS, and Clarington TS	B23C/M29C	230kV
Cherrywood TS to Whitby TS T1/T2, Thornton TS, and Clarington TS	H24C/H26C	230kV
Cherrywood TS to Clarington TS	C28C	230kV

Appendix C: Non-Coincident Load Forecast 2016-2025

Transformer Station Name	LDC/Customer	DESN ID	Bus ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cherrywood TS	Veridian	*T7/T8*	*BY (44kV)*	*175*	Gross Peak Load				180	180	180	180	180	180	180	180	176	176
					CDM				2	3	5	7	8	10	11	12	13	15
					Net Load Forecast	163	143	156	178	177	175	173	172	170	169	168	163	161
Whitby TS	Veridian	*T1/T2*	*BY (27.6kV)*	*90*	Gross Peak Load				61	76	80	90	90	90	90	90	90	90
	Whitby Hydro		*EZ (44kV)*	*90*	Gross Peak Load				54	55	56	57	57	58	59	60	61	62
					DG				0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
					CDM				2	3	4	6	7	8	9	10	12	13
					Net Load Forecast	77	88	97	113	128	132	141	141	140	140	140	139	139
Whitby TS	Veridian	*T3/T4*	*JQ (44kV)*	*187*	Gross Peak Load				70	70	74	74	74	74	74	74	74	74
	Whitby Hydro				Gross Peak Load				108	110	111	113	115	116	118	120	122	124
					DG				18	18	18	18	18	18	18	18	18	18
					CDM				2	3	5	6	8	9	11	13	15	17
					Net Load Forecast	175	161	162	159	160	163	164	163	164	164	164	163	163
Seaton MTS	Veridian	*T1/T2*	*(27.6kV)*	*153*	Gross Peak Load							5	16	27	40	60	75	88
					CDM								1	1	2	3	4	6
					Net Load Forecast	0	0	0	0	0	0	5	15	26	38	57	71	82
Wilson TS	OPUC	*T1/T2*	*BY (44kV)*	*161*	Gross Peak Load				156	161	167	148	145	142	140	140	140	140
	Hydro One				Gross Peak Load				30	31	35	35	41	41	41	41	41	41
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.80%	7.20%
					Net Load Forecast	157	174	167	184	189	197	176	177	173	170	170	169	168
Wilson TS	OPUC	*T3/T4*	*JQ (44kV)*	*134*	Gross Peak Load				25	26	27	25	25	25	25	25	25	25
	Hydro One				Gross Peak Load				150	151	152	152	153	154	155	156	157	158
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.80%	7.20%
					Net Load Forecast	166	133	146	173	174	174	171	170	170	170	170	170	170

Transformer Station Name	LDC/Customer	DESN ID	Bus ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Thornton TS	Whitby Hydro	*T3/T4*	*BY (44kV)*	*160*	Gross Peak Load				52	58	63	79	80.0	81	82	82	83	84
	OPUC				Gross Peak Load				100	101	103	95	88	86	84	80	80	80
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.8%	7.2%
					Net Load Forecast	157	103	126	151	156	162	168	160	158	156	152	152	152
Enfield TS	OPUC	T1/T2	*(44kV)*	*153*	Gross Peak Load				0.0	0.0	0.0	38	57	71	84	98	108	118
	Hydro One				Gross Peak Load				0.0	0.0	0.0	26	33	34	35	36	37	38
					CDM							3.9%	4.7%	5.3%	5.9%	6.3%	6.8%	7.2%
					Net Load Forecast				0	0	0	62	86	100	113	126	135	145
CTS A					Gross Peak Load				20.0	20.0	20.2	20.6	21.0	21.2	21.4	21.6	21.7	21.9
					Net Load Forecast			19.5	19.8	19.7	19.8	19.9	19.9	20.0	20.1	20.2	20.2	20.3
CTS B					Gross Peak Load				97.0	97.5	98.0	99.8	101.6	102.2	103.0	103.4	103.9	104.4
					Net Load Forecast			96.3	96.0	96.1	96.2	96.3	96.3	96.4	96.5	96.6	96.6	96.7
CTS C					Gross Peak Load				47.5	52.8	53.3	54.5	55.7	56.3	57.0	57.5	58.0	58.5
					Net Load Forecast			52	47.0	52.0	52.3	52.6	52.8	53.1	53.4	53.7	53.9	54.2
CGS D					Gross Peak Load				0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
					Net Load Forecast			0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

Appendix D: Coincident Load Forecast 2016-2025

Stations	DESN ID	Historical (MW)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cherrywood TS	T7/T8	156	173	172	170	168	167	165	164	163	158	156
Whitby TS (27.6kV)*	T1/T2	33	59	74	78	87	87	87	87	87	87	87
Whitby TS (44kV)*	T1/T2	39	52	53	54	55	56	56	57	58	59	60
Whitby TS	T3/T4	145	154	155	158	159	158	159	159	159	158	158
Seaton MTS	T1/T2	0	0	0	0	5	15	25	37	55	69	80
Wilson TS	T1/T2	128	179	184	192	172	173	169	166	166	165	164
Wilson TS	T3/T4	144	168	169	169	166	165	165	165	165	165	165
Thornton TS	T3/T4	125	146	151	157	163	155	153	151	147	147	147
Enfield TS	T1/T2	0	0	0	0	60	83	97	110	122	131	141
CTS A		19.5	19	19	19	19	19	19	19	20	20	20
CTS B		96.3	93	93	93	93	93	93	94	94	94	94
CTS C		52	46	50	51	51	51	51	52	52	52	53
CGS D		0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

*DG/CDM contribution excluded from 2016-2036 coincident forecast

GTA East Coincident Load	938.5	1091	1122	1141	1199	1223	1242	1262	1289	1306	1324
Region’s Annual Growth Rate		2%									

Appendix E: List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Appendix F: GTA East Load Restoration Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

TRANSMISSION PLANNING REPORT

GTA East: Load Restoration

Revision: Final
Date: August 31, 2016

Prepared by: Hydro One Networks Inc.

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Executive Summary

REGION	GTA East (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	June 17, 2016	**END DATE**	August 31, 2016

1. INTRODUCTION

The purpose of this Transmission Planning (TP) report is to undertake a comprehensive assessment of the load restoration need identified in the Needs Assessment (NA) and Integrated Regional Resource Plan (IRRP) and develop a preferred recommendation. The recommendations of this TP report will become part of the Regional Infrastructure Plan (RIP) and is intended to facilitate the regional planning process as set out by Ontario Energy Board's (OEB) in the Transmission System Code (TSC) and the Planning Process Working Group (PPWG) report to the Board.

Based on Section 6 of the NA and IRRP report, the study team recommended that further assessment was required to address the load restoration need during peak load in the GTA East region. The NA and IRRP report indicated that for the loss of two transmission elements (B23C/M29C or H24C/H26C), the load interrupted with current circuit configuration may exceed load restoration criteria and requires further assessment. The IESO led IRRP recommended this need be further assessed in the RIP, to be completed in Q4 2016. This report provides a detailed assessment along with options and the WG recommendation to be included in the RIP report.

2. REGIONAL NEED ADDRESSED IN THIS REPORT

The circuits M29C/B23C and H24C/H26C are on the same tower line in the GTA East Region 230kV corridor. The loss of either pair of circuits during peak load may result in load shortfall/outage exceeding the limits of 150MW and 250MW to be restored within 4 hours and 30 minutes, respectively.

3. OPTIONS CONSIDERED

Hydro One Transmission along with the WG members have considered the following options to addressing the load restoration need:

Option 1 – a) Status quo/Current state
b) Commissioning of Clarington TS by 2018

Option 2 – Install 8 Motorized Disconnect Switches (MDS) on circuits B23C, M29C, H24C, and H26C

See Sections 4 & 5 for detailed assessment.

4. PREFERRED SOLUTION

At this time, B23C, M29C, H24C, and H26C are approximately 120km-300km long and the historical performance since 2000 has been excellent with no relevant outages. With the new Clarington TS in 2018, the line exposure in the region will reduce to only 46km including tap sections. The assessment concluded that

a) The annual carrying cost of the switches is not justified compared to the annual outage cost, and
b) The installation of Motorized Disconnect Switches will not result in significant enhancement to the reliability of the system after the Clarington TS is in service in 2018.

Option 1 is the preferred solution recommended by the WG at this time. Further details of the assessment and justification are provided in Sections 4 & 5.

5. NEXT STEPS

There are no further actions required at this time.

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1 Region Description and Connection Configuration

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham Region.

Four 230kV circuits (B23C, M29C, H24C, and H26C) emanating east from Cherrywood TS provide local supply to the Region. Whitby TS DESN2, Thornton TS, and other CTS in the Region are supplied by H24C/H26C while Whitby TS DESN1 and Wilson TS are supplied by B23C/M29C.

A new 500/230kV autotransformer station in the GTA East Region within the municipality of Clarington (called Clarington TS) is expected to be in service by 2018. The assessments in this report evaluate the reliability impact of Clarington TS in the region as well as the installation of Motorized Disconnect Switches (MDS). The new Clarington TS will provide additional load meeting capability in the Region and will eliminate any overloading of Cherrywood autotransformers that may result after the retirement of the Pickering Nuclear Generating Station (NGS). The new autotransformer station will consist of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become the principle supply source for the GTA East Region load. The facilities in the GTA East Region, including the connection to Clarington TS, are depicted in the single line diagram shown in Figure 1[1].

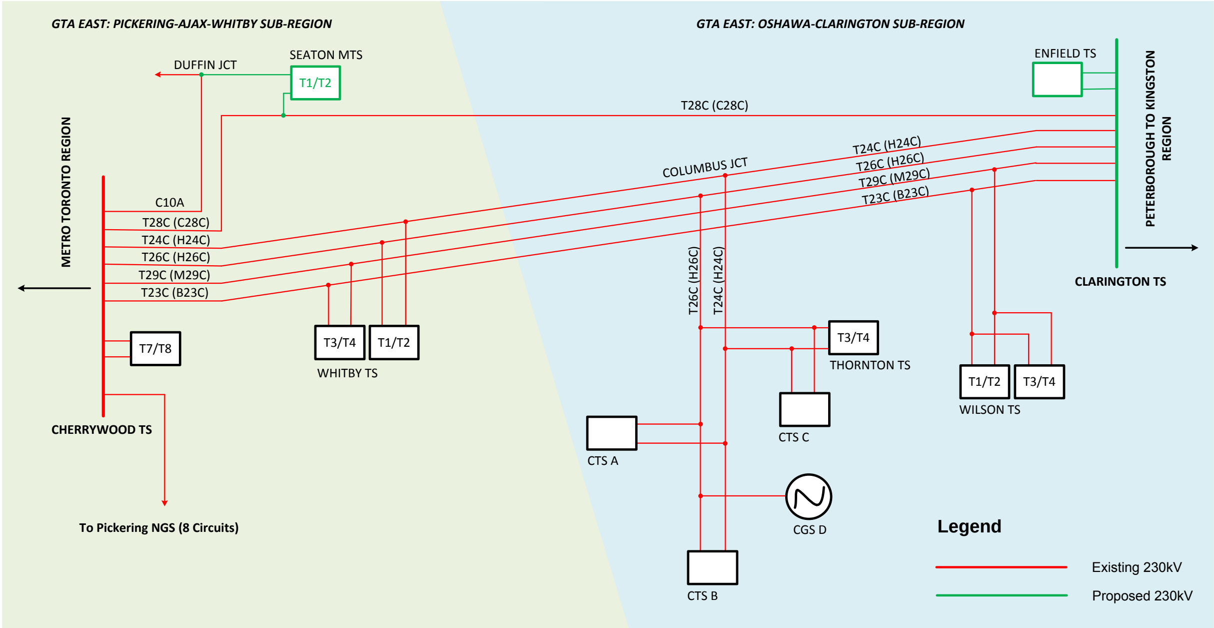

Figure 1 **GTA East Region - Single Line Diagram**

[1] Circuits' nomenclature is shown following the commissioning of Clarington TS (2018) with current convention in parentheses

2 Identified Need

2.1 Load Restoration Criteria

In case of contingencies on the transmission system, the Ontario Resource Transmission Assessment Criteria (ORTAC) provides the load restoration times relative to the amount of load affected. Planned system configuration must not exceed 600MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

a. All loads must be restored within approximately 8 hours.
b. Load interrupted in excess of 150MW must be restored within approximately 4 hours.
c. Load interrupted in excess of 250MW must be restored within approximately 30 minutes.

In addition, ORTAC also provides a provision for exemption from the above restoration criteria on a case-by-case basis.

Figure 2 illustrates the load restoration timelines as discussed above.

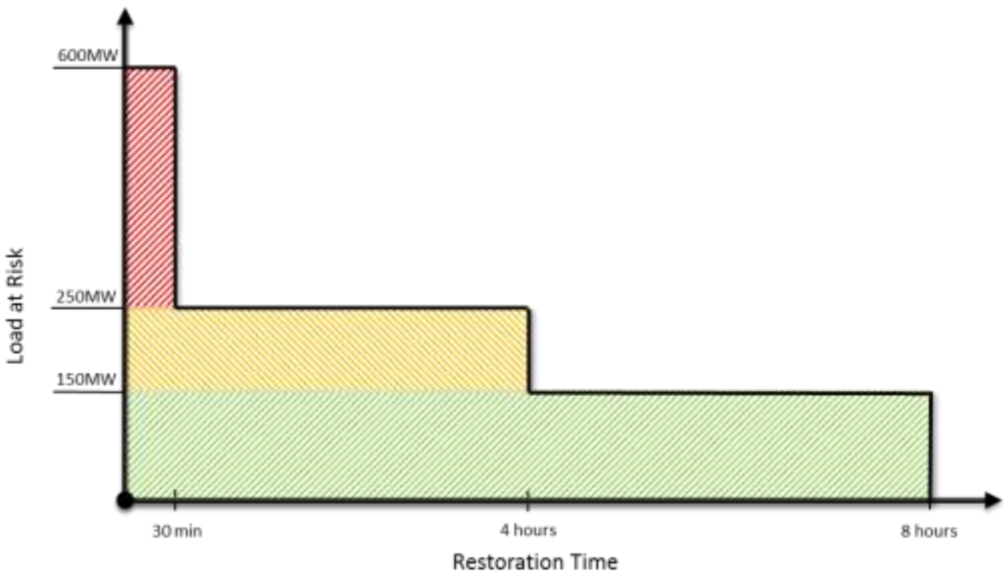

Figure 2 **Load Restoration Criteria**

2.2 Shortfall Need

In 2015, H24C/H26C and M29C/B23C supplied a coincident peak demand of approximately 366MW and 417MW, respectively.

It is expected and assumed that all loads can be restored within 8 hours. However, consistent with the NA and IRRP reports, during peak load periods all loads cannot be restored in the region subsequent of a double circuit contingency between Cherrywood TS and Clarington TS within 30 minutes to 4 hours.

Further findings from the Local Distribution Companies (LDC) in the Region and as reported in the IRRP[2], up to 57MW and 142MW can be restored for customers supplied by H24C/H26C through distribution transfers within 30 minutes and 4 hours, respectively. This leaves the maximum shortfall of 59MW after 30 minutes, and 74MW after 4 hours to be restored from these circuits.

Similarly, for the M29C/B23C, up to 105MW can be restored through distribution transfers within 30 minutes and 257MW within 4 hours for customers supplied by these circuits under the current supply arrangement. This leaves the maximum shortfall of 62MW after 30 minutes, and 10MW after 4 hours to be restored from these circuits.

Table 1 summarizes the 2015 peak demands for each pair of circuit and differentiates between restorable load and the shortage load for 30-minutes and 4-hour periods as discussed above.

Table 1 **Load Restoration/Shortfall in 2015**

2015 Coincident Peak					
Load Pocket	**Actual Demand**	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24C/H26C: Whitby TS DESN 1, Thornton TS, and Transmission Connected Customers	366	57	59	142	74
M29C/B23C: Whitby TS DESN2, Wilson TS	417	105	62	257	10

By the end of 2025, the load that cannot be restored increases due to load growth in the region illustrated in Table 2.

Table 2 **Load Restoration/Shortfall in 2025[3]**

2025 Coincident Peak (Net Forecast)					
Load Pocket	**Forecast Demand**	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24C/H26C: Whitby TS DESN 1, Thornton TS, and Transmission Connected Customers	445	57	138	142	153
M29C/B23C: Whitby TS DESN2, Wilson TS	425	105	70	257	18

[2] Published in June, 2016
[3] Load forecast is subject to change

2.3 Options considered

An option to build a new 26km of line would have resulted in a cost of more than $75M, obtaining new right-of-way and was not further considered. Following options were further assessed:

Option 1a is status quo and option 1b includes Clarington TS to be in-service by 2018. Accordingly, following two options are further evaluated against each other:

Option 1 – a) Status quo/current state
b) Commissioning of Clarington TS by 2018

Option 2 – Install 8 Motorized Disconnect Switches (MDS) on circuits B23C, M29C, H24C, and H26C

A conceptual configuration of the switches (marked by the red X) is shown for Option 2 in Figure 3.

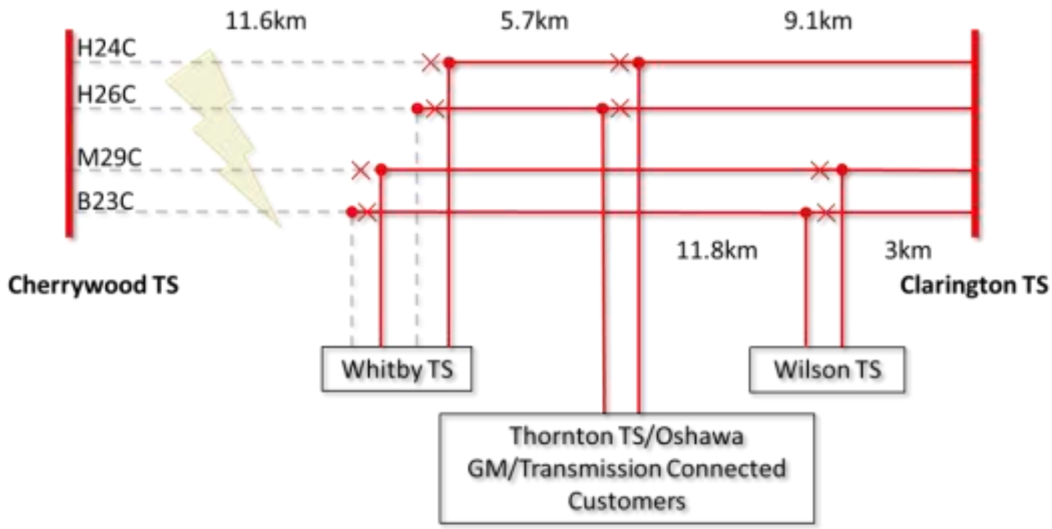

Figure 3 **MDS: Conceptual Configuration**

Similar cases can be shown to isolate faults on other sections of the corridor to restore the loads. It must be noted that although the corridor is protected using 8 MDSs as shown above, the tap offs will still remain unprotected. Further, a common mode fault (refer to section 4) at the tap off line sections will cause an outage regardless of installed switches. With the use of 8 MDS, the optimal locations of the switches are the junction points and 2 switches per circuit as shown in Figure 3.

3 Evaluation Method & Assumptions

The options identified in the previous section were evaluated from the reliability and cost points of view. The reliability indices for overlap outages were evaluated with the help of the AREP Program (Area Reliability Evaluation Program). The reliability for each option is expressed in terms of the frequency and duration of supply interruptions to customers.

Two cost components, one representing the capital cost and one representing the outage cost were evaluated for each option. The two annual costs are given as follows:

Annual cost of carrying charge = C*R,

Where: C – Capital cost of the switches
R – Annual discount rate

The annual outage cost (or risk cost) = F*P*I,

Where: F – Annual duration of load interruption in hours
P – Average kW interrupted including load factor
I – Customer interruption cost ($/KWh)

The following assumptions were made in the assessments:

1. All MDSs are assumed to be perfect (100% reliable).
2. Outages on line tap sections are excluded in common mode outages assessment in section 4.
3. All customer loads are restored within 8 hours for Option 1 and within 30 minutes for Option 2.
4. In case of overlap outages, switching time to isolate the faulted component and restore healthy ones to service is assumed to be one hour.
5. Faults do not occur on lines section where MDSs are located.

The assessment data used in the benefit/cost analysis for all options is provided in Table 3.

Table 3 **Data Used in Reliability Studies**

Assessment Data	
No. of circuit pairs on same towers	27
Total circuit length	551.347km
Circuit years in service	26 years
Distance between Cherrywood TS and Clarington TS	26km
2015 Peak load supplied from B23C and M29C, P	417MW
2015 Peak load supplied from H24C and H26C, P	366MW
Load factor for all load stations	0.6
Customer interruption cost, I	\$10–\$30/kWh[4]
Load restoration time without switches	8 hours
Load restoration time with switches	30 minutes
Cost of one switch (x4 per pair, C)	\$3 Million (\$12 Million)
Annual discount rate, R	5%

[4] Known as Value of Lost Load (VOLL), range is consistent with a Canadian Regulatory Application conducted in 2006 after considering customer composition and provincial GDP – IRRP (2016)

4 Impact of Common Mode Outages

A common mode outage is defined as an event involving two or more outages with the same initiating cause and where the outages are not consequences of each other and occur nearly simultaneously.

4.1 Line Outage Data

The historical common mode outage data for all 230 kV circuits on same structures and east of Cherrywood TS from 1990 to 2015 was used to compute the frequency and duration of common mode line outages. A summary of the common mode line outage events, along with the duration, over the period of 25 years is given in Table 4.

Table 4 **Common Mode Outage Events (from 1990 to 2015)**

Event #	Circuits Involved	Year	Outage Duration	Outage Cause
1	X3H and X4H	1992	927.6h	High winds toppled 16 towers
2	D5A and B5D	1998	0.15h or 9m	Electrical storm
3	B23C and M29C	2008	2.02h	Human error, relay settings
4	L21H and L22H	2011	0.08h or 5m	Relay problems

Only 4 common mode outages have been recorded in eastern Ontario in the last 25 years, of which, only one event is of relevance for this assessment. Hence, Event # 1, in Table 4 is the only one used in calculating the frequency of common mode line outages. This event occurred in November 1992 where adverse weather toppled multiple towers. The other outage events are not relevant to common mode outages because either the outage duration is less than 30 minutes (time assumed for switches to restore power supply to customers) or the outage was preventable or both.

NOTE: Event #1 has never occurred on the GTA East 230kV corridor which is the scope of this assessment but used as a proxy for assessment.

4.2 Reliability Results

The annual frequency of line common mode outages for 230 kV circuits east of Cherrywood TS was calculated by dividing the number of common mode line outages in 25 years by the product of the number of circuit in service years and the total circuit km over the 25 years period. The annual frequency was found to be **0.00007 outages/km** for all of eastern Ontario's 230kV transmission circuits. A low reliability index indicates the circuits in eastern Ontario have performed exceptionally well.

The commissioning of Clarington TS, Option 1b, does not affect the reliability indices for the common mode line outages because of the location of the station at the Oshawa Area Junction. All four 230 kV circuits currently emanate east on single towers from Cherrywood TS to the Oshawa Area junction point. From there on, B23C disperses south towards Belleville TS while the remaining three circuits emanate east on individual towers towards eastern Ontario. Therefore, a common mode line outage on these circuits cannot occur east of Oshawa Area

Junction, future site for Clarington TS.

It is also emphasized that the MDS would have no impact on the frequency of supply interruptions to customers. However, depending upon the location of a permanent fault, the switches can reduce the duration of interruption to customers by isolating the faulted section of the line and restoring the load from the alternative path.

The frequency and duration indices for all options are given in Table 5. The 8 hour restoration time for Option 1a and 1b, without switches, is in accordance with the standard outlined in ORTAC.

Table 5 **Reliability Indices, Common Mode Line Outages**

Options	Annual Frequency of Loss of Supply to any Customer	Duration of loss of Supply in Hours per Occurrence	Annual Duration of Supply Interruptions, F
Option 1a or 1b	0.00182	8	0.01456h or 52.4s
Option 2	0.00182	0.5	0.00091h or 3.3s

4.3 Cost Results

The capital cost and outage cost components were evaluated for all options using the formulae stated earlier. Table 6 shows the results for Circuits B23C and M29C while Table 7 shows the results for Circuits H24C and H26C.

Table 6 **Cost Results, Common Mode Line Outages (B23C/M29C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a or 1b	$0.00	$36.43-$109.29	$36.43-$109.29
Option 2	$600.00	$2.28-$6.84	$602.28-$606.84

Table 7 **Cost Results, Common Mode Line Outages (H24C/H26C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a or 1b	$0.00	$31.97-$95.92	$31.97-$95.92
Option 2	$600.00	$2.00-$6.00	$602.00-$606.00

The reliability and cost benefit assessment for the common mode line outages is based on the past 25 years of historical performance of 230kV circuits in eastern Ontario. Based on these findings, the annual reliability index for the GTA East region is only 0.00182 outages. As stated earlier, the installation of switches will not have an impact on the frequency index of events. Rather, as seen in Table 5, the duration of an event is the only dependent variable where the annual duration of an outage is reduced from 52.4s to 3.3s with the installation of switches.

The cost analysis in each option is dependent on the reliability index and is calculated using the assessment data provided in Table 3. Using the cost calculation formulas in Section 3, annual carrying cost of the switches and annual outage costs are calculated for B23C/M29C and

H24C/H26C. The annual carrying cost of the 4 switches per circuit pair is based on the minimum operating period of 20 years while the annual outage costs are based on the duration of outages, calculated from the reliability index, with and without the installation of switches.

The annual cost for just common mode line outages for each pair in the region is approximately \$32k-\$109k while the annual carrying cost of switches, including cost of outages, for each pair is nearly 5-19 times more, \$602k-\$607k. Also, the annual outage cost due to a common mode line outage is calculated on a very small probability of an event occurring. The annual frequency of loss of supply to any customer in the region is only 0.00182 outages, 1 in over 549 years, with or without switches as MDS have no impact on the frequency of supply interruptions.

As shown, the annual reliability and cost benefits from the MDS are insignificant compared to the annual carrying costs of the switches. The installation of switches improves the outage duration, if occurred, from 52.4s to 3.3s for a certain annual investment of over \$1.2M for both pairs of circuits. The annual benefits will still be lower than the carrying costs even if higher values are used for the frequency of common mode line outages. In addition, MDS are assumed to be 100% reliable in this assessment while they introduce a weak link on the system. The reliability and cost analysis show that the installation of MDS is not justifiable.

5 Impact of Overlap Outages

An overlap outage is referred to an event where two or more components are out of service at the same time. The outage initiating causes are different and outages can start at different time. The overlap outage may occur as one of two types; Forced-Forced or Planned-Forced.

5.1 Line Outage Data

The historical outage data from 1990 to 2014 was used to compute the frequency and duration of H24C/H26C line sections and line terminal indices due to forced and planned outages. A reliability model was developed using Area Reliability Evaluation Program (AREP) for both options. The reliability indices were then used to calculate the annual frequency and annual duration of loss of supply to customers. It is expected that circuits B23C/M29C will have similar reliability indices, if not better, due to comparable characteristics and load as circuits H24C/H26C.

5.2 Reliability Results

Currently, the four circuits collectively supply eastern Ontario for 120–300km. In spite of this long distance, the reliability and security of the transmission lines in this part of the province has been exceptional based on the historical performances. Given that these 230kV circuits will now be terminating at Clarington TS, the exposure will reduce to 26km, the region's security and reliability is expected to improve substantially. Table 8 illustrates the reliability indices for the loss of supply to customers considering both types of overlap events: Forced-Forced and Planned-Forced.

Table 8 **Reliability Indices, Overlap Line Outages**

Options	Annual Frequency of Loss of Supply	Annual Duration of Supply Interruptions
Option 1a	0.01	0.12h or 7.02m
Option 1b	0.0008	0.007h or 26.60s
Option 2, Whitby TS DESN 1	0.0001	0.0003h or 1.26s
Option 2, Thornton TS/CTSs	0.0004	0.002h or 8.47s

For each reliability index above, two sets of reliability indices were considered: one due to the overlap of forced outages (Forced-Forced) only and one with the overlap of planned and forced outages (Planned-Forced). In the course of the overlap outages' assessment, it was observed that the Planned-Forced type outages had the dominant impact on the final reliability indices when compared to Forced-Forced type outages.

Further, two types of outages in each set, namely the permanent outages and the switching outages, were computed. In the permanent outage, the supply to customers is restored after repairing the failed components while in the switching outage; the supply to customers is restored by switching off the failed components and restoring the healthy ones to service. The switching time to isolate the faulted component and restore healthy ones to service is assumed to be one hour except in the case of Option 2 where MDSs are expected to operate within 30 minutes.

It is observed in Table 8 that with the commissioning of Clarington TS in 2018, the reliability improves by over 92% while an additional investment in MDSs of over $24 million yields another increment of only 7% to the system reliability. With Clarington TS in service, Option 1b, the reliability indices improve significantly when compared to the reliability of the existing supply system. Also, the annual duration of supply interruption is reduced to just 26.6 seconds from 7 minutes with Clarington TS in the region.

5.3 Cost Results

The capital (carrying) cost and outage cost components were evaluated for the both options using the formulae stated earlier and the results are shown in Table 9. These costs are mainly dependent on the annual duration of supply interruption in Table 8. Since the annual duration of supply interruption in the region is expected to be reduced to merely 26.6s with Clarington TS soon to be in service, the annual expected outage cost has dropped by almost 94%.

Table 9 illustrates that the annual benefits from the MDS are insignificant compared to the annual carrying costs of the switches. The performance of H24C/H26C is expected to be exceptionally good following the commissioning of Clarington TS with an expected annual cost of $15.37k-$46.12k, a very well improvement from the current system and at least 13 times more economical than the annual cost with the switches. With the inclusion of Clarington TS by 2018, the system is projected to be most cost-effective and reliable.

Table 9 **Cost Results, Overlap Line Outages (H24C/H26C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a	$0.00	$263.52-$790.56	$263.52-$790.56
Option 1b	$0.00	$15.37-$46.12	$15.37-$46.12
Option 2	$600.00	$3.66-$10.97	$603.66-$610.97

6 Conclusion

6.1 Common Mode Outages

The following concluding remarks can be made regarding the impact of the common mode outages:

i) All options have the same frequency of supply interruptions to customers.
ii) Only one common mode outage, relative to this assessment, has occurred in the eastern Ontario in the past 25 years. This event occurred in 1992 due to high winds toppling multiple towers.
iii) The reliability and cost analysis show that it is not justifiable to invest $24M for marginal improvement.

6.2 Overlap Outages

The following concluding remarks can be made regarding the impact of overlap outages:

i) A significant improvement in reliability is observed after the commissioning of Clarington TS in 2018, Option 1b. However, the installation of MDS, Option 2, does not result in a substantial improvement in the reliability indices for an additional cost of approximately $24M.
ii) The result of reliability/cost analysis for circuits B23C/M29C is expected to be similar to H24C/H26C due to similar regional characteristics and loading conditions, therefore, same conclusion can be drawn for both pairs.

6.3 Summary

Based on historical data and a technical analysis on how outages impact the loads supplied by the GTA East 230kV corridor currently, post-Clarington TS, and with MDS, Table 10 illustrates that Clarington TS alone improves the reliability in the region by 77.8% while with additional investment of $24M in MDS, further reliability improvement is insignificant (less than 4%).

Table 10 **Summary of Results**

Options	Total Annual Cost ($k)	Annual Frequency of Interruption	% Reliability Improvement
Option 1a, Current System	$632.16-$1,896.49	0.02364	-
Option 1b, post Clarington TS	$101.28-$303.87	0.00524	77.8%
Option 2, MDS post Clarington TS	$1,211.47-$1,234.37	0.00444	81.2%

In conclusion, the performance of all 4 circuits has been very good over the last 20 years. With Clarington TS in service in 2018 the risk exposure on these circuits will be significantly less; therefore, it is not justifiable to further invest $24M.

Finally, these costs will have to be recovered from the customers or rate payers consistent with the TSC. Furthermore, MDS were considered to be ideal and 100% reliable in the course of this assessment but in reality introduce a weak link in the system.

WG is recommending that based on this assessment, Option 1b is considered to be the most economical and reliable state of the system. No further action is required at this time.

7 Next Steps

Hydro One will continue with the Clarington TS and keep the LDCs informed of any delays with the project. The finding of this study will be included in the GTA East RIP report expected to be completed in Q4 2016.

8 References

[1] Line Switches Reliability Study by Gomaa HAMOUD, Hydro One – May, 2016
[2] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May, 2013
[3] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)
[4] GTA East Needs Assessment Report – April, 2013
[5] GTA East Integrated Regional Resource Plan (IRRP) Report – June, 2016

GTA North

Regional Infrastructure Plan

February 5, 2016

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Enersource Hydro Mississauga Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Newmarket-Tay Power Distribution Ltd.
PowerStream Inc.
Toronto Hydro Electric System Ltd.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE ("TSC") REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN FACILITIES THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS OF THE GTA NORTH REGION.

The participants of the RIP Working Group included members from the following organizations:

- Enersource Hydro Mississauga Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)Independent Electricity System Operator
- Newmarket-Tay Power Distribution Ltd.
- PowerStream Inc.
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB's mandated regional planning process for the GTA North Region which consists of the York Sub-Region and the Western Sub-Region. It follows the completion of the York Sub-Region's Integrated Regional Resource Planning ("IRRP") by the IESO in April 2015 and the Western Sub-Region's Needs Assessment ("NA") Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for the York Sub-Region over the near-term (up to 5 years) and the mid-term (5 to 10 years). The York Region IRRP has identified the need for additional transformation capacity in Markham, Northern York Region and Vaughan in the mid-term. These mid-term needs are linked to long-term (beyond 10 years) transmission capacity needs.

No needs have been identified over the near-term and mid-term for the Western Sub-Region except for load restoration for the loss of double circuit 230 kV line V43/V44. It is recommended that this need be assessed as part of the IESO led GTA West bulk system planning initiative and as a result is not addressed in this RIP.

The major infrastructure investments planned for the GTA North Region over the near-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost
1	Vaughan #4 MTS	Q1 2017	$25M*
2	Holland breakers, disconnect switches and special protection scheme	Q4 2017	$32M
3	Parkway belt switches	Q4 2018	$4-6M

* PowerStream's station cost. Hydro One line connection cost is currently being estimated

The planning is continuing for the mid-term and long-term needs. These needs, and the options to address these them, are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through the Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA NORTH REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Enersource Hydro Mississauga Inc. ("Enersource"), Hydro One Brampton Networks Inc. ("Hydro One Brampton"), Hydro One Distribution, Newmarket-Tay Power Distribution Ltd. ("NTPDL"), PowerStream Inc. ("PowerStream"), Toronto Hydro-Electric System Limited ("THESL"), and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA North Region includes most of the Regional Municipality of York and parts of the City of Toronto, Brampton, and Mississauga (see Figure 1-1). Electrical supply to the Region is provided through 230 kV transmission circuits, fifteen step-down transformer stations ("TS"), and the York Energy Centre ("YEC") generating station ("GS").

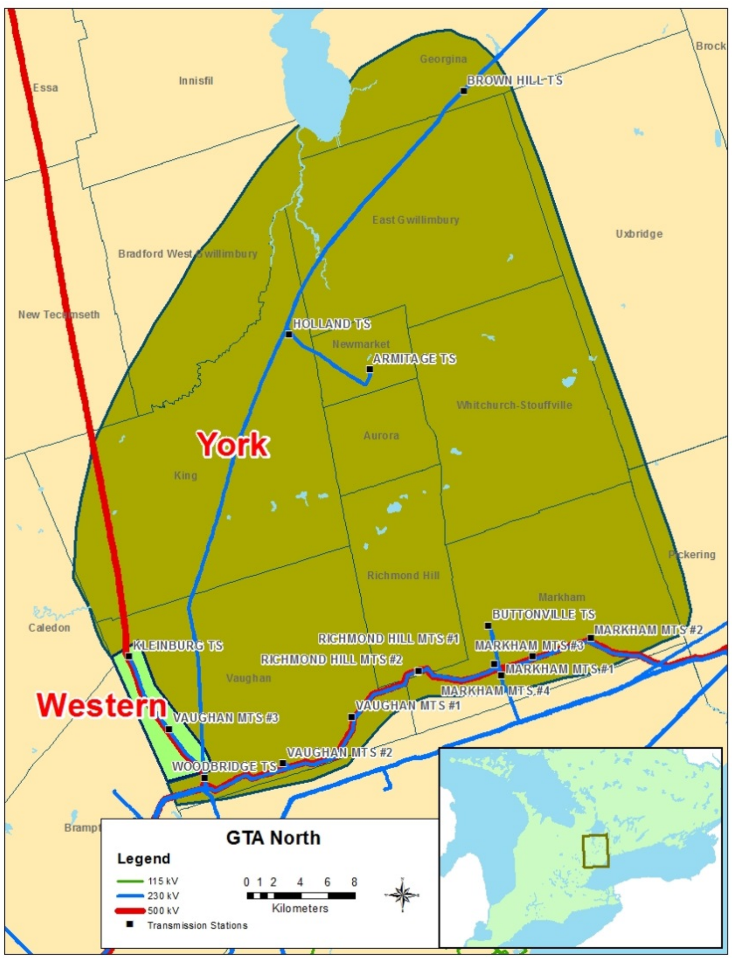

Figure 1-1 GTA North Region

1.1 Scope and Objectives

This RIP report examines the needs in the GTA North Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plan to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2015 to 2025) identified in previous planning phases (Needs Assessment and Integrated Regional Resource Plan)
- Identification of any new needs over the 2015-2025 period and a wires plan to address them.
- Consideration of long-term needs identified in the York Region IRRP

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the regional needs.
- Section 7 describes the needs and provides alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2 REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led

[1] Also referred to as Needs Screening.

stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- NA, SA, and LP phases of regional planning; and,
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

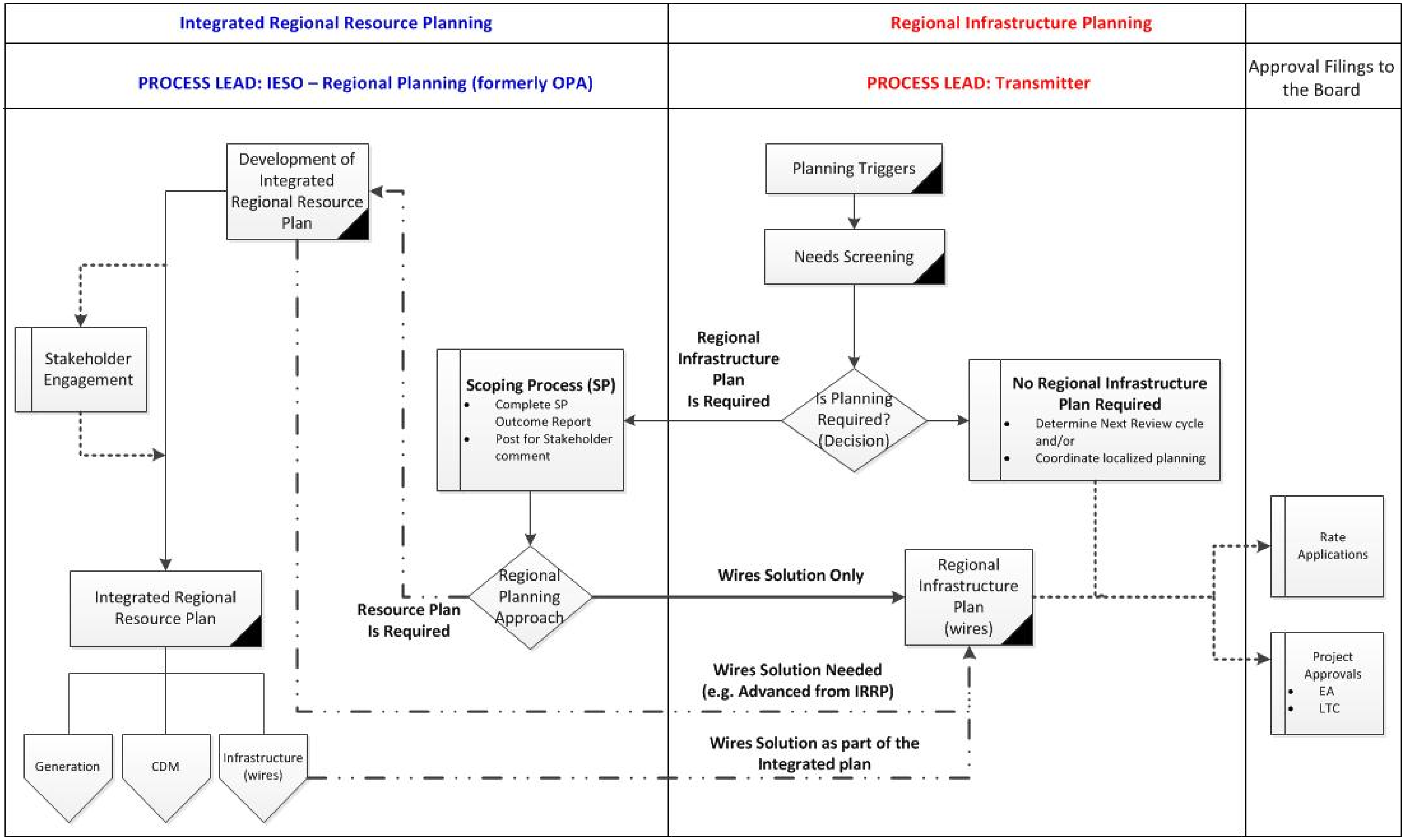

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any DG or CDM programs.
   - Existing area network and capabilities including any bulk system power flow assumptions; and,
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

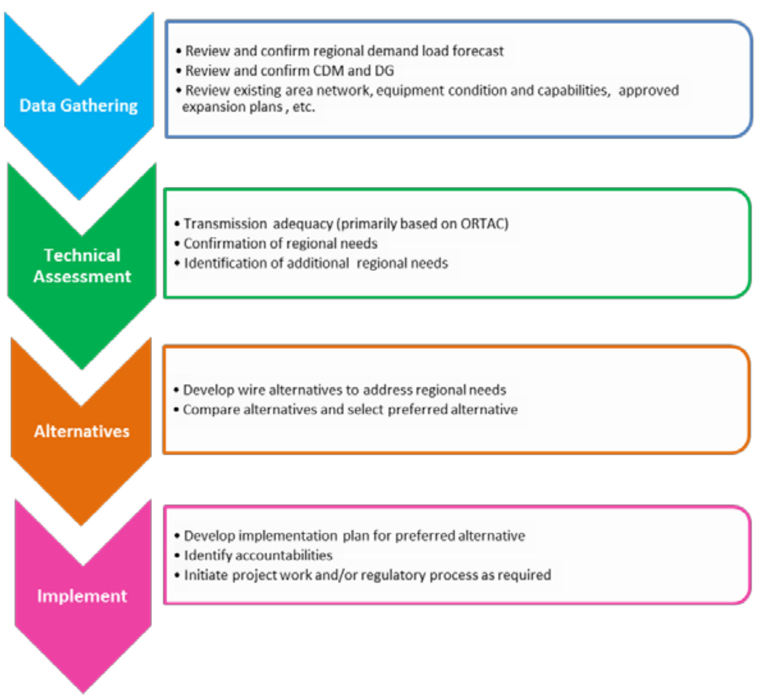

Figure 2-2 RIP Methodology

3 REGIONAL CHARACTERISTICS

THE GTA NORTH REGION IS COMPRISED OF THE YORK SUB-REGION AND THE WESTERN SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIFTEEN 230 KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1900MW.

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B82V/B83V in King Township.

The April 2015 York Region Integrated Regional Resource Plan ("IRRP"), prepared by the IESO in conjunction with Hydro One, PowerStream and Newmarket-Tay Power, focused solely on the York Sub-Region. The June 2014 GTA North Western Sub-Region Needs Assessment report, prepared by Hydro One, considered the Western Sub-Region. A map of the GTA North Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 York Sub-Region

The York Sub-Region was identified as a "transitional" region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

For regional planning purposes, the York Sub-Region is further classified into Northern York Area and Southern York Area to reflect the layout of the region's electricity infrastructure. The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and three 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and PowerStream.

The Southern York Area includes the municipalities of Vaughan, Markham and Richmond Hill. It is supplied by three 500/230 kV autotransformer stations (Claireville TS, Parkway TS, and Cherrywood TS), nine 230 kV transformer stations (includes eight municipal transformer stations) stepping down the voltage to 27.6 kV, and one other direct transmission connected load customer. The LDC supplied in the Southern York Area is PowerStream.

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Western Sub-Region

The Western Sub-Region comprises the Western portion of the municipality of Vaughan. Electrical supply to the sub-region is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV tap (namely, the "Kleinburg tap") that supplies three 230 kV transformer stations (including one municipal transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied in the sub-region are PowerStream and Hydro One Distribution. Embedded LDCs supplied in the sub-region include Enersource, Hydro One Brampton and Toronto Hydro.
During the Needs Assessment phase for the Western Sub-Region, a load restoration need for the loss of V43/V44 was identified. It was recommended that a plan to address this need be included in the IESO led GTA West bulk system planning initiative and therefore this need is not addressed in this RIP.

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

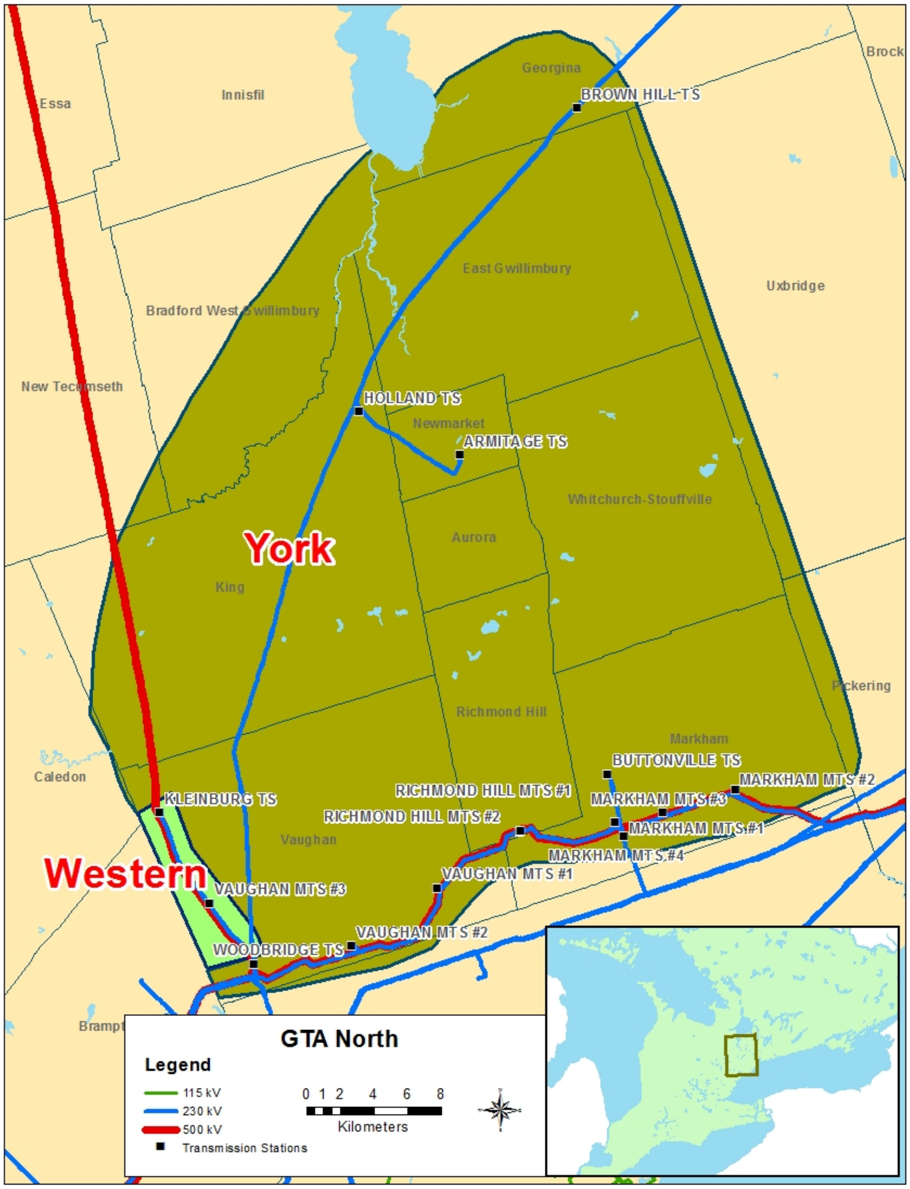

Figure 3-1 GTA North Region – Supply Areas

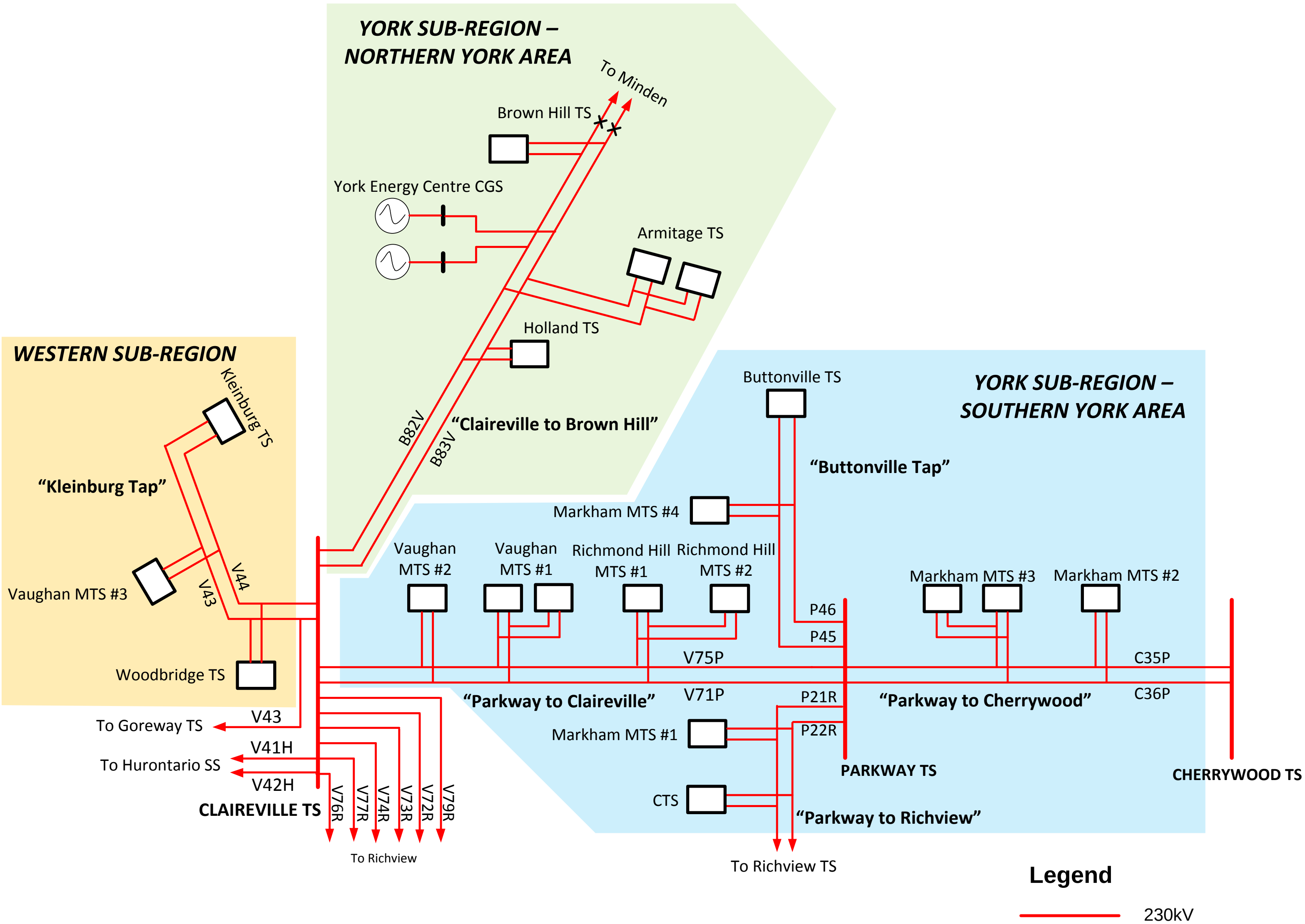

Figure 3-2 GTA North Transmission Single Line Diagram

4 TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GTA NORTH REGION.

A brief listing of the completed development projects along with their in-service dates over the last 10 years is given below:

- Holland TS and low voltage capacitor banks (2009) – to increase transformation capacity for the Northern York Area.
- Parkway 500-230kV autotransformer station (2006) – to increase transmission supply capacity to GTA North
- Parkway x Richmond Hill 230kV double circuit line (2006) – to improve reliability of supply to Southern York Area
- Connect Markham #4 MTS (2009) – to increase transformation capacity for the Southern York Area.
- Increased the size of the capacitor banks at Armitage TS (2006) – to improve reliability of supply to the Northern York Area.
- Connect the York Energy Centre generation facility (2012) – to provide a local source of supply for the Northern York Area.

The following development projects are currently underway:

- Vaughan MTS #4 (2017) – to increase transformation capacity for the Southern York Area.
- Holland breakers, disconnect switches and special protection scheme (2017) – to increase the transmission supply capacity and load restoration capability of the York Sub-Region.

5 FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA North Region is forecast to increase at an average rate of approximately 2.1% annually up 2020, and 1.8% between 2020 and 2025. The growth rate varies across the Region.

Figure 5-1 shows the GTA North Region extreme summer weather coincident peak net load forecast. The coincident peak net load forecast for the individual stations in the GTA North Region is given in Appendix D. The net load forecast takes into account the expected impacts of conservation programs and distributed generation resources.

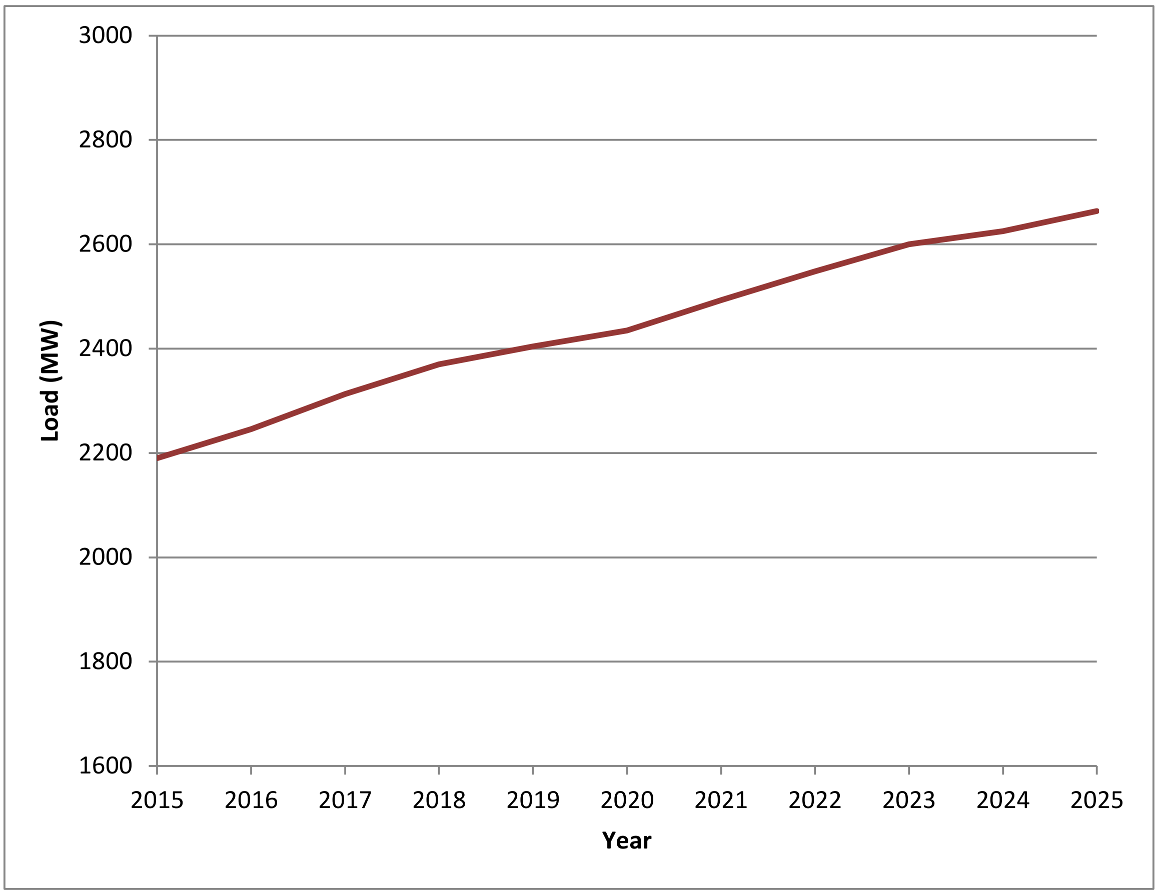

Figure 5-1 GTA North Region Extreme Summer Weather Coincident Peak Net Load Forecast

The station coincident peak net loads used in the RIP are as given in the York Region IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region[2]. RIP Working Group participants confirmed that the load forecast, CDM, and DG information used in the IRRP and NA for the Western Sub-Region was still valid.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP Assessments is 2015-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor which is consistent with ORTAC[4]. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6 ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE GTA NORTH REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle two regional assessments have been conducted for the GTA North Region; the findings of these studies are input to the RIP:

1) IESO's York Region Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – GTA North – Western Sub-Region – June 27, 2014[2]

The York region IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Holland TS Breakers project and the Vaughan #4 MTS project were initiated to provide adequate load supply capability for the York Sub-Region while the York Region IRRP study was still underway. A detailed description and status of the Holland TS Breakers project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the GTA North Region assuming the Holland TS Breakers project is in-service using the latest Regional Forecast based on the IRRP load growth scenario as given in Section 5. Sections 6.1- 6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Mid-Term Needs in the GTA North Region

Type	Section	Needs	Timing
Step-down Transformation Capacity	7.1.1	Additional transformation capacity in Vaughan (new Vaughan MTS #4 on circuits B82V/B83V)	2017
	7.1.4	Additional transformation capacity in Markham	2022(3)
	7.1.3	Additional transformation capacity in Vaughan(1)	2023(3)
	7.2.2	Additional transformation capacity in Northern York Area(1)	2023
Transmission Capacity	7.2.1	Capacity of the Claireville to Brown Hill (B82V/B83V) transmission line exceeded	2021
Load Security	7.2.1	Claireville to Brown Hill line (B82V/B83V)	2018
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
Load Restoration	7.2.1	Claireville to Brown Hill line (B82V/B83V)	Today
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
	7.3.1	Claireville to Kleinburg line (V43/V44) – restoration need only(2)	Today

(1) There are long-term transmission supply needs associated with new transformation capacity
(2) Restoration need to be assessed as part of the IESO led GTA West bulk system planning initiative
(3) PowerStream is currently reviewing their forecast and has advised that the need date for Markham may change to 2023 and the need date for Vaughan may change to 2026.

6.1 Adequacy of York Sub-Region Facilities

6.1.1 500 and 230 kV Transmission Facilities

All 500 and 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The York Sub-Region is comprised of the following 230 kV circuits. Refer to Figure 3-2.

Southern York Area:

a) Parkway TS to Cherrywood TS 230 kV circuits: C35P and C36P.
b) Parkway TS to Claireville TS 230 kV circuits: V71P and V75P.
c) Parkway TS to Buttonville TS **(**"Buttonville Tap") 230 kV circuits: P45 and P46.
d) Parkway TS to Richview TS 230 kV circuits: P21R and P22R.

Northern York Area:

- Claireville TS to Brown Hill TS 230 kV circuits: B82V and B83V.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period.

6.1.2 Step down Transformer Station Facilities

There are a total of twelve step-down transformers stations in the York Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in the York Sub-Region

Northern York Area		
Armitage TS	Brown Hill TS	Holland TS
Southern York Area		
Buttonville TS	Markham MTS#1*	Markham MTS#2*
Markham MTS#3*	Markham MTS#4*	Richmond Hill MTS*
Vaughan MTS#1*	Vaughan MTS#2*	Industrial Customer

*Stations owned by PowerStream

Based on the LTR of these load stations, additional capacity is required in Vaughan in 2017 which will be addressed by Vaughan MTS #4. Based on the forecast in Appendix D, additional capacity is required in Markham as early as 2022, and additional capacity will be needed in both Vaughan and Northern York Area as early as 2023. However, PowerStream has advised that their forecast for Markham and Vaughan is currently under review, and that these need dates may change to 2023 and 2026 respectively.

The station loading in each area and the associated station capacity and need dates are summarized in Table 6-3.

Table 6-3 Adequacy of the Step-Down Transformation Facilities in the York Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)*	Need Date
Northern York Area (Armitage, Holland)	485	430	2023
Northern York Area (Brown Hill)	184	74	-
Southern York Area (Markham/Richmond Hill)	956	833	2022
Southern York Area (Vaughan)	612**	459	2023

* Weather adjusted summer peak as per York Region IRRP

** Includes future capacity provided by Vaughan #4 MTS. It does not include Vaughan MTS #3 which is in the Western Sub-Region

6.2 Adequacy of Western Sub-Region Facilities

The Western Sub-Region is comprised of one 230 kV double circuit line V43/V44 between Claireville TS and Kleinburg TS. Refer to Figure 3-2. The line supplies Kleinburg TS, Vaughan MTS #3, and Woodbridge TS. Loading on the V43/V44 line is adequate over the study period.

6.2.1 Step down Transformation Facilities

There are three step-down transmission connected transformation stations in the York Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in the Western Sub-Region

Kleinburg TS
Woodbridge TS
Vaughan MTS#3*

*Station owned by PowerStream

The forecast individual station forecast loads are given in Appendix D. Based on the forecast loads these transformer stations are adequate over the study period. The total station capacity and 2015 loads in Western Sub-Region are given in Table 6-5.

Table 6-5 Adequacy of Step-Down Transformation Facilities – Western Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)	2025 Summer Loading (MW)
Western Sub-Region (Vaughan/Kleinburg)	509	394	409

6.3 Other Items Identified During Regional Planning

6.3.1 Load Security and Restoration in the Southern York Area

The York Region IRRP report had identified load security and restoration needs for loss of the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P. Loading on the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P exceeds the 600 MW limit as per ORTAC security criteria. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Working Group recommendations to address the needs are discussed in more detail in Section 7.1.2.

6.3.2 Load Restoration in Western Sub-Region

The Needs Assessment report for the Western Sub-Region had identified a load restoration need for the loss of the Claireville TS to Kleinburg TS 230 kV double circuit line V43/V44. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The Working Group has reviewed the need and reaffirmed the NA recommendation that this need be considered as part of the IESO led GTA West bulk system planning initiative.

6.4 Long-Term Regional Needs

As shown in Section 6.1.2 additional transformation capacity is required in the mid-term. With continued demand growth, the transmission system supplying these stations is also expected to reach its limits. The York Region IRRP had identified the need to coordinate the long term transmission needs with plans to address the station capacity needs.

The GO Rail Electrification Project is an initiative by Metrolinx to convert several rail corridors from a diesel to an electric-based system. GO's Barrie and Stouffville corridors are part of this plan and it is expected that parts of these rail corridors will be supplied by transmission infrastructure in the GTA North Region. At the time of this RIP the electrification project is still in the planning phase, but the impact of this project on the electrical infrastructure in the GTA North Region will need to be monitored as the plans are developed.

The options to address the transformation capacity needs are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through a Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

7 REGIONAL PLANS

This section discusses the needs, wires alternatives and the current preferred wires solution for addressing the electrical supply needs in the GTA North Region. These needs are listed in Table 6-1 and include needs previously identified in the IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region.[2] Needs for which work is already underway are also included.

The near-term needs include needs that arise over the first five years of the study period (2015 to 2020) and the mid-term needs cover the second half of the study period (2020-2025).

7.1 Southern York Area

7.1.1 Increase Transformation Capacity in Vaughan

7.1.1.1 Description

The load forecast reflects substantial growth around the City of Vaughan, mainly around the northern boundaries, as new developments are being made in the area. As a result, based on the net demand forecast a new transformer station is needed by 2017 to ensure adequate transformation capacity is available. This need was also identified as a near-term need in the 2015 York Region IRRP.

7.1.1.2 Recommended Plan and Current Status

Due to the need to provide transformation capacity by 2017, work on building a new station was initiated by PowerStream while the York Region IRRP was still under way. The IRRP Working Group recommended that the new station connect to the Claireville to Brown Hill lines (230 kV circuits B82V/B83V) approximately 12 km north of Claireville TS.[5] Refer to Figure 7.1.

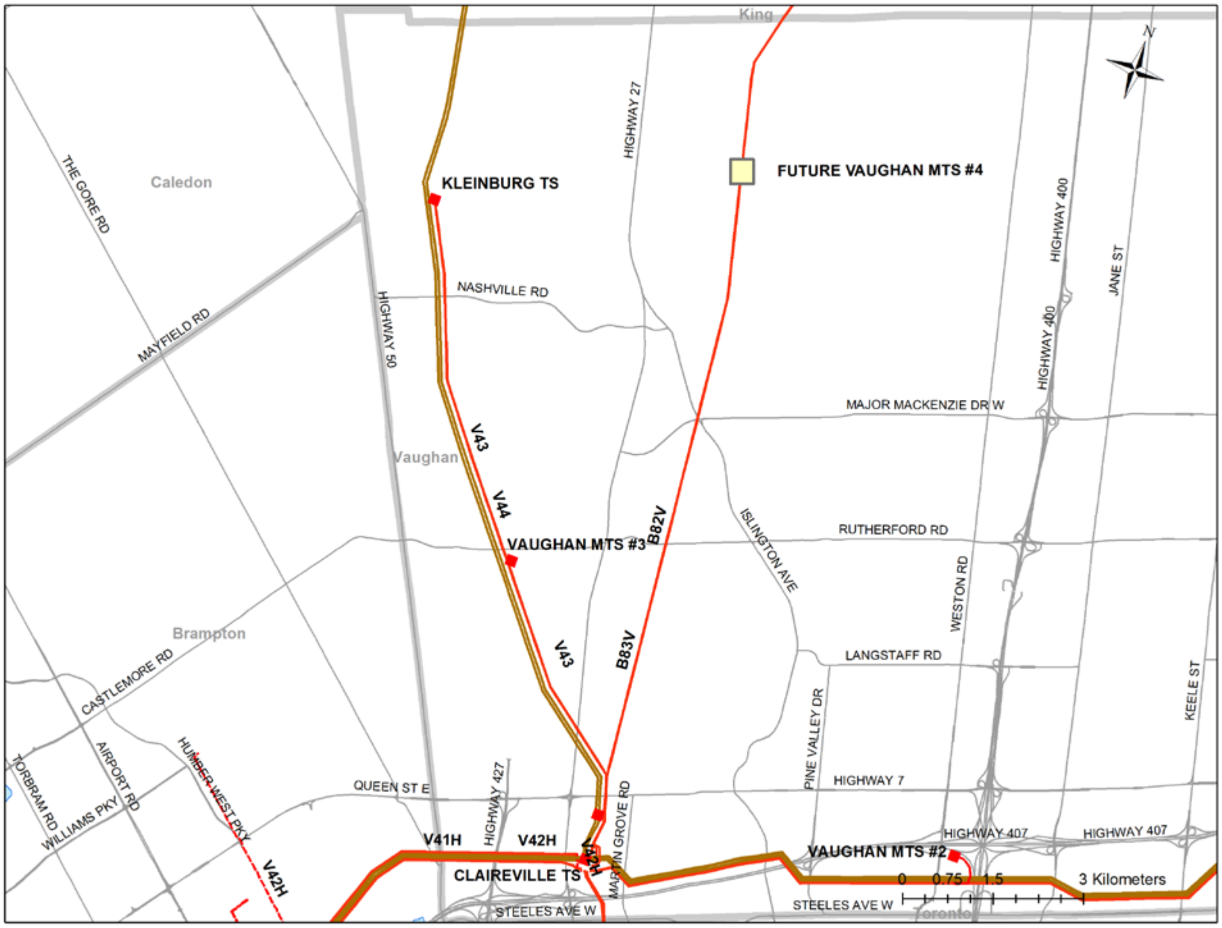

Figure 7-1 Vaughan MTS #4

The new station, Vaughan MTS #4, will provide 153 MW of 27.6 kV transformation capacity and is expected to be in-service by May 2017. Hydro One will construct the line tap to connect the new station to the B82V/B83V circuits.

PowerStream's estimated cost for the station is $25M. The Hydro One line connection cost is currently being estimated. The Hydro One line connection cost will be recovered from rate revenue in accordance with the TSC.

7.1.2 Improve Load Restoration Capability on the Parkway to Claireville Line

7.1.2.1 Description

The Parkway to Claireville line (V71P/V75P) is located on the Parkway Belt and supplies five load stations with a combined load of approximately 700 MW under current summer peak loading conditions. There are two needs identified for this system:

- The load security criteria in ORTAC[4] limits the amount of load that can be interrupted due to the loss of two elements (e.g.: a double circuit line outage) to 600 MW under peak load. On the Parkway to Claireville line, that limit is exceeded.
- The load restoration criteria requires that any load that is interrupted that exceeds 250 MW must be restorable within 30 minutes. At present, this may not be possible on the Parkway to Claireville line under certain operating conditions.

7.1.2.2 Recommended Plan and Current Status

The York Region IRRP recommended the installation of inline switches at the Vaughan MTS #1 junction in order to improve the capability of the system to restore load in the event that both 230 kV circuits V71P/V75P are lost. The switches will not reduce the amount of load that is interrupted, however they will enable Hydro One to quickly isolate the problem and allow the resupply of load to occur expeditiously. This work is covered under the V71P/V75P - Install 230 kV In-line Switches project.

Hydro One has established a project to install the two 230 kV in-line switches onto the V71P/V75P double circuit line with one switch installed on each circuit. The project is currently in the detailed design and estimation phase. The cost of this project is approximately $4-6 million and it is anticipated to be a transmission pool investment. The planned in-service date is May 2018.

7.1.3 Mid-Term Need to Increase Transformation Capacity in Vaughan

7.1.3.1 Description

The planned Vaughan MTS #4 will provide near term transformation capacity for Vaughan beginning in 2017. However, the load forecast shows that additional transformation capacity will be needed in Vaughan as early as 2023. There isn't sufficient transmission capacity available to supply another transformation station on the Claireville to Brown Hill line. Therefore a plan to increase transmission capacity to the area will be required before a plan for a new transformation station can be committed.

7.1.3.2 Recommended Plan and Current Status

Given the time required to build new transmission facilities, the York Region IRRP[1] had advised that it was necessary to identify a preferred alternative no later than 2018 to address both the transformation capacity need as well as the transmission capacity need. However, PowerStream is currently reviewing their load forecast for Vaughan and has advised that the need date for new transformation capacity may change to 2026. An update to the York Region IRRP is currently scheduled for 2017 to review the need date and develop a preferred plan for building and connecting additional transformation capacity in Vaughan.

7.1.4 Mid-Term Need to Increase Step-Down Transformation Capacity in Markham

7.1.4.1 Description

The step-down transformation capacity in Markham will be exceeded as early as 2022. The York Region IRRP has identified that additional transmission facilities will be required to supply the new station. It is expected that the IESO will continue to explore non-wires options, in addition to wires options, through the IRRP process.

New developments attributable to forecasted load growth in the area are generally further north, away from existing transmission facilities. The ORTAC's[4] load restoration criteria will need to be considered in the further development of any detailed wires options. Non-wires options are beyond the scope of this RIP, but there are two main wires options for supplying a new Markham transformer station.

Option 1 - Connect to 230kV circuits C35P/C36P between Parkway TS and Cherrywood TS
The Parkway to Cherrywood line (C35P/C36P) connects two major bulk transmission stations, Parkway TS and Cherrywood TS, and also supplies load stations Markham MTS #3 (2 stations) and Markham MTS #2. There is transmission capacity available on these circuits to connect another transformer station.

Option 2 – Connect to 230kV double circuit line P45/P46 between Parkway TS and Buttonville TS
The Buttonville Tap (P45/P46) currently supplies two stations, Markham MTS #4 and Buttonville TS radially from Parkway TS. The transmission capacity on these circuits is thermally limited by a section less than 1 km long, so it would be necessary to increase the thermal capacity of these circuits in order to fully supply another station.

Extending the transmission circuits discussed would allow the point of supply to be nearer to the area of expected load growth and therefore reduce the amount of distribution facilities that would be needed.

7.1.4.2 Recommended Plan and Current Status

The existing transmission lines are not near the areas of expected load growth so the additional transmission costs to supply a new station nearer to the load need to be considered alongside the distribution costs. PowerStream estimates the incremental distribution costs for a station supplied by existing transmission lines to be on the order of $10-$50M higher than would be required for a station located nearer to the load.

Given that this need is a mid-term need, the York Region IRRP[1] identified a number of non-wires approaches that may address or defer the need for further transformation capacity. Such alternatives include CDM, DG, large generation and other local community initiatives and further monitoring of the load growth was recommended. In order to have facilities in-service to meet a summer 2022 need, it is recommended to continue wires planning, in addition to other non-wires alternatives, to meet this need and to identify a preferred solution by the end of 2017. This timeline allows approximately 4.5 years for detailed estimating, engineering, approvals, construction and commissioning if a wires option is identified as the preferred alternative. However, PowerStream is currently reviewing their load forecast for Markham and has advised that the need date for new transformation capacity may change to 2023. It is expected that the need date will be reviewed and a preferred solution will be identified in the York Region IRRP update process which is currently scheduled for 2017.

7.2 Northern York Area

7.2.1 Increase Capacity and Load Restoration Capability on Claireville to Brown Hill Line

The transmission capacity, load security and load restoration requirements are near-term needs for the Claireville to Brown Hill line (circuits B82V/B83V). These needs were identified in the 2015 York Region IRRP[1]. The Claireville to Brown Hill transmission line and local generation (York Energy Centre) combined are capable of supplying 600 MW of load. This limit is based on the ORTAC[4] load security criteria, which limits the amount of load that can be lost for two elements out of service to 600 MW. This is the most restrictive limit in this system and therefore defines the amount of load that can be supplied. With continued load growth at the stations supplied by this line as well as the future Vaughan #4 MTS (described in section 7.1), it is expected that load security criteria will be exceeded by 2018 based on the net demand forecast.

The load restoration need is based on the ORTAC[4] load restoration criteria that requires any load lost exceeding 250 MW to be restorable within 30 minutes. Based on the current net peak demand forecast, the loss of the Claireville to Brown Hill line will exceed this threshold and there are insufficient transmission and distribution facilities to restore sufficient load within 30 minutes in order to respect the criteria.

7.2.1.1 Recommended Plan and Current Status

Hydro One is expanding the Holland TS station to include two, 230kV inline circuit breakers and six motorized disconnect switches to increase the transmission capacity as well as the load restoration capability of this system. The project includes a load rejection and generation rejection special protection scheme ("SPS"). The purpose of the SPS is to ensure that the transmission system does not get overloaded following respected contingencies. The IESO (formerly the Ontario Power Authority) stated their support for this project in a letter to Hydro One dated June 14, 2013.[5] The planned in-service date for this project is Q4 2017 at an estimated cost of $32 million. This is anticipated to be a transmission pool cost and LDCs are not expected to pay any contribution.

The station service supply to the York Energy Centre is currently supplied from Holland TS. However, a low-voltage breaker failure event at Holland TS or a double circuit 230 kV contingency can result in an interruption to the station service supply to York Energy Centre and therefore the loss of all generation output until the station service can be restored from the alternate source. The IESO intends to develop a plan to address this issue in the York Region IRRP update currently scheduled for 2017.

7.2.2 Mid-Term Need to Increase Transformation Capacity

Based on the growth forecast for the Northern York Area, the combined loading on Armitage TS and Holland TS will exceed their combined summer 10-Day LTR as early as 2023. There is 44 kV transfer capability between these stations on the distribution system so the timing of the need is based on the combined capability of both stations. The IRRP indicated that the Claireville to Brown Hill circuits do not have sufficient capacity to fully supply another transformation station in Northern York Area after the Vaughan #4 MTS connection and Holland breakers project and therefore there is a long-term need to increase transmission capability to supply a new station. However, as noted in the York Region IRRP, under a low growth scenario in the long term, the demand in Northern York Area will stabilize to within the capacity of existing stations to beyond 2033.

7.2.2.1 Recommended Plan and Current Status

The York Region IRRP[1] identified a number of non-wires alternatives that may address or defer the need for further transformation capacity in Northern York Area. Such alternatives include CDM, DG, large generation and other local community initiatives. However, given that the need date for this area may be as early as 2023, it is necessary to identify a preferred alternative by 2018 that addresses both the transformation capacity need as well as the transmission capacity need. The working group expects to finalize a plan and recommendations to address these needs in an IRRP update currently scheduled for 2017.

7.3 Western Sub-Region

7.3.1 Load Restoration Need for the Claireville to Kleinburg Line

The three stations in this sub-region, Woodbridge TS, Vaughan #3 MTS and Kleinburg TS, are supplied by two radial 230kV circuits, V43 and V44, originating from Claireville TS. Inherent to radial configuration, the loss of these two circuits will interrupt supply to loads and consequently load restoration times as per the ORTAC[4] may not be met. This need was identified during the NA for this sub-region and also in the Northwest GTA IRRP[6] and it was subsequently recommended that this need be addressed in the IESO's GTA West bulk system planning initiative.

7.4 Long Term Future Transmission Corridor to the GTA North Region

The GTA West RIP recommended the establishment of a future-use transmission corridor, to address growth-related needs in the GTA West region. In addition to addressing needs in the GTA West region, development of an eastern portion of this corridor through the City of Vaughan is also a possible option that could address the long-term supply needs identified for York Region. It is therefore recommended that, in the development of the long-term plans for the GTA West and GTA North regions, consideration be given to coordinating solutions to meet the needs of both regions when assessing options for each region individually.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA NORTH REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in Table 8-1.

Table 8-1: Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Vaughan Transformation Capacity (Near Term)
II	Northern York Area Load Security on B82V/B83V
III	Northern York Area Load Restoration on B82V/B83V
IV	Parkway to Claireville – Load Security on V71P/V75P
V	Parkway to Claireville – Load Restoration on V71P/V75P
VI	Markham Transformation Capacity (Mid-term)
VII	Vaughan Transformation Capacity (Mid-term)
VIII	Northern York Area Transformation Capacity (Mid-term)
IX	Kleinburg Tap – Load Restoration on V43/V44

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the needs are summarized in Table 8-2 below. Investments to address the needs where there is time to make a decision (Needs No. VI, VII, and VIII), will be reviewed and finalized in the next regional planning cycle. Need No. IX will be addressed in the IESO GTA West bulk system planning initiative.

Table 8-2: Regional Plans – Next Steps, Lead Responsibility and Planned In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Estimated Cost	Needs Mitigated
1	Vaughan #4 MTS	LDC to carry out the work	PowerStream	2017	$25M	I
2	Holland Breakers and SPS	Transmitter to carry out the work	Hydro One	2017	$32M	II, III
3	Parkway Belt Switches	Transmitter to carry out the work	Hydro One	2018	$4-6M	V

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs, the IRRP proposed that the process be updated in advance of the regular 5-year review schedule. The York Region IRRP is currently scheduled to be updated in 2017.

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[4]. Independent Electricity System Operator, "Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0"
http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

[5]. Hydro One, "OPA Letter – Initiating Near-Term Transmission Components of the York Region Integrated Regional Resource Plan," 14 June 2013.
http://www.hydroone.com/RegionalPlanning/GTANorth/Documents/OPA%20Letter%20to%20Hydro%20One%20%20Regarding%20%20York%20Subregion.pdf

[6]. Independent Electricity System Operator, "Northwest Greater Toronto Area Integrated Regional Resource Plan", 28 April 2015
http://www.ieso.ca/Documents/Regional-Planning/GTA_West/2015-Northwest-GTA-IRRP-Report.pdf

APPENDIX A: STATIONS IN THE GTA NORTH REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Kleinburg TS T1/T2 27.6 Kleinburg TS T1/T2 44	230/27.6 230/44	V43/V44
Vaughan MTS #3	230/27.6	V43/V44
Woodbridge TS T3/T5 27.6 Woodbridge TS T3/T5 44	230/27.6 230/44	V43/V44
Armitage TS T1/T2/T3/T4	230/44	B82V/B83V
Brown Hill TS T1/T2	230/44	B82V/B83V
Holland TS T1/T2	230/44	B82V/B83V
Buttonville TS T3/T4	230/27.6	P45/P46
Markham MTS #1	230/27.6	P21R/P22R
Markham MTS #2	230/27.6	C35P/C36P
Markham MTS #3 T1/T2/T3/T4	230/27.6	C35P/C36P
Markham MTS #4	230/27.6	P45/P46
Richmond Hill MTS #1	230/27.6	V71P/V75P
Richmond Hill MTS #2	230/27.6	V71P/V75P
Vaughan MTS #1 T1/T2/T3/T4	230/27.6	V71P/V75P
Vaughan MTS #2	230/27.6	V71P/V75P

APPENDIX B: TRANSMISSION LINES IN THE GTA NORTH REGION

Location	Circuit Designations	Voltage (kV)
Claireville TS to Brown Hill TS, Armitage TS and Holland TS	B82V/B83V	230
Claireville TS to Kleinburg TS, Vaughan MTS #3 and Woodbridge TS	V43/V44	230
Claireville TS to Vaughan MTS #1, Vaughan MTS #2, Richmond Hill MTS #1, Richmond Hill MTS #2, Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS and Markham MTS #4	P45/P46	230
Parkway TS to Markham MTS #2, Markham MTS #3, Cherrywood TS	C35P/C36P	230

APPENDIX C: DISTRIBUTORS IN THE GTA NORTH REGION

Distributor Name	Station Name	Connection Type	Area/Region
Enersource Hydro Mississauga Inc.	Woodbridge TS	Dx	Western Sub-Region
Hydro One Brampton Networks Inc.	Woodbridge TS	Dx	Western Sub-Region
Hydro One Networks Inc. (Distribution)	Armitage TS	Tx	Northern York Area
	Brown Hill TS	Tx	Northern York Area
	Holland TS	Tx	Northern York Area
	Kleinburg TS	Tx	Western Sub-Region
	Woodbridge TS	Tx	Western Sub-Region
Newmarket-Tay Power Distribution Ltd.	Armitage TS	Tx	Northern York Area
	Holland TS	Tx	Northern York Area
PowerStream Inc.	Armitage TS	Dx	Northern York Area
		Tx	Northern York Area
	Buttonville TS	Tx	Southern York Area
	Holland TS	Dx	Northern York Area
	Kleinburg TS	Tx	Western Sub-Region
	Markham MTS #1	Tx	Southern York Area
	Markham MTS #2	Tx	Southern York Area
	Markham MTS #3	Tx	Southern York Area
	Markham MTS #4	Tx	Southern York Area
	Richmond Hill MTS #1	Tx	Southern York Area
	Richmond Hill MTS #2	Tx	Southern York Area
	Vaughan MTS #1	Tx	Southern York Area
	Vaughan MTS #2	Tx	Southern York Area
	Vaughan MTS #3	Tx	Western Sub-Region
	Woodbridge TS	Dx	Western Sub-Region
		Tx	Western Sub-Region
PowerStream Inc.[Barrie]	Holland TS	Dx	Northern York Area
Toronto Hydro Electric System Limited	Woodbridge TS	Dx	Western Sub-Region
Veridian Connections Inc.	Armitage TS	Dx	Northern York Area

APPENDIX D: GTA NORTH REGION LOAD FORECAST 2015-2025

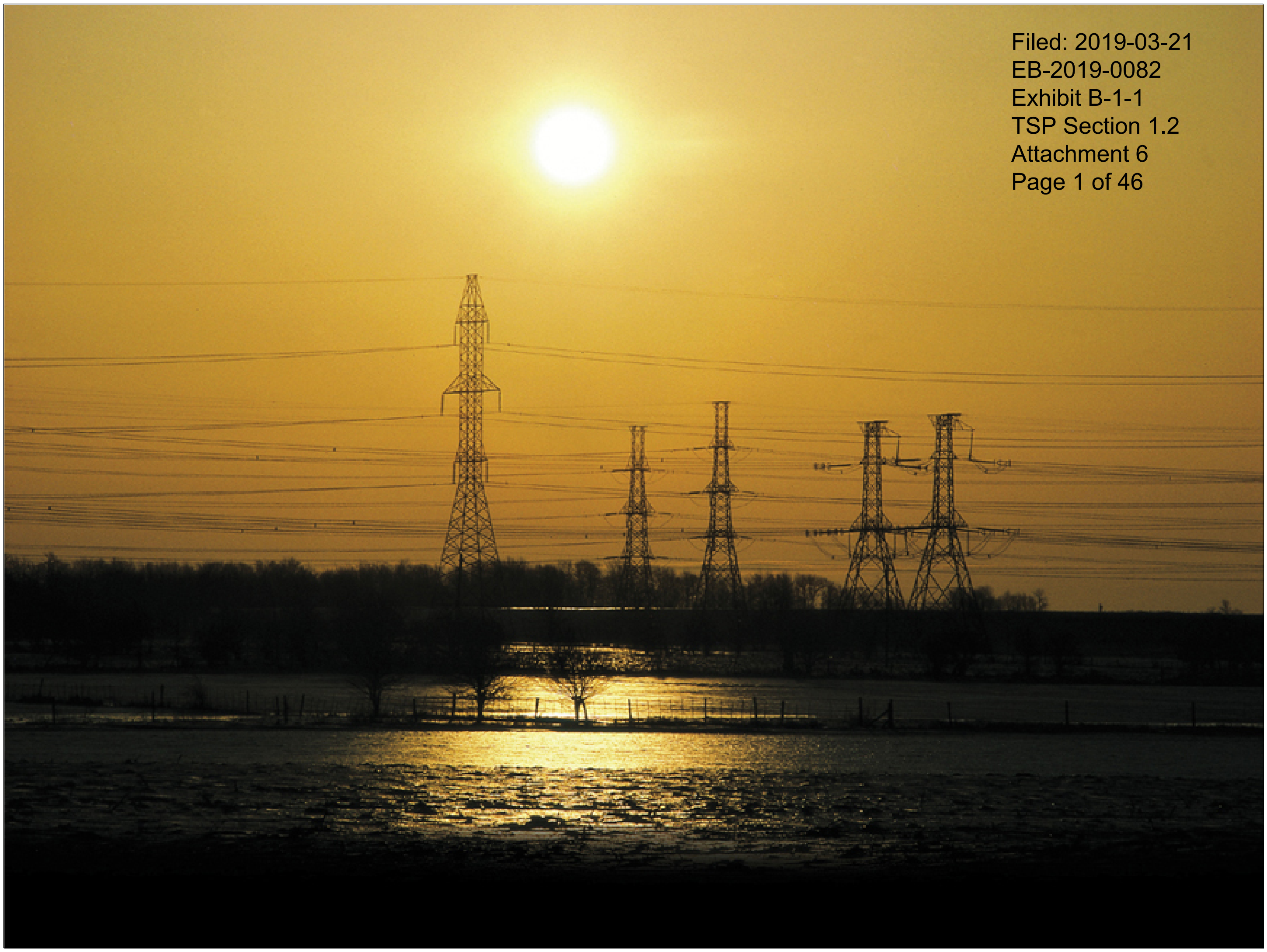
Stations Net Coincident Peak Load Forecast (MW)

Station Name	LTR*	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Kleinburg 28 kV (BY)	97	54	56	58	59	63	64	66	69	70	70	70
Kleinburg 44 kV (EQ)	99	62	63	64	65	65	65	65	66	66	66	66
Vaughan 3 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Woodbridge 44 kV (EQ)	80	53	54	54	54	53	52	52	52	52	52	52
Woodbridge 28 kV (BY)	80	72	71	71	71	70	69	69	68	68	68	68
Holland TS 44 kV	168	136	138	142	144	145	146	149	152	154	156	158
Armitage TS 44 kV	317	294	299	306	312	314	317	324	330	336	338	344
Brown Hill TS 44 kV	184	74	76	79	81	83	85	88	90	93	95	98
Richmond Hill MTS 28 kV	254	254	254	254	254	254	254	254	254	254	254	254
Vaughan 1 MTS 28 kV	306	306	306	306	306	306	306	306	306	306	306	306
Vaughan 2 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan 4 MTS	153	0	24	47	69	83	97	119	140	160	170	185
Buttonville TS 28 kV	166	153	153	153	153	153	153	153	153	153	153	153
Markham 1 MTS 28 kV	81	81	81	81	81	81	81	81	81	81	81	81
Markham 2 MTS 28 kV	101	101	101	101	101	101	101	101	101	101	101	101
Markham 3 MTS 28 kV	202	202	202	202	202	202	202	202	202	202	202	202
Markham 4 MTS 28 kV	153	42	62	89	112	125	137	158	178	198	207	220

* LTR based on 0.9 power factor

APPENDIX E: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme



GTA West

REGIONAL INFRASTRUCTURE PLAN

January 25, 2016

hydro one

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Burlington Hydro Electric Inc.
Enersource Hydro Mississauga Inc.
Halton Hills Hydro Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Milton Hydro Distribution Inc.
Oakville Hydro Electricity Distribution Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GTA WEST REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

This RIP is the final phase of the regional planning process and it follows the completion of the Northwest GTA Integrated Regional Resource Plan ("IRRP") in April 2015; and the GTA West Southern Sub-Region's Needs Assessment ("NA") and Scoping Assessment ("SA") in May 2014 and September 2014, respectively.

This RIP provides a consolidated summary of needs and recommended plans for both the Northern Sub-Region and Southern Sub-Region that make up the GTA West Region.

The major infrastructure investments planned for the GTA West Region over the near and medium-term (2016-2025), identified in the various phases of the regional planning process, are given in the table below with anticipated in-service date and estimated cost. Several long-term needs beyond 2026 have been identified, and further assessments are currently underway as part of the IESO Bulk System Study.

No.	Project	I/S Date	Cost
1	Build new Halton Hills Hydro MTS	2018	$19M (1)
2	Build new Halton TS #2	2020	$29M (1)
3	Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	2018-2019	$5M
4	Upgrade (reconductor) circuits H29/H30 (2)	2023-2026	$6.5M

Notes:

(1) Excludes cost for distribution infrastructure
(2) The plan will be reviewed and finalized in the next regional planning cycle

The following needs will be considered in the scope of the Bulk System Study led by the IESO:

- Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity need;
- Radial supply to Halton TS (T38/T39B) circuit capacity need;
- Supply security and restoration to several load pockets in GTA West Region.

The IESO's Northwest GTA IRRP has identified that Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow by 849-1132 MW by 2031, as forecast by the Province "Places to Grow" program. A new electricity corridor will be required for additional transmission facilities required to meet this long-term need in the area. The RIP Working Group recommends further assessments to be carried out and complete technical details, layout of high voltage electricity infrastructure no later than Q4 2016. Following this, Environmental Approval and acquisition of land rights would be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA WEST REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) (“Hydro One”) on behalf of the Working Group in accordance with the regional planning process established by the Ontario Energy Board (“OEB”) in 2013. The Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator (“IESO”)
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

The GTA West Region encompasses the municipalities of Brampton, southern Caledon, Halton Hills, Mississauga, Milton, and Oakville. The region includes the area roughly bordered geographically by Highway 27 to the north-east, Highway 427 to the south-east, Regional Road 25 to the west, King Street to the north and Lake Ontario to the south, as shown in Figure 1-1.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and 500/230 kV Trafalgar TS autotransformers, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. The summer 2015 peak load of the region was approximately 2900 MW.

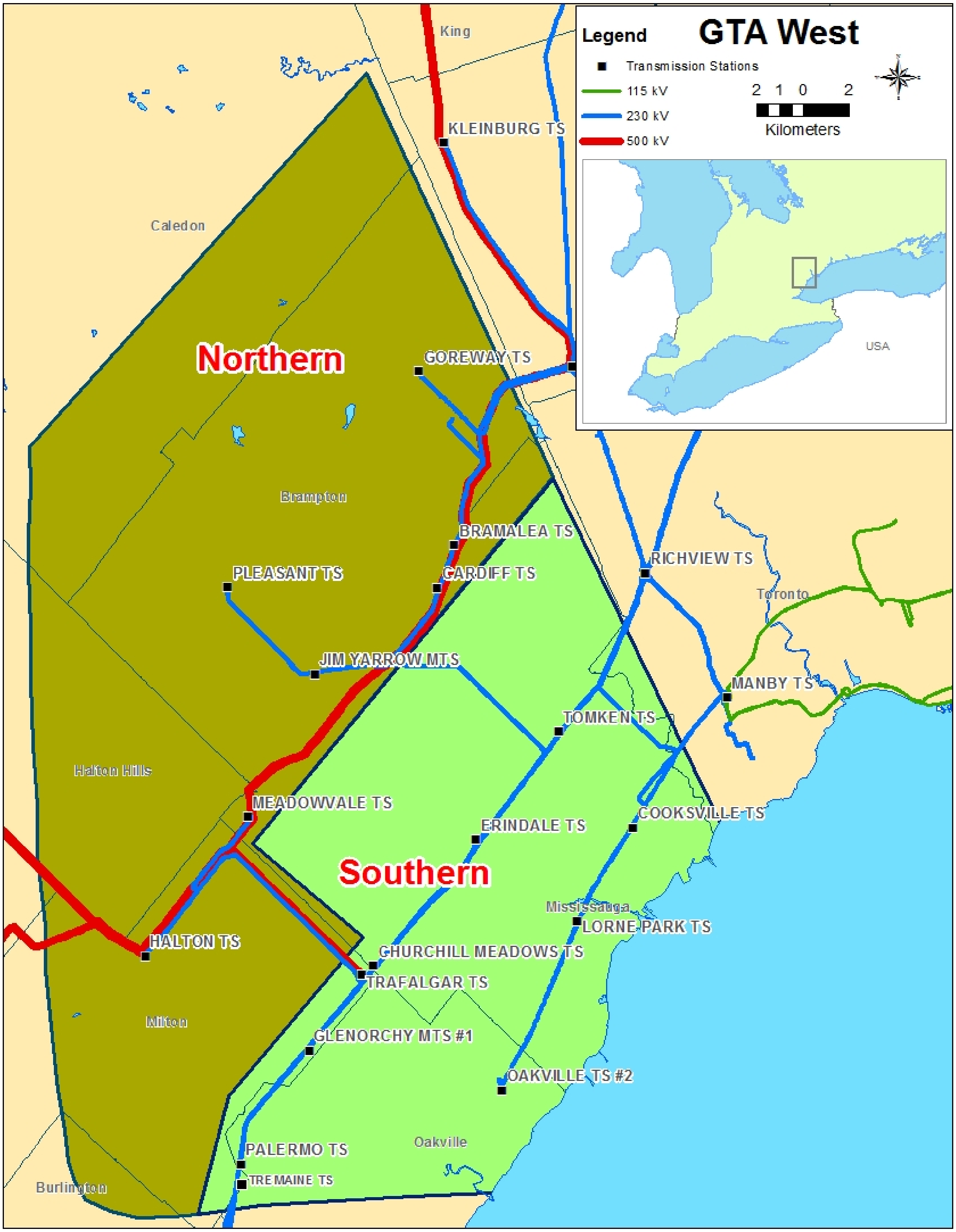

Figure 1-1 GTA West Region Map

1.1 Scope and Objectives

This RIP report examines the needs in the GTA West Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop wires plans to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period and wires plans to address these needs based on new and/or updated information;
- Develop a plan to address any longer terms needs identified by the Working Group.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process;
- Section 3 describes the region;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast and study assumptions used in this assessment;
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs;
- Section 7 discusses the needs and provides the alternatives and preferred solutions;
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] also referred to as Needs Screening

a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee (LAC) in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

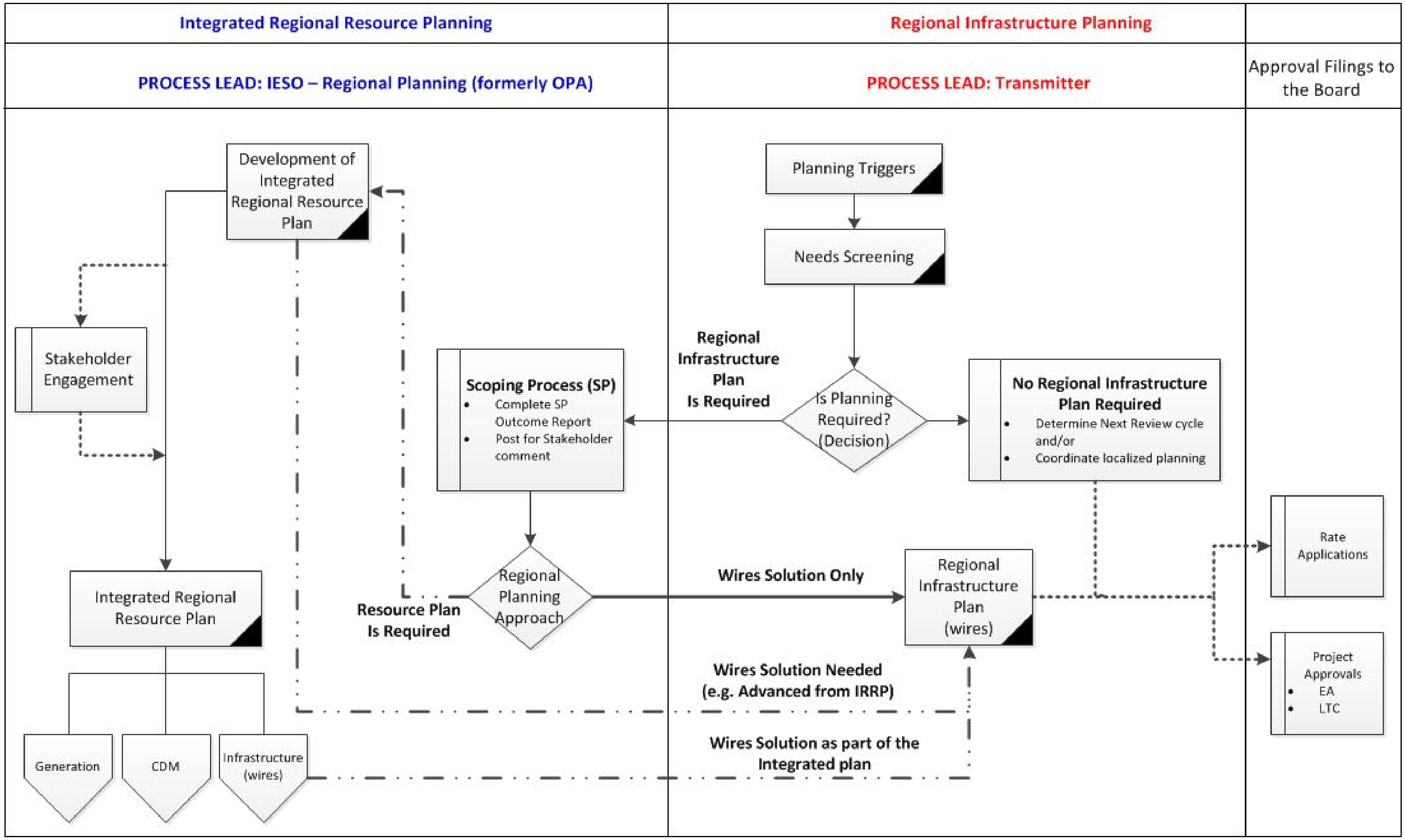

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions, load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

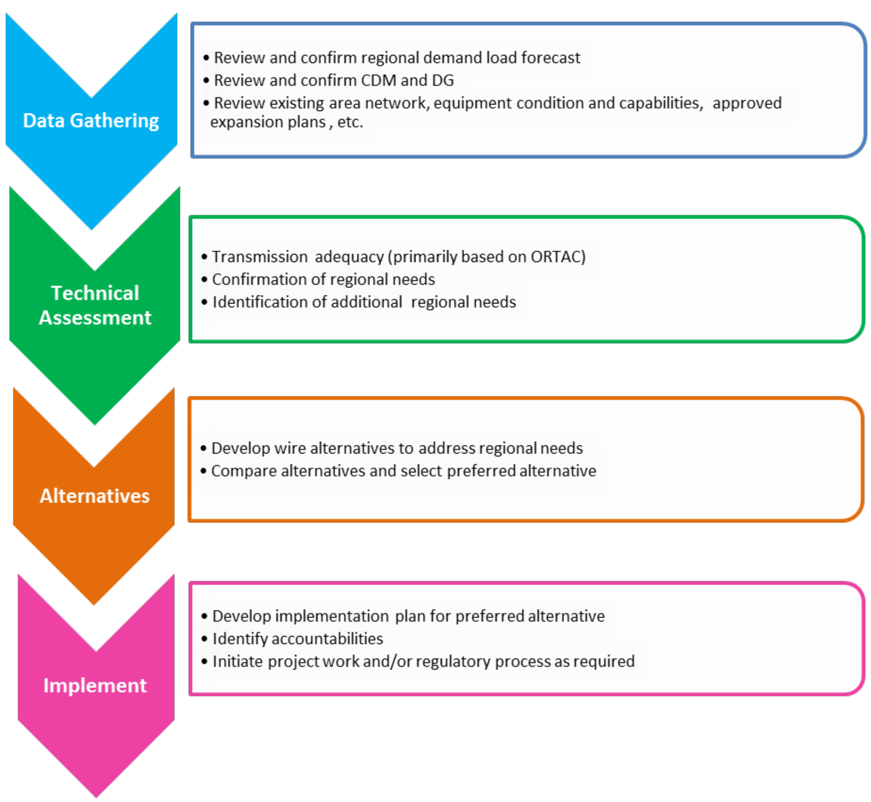

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA WEST REGION ENCOMPASSES THE MUNICIPALITIES OF BRAMPTON, SOUTHERN CALEDON, HALTON HILLS, MISSISSAUGA, MILTON, AND OAKVILLE. THE REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY HIGHWAY 27 TO THE NORTH-EAST, HIGHWAY 427 TO THE SOUTH-EAST, REGIONAL ROAD 25 TO THE WEST, KING STREET TO THE NORTH AND LAKE ONTARIO TO THE SOUTH.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and 500/230 kV autotransformers at Trafalgar TS, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. Local generation in the region includes the two gas fired plants: Sithe Goreway CGS (839 MW rated capacity) and TCE Halton Hills CGS (683 MW rated capacity). The summer 2015 regional coincidental peak load of the region is approximately 2900 MW.

LDCs supplied from electrical facilities in the GTA West Region are Burlington Hydro Electric Inc., Enersource Hydro Mississauga Inc., Halton Hills Hydro Inc., Hydro One Brampton Networks Inc., Hydro One Networks Inc. (Distribution), Milton Hydro Distribution Inc., and Oakville Hydro Electricity Distribution Inc. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Northwest GTA IRRP report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Northern Sub-Region which included the 230 kV facilities in the northern part of Region. The May 2014 Southern GTA Needs Assessment report, prepared by Hydro One, considered the remainder of the GTA West Region.

For the purpose of regional planning, the GTA West Region is divided into Northern and Southern Sub-Regions. A single line diagram showing the electrical facilities of the GTA West Region, consisting of the two sub-regions, is shown in Figure 3-1. More details regarding transformer stations and transmission lines in the region are provided in Appendix A and B, respectively.

GTA West – Northern Sub-Region

The Northern Sub-Region covers the GTA West Region area north of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Claireville TS and Hurontario SS through seven 230/44 kV or 230/27.6kV step down transformer stations, local generation consist of the Sithe Goreway GS located in Brampton and the TransCanada Halton Hills GS located in Halton Hills, Generation is also connected to the LV buses of Bramalea TS in Brampton.

Enersource, Hydro One Brampton, Milton Hydro and Halton Hills Hydro are the three main Local Distribution Companies in the Sub-Region. They receive power at the step down transformer stations and distribute it to the end use customers.

The GTA West – Northern Sub-Region was identified as a "transitional" sub-region, as planning activities in this sub-region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. The Northwest GTA IRRP was completed for the Northern Sub-Region in April 2015.

GTA West – Southern Sub-Region

The Southern Sub-Region covers the GTA West Region area south of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Richview TS and Manby TS. There are a total of nine steps down 230/44 kV or 230/27.6 kV step down transformer stations serving the area customers.

Enersource Hydro Mississauga and Oakville Hydro are the main LDCs serving the GTA West - Southern Sub-Region. There is one large industrial customer (Ford Motor Company) in Oakville.

The NA and SA for the Southern Sub-Region were completed in May and September 2014, respectively. A Local Plan has also been developed in this sub-region to address a near-term station capacity need at Erindale TS, further discussed in Section 7.2.

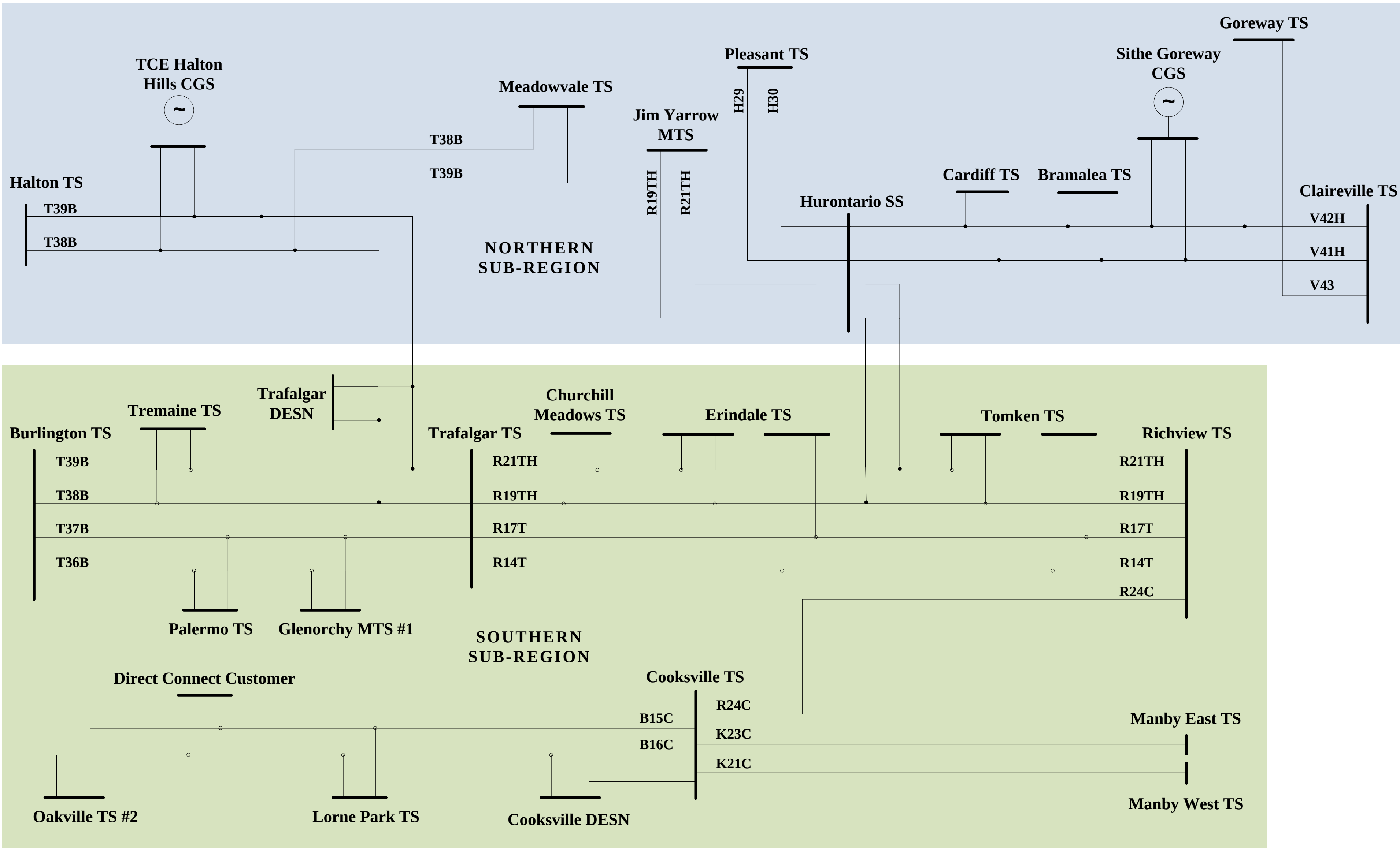

Figure 3-1 GTA West Region Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED AND/OR UNDERWAY IN THE LAST TEN YEARS

IN THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE GTA WEST REGION.

A brief listing of those projects is given below:

- Cardiff TS (2005) – built a new step down transformer station consisting of two 50/83 MVA transformers in Brampton supplied from 230 kV circuits V41H and V42H. This station provided additional load meeting capability to meet Enersource Hydro Mississauga Inc. requirements.
- Sithe Goreway CGS (2008) – connect a new 839 MW gas-fired combined cycle generation station in Brampton connected to 230 kV circuits V41H and V42H. This generation station provided necessary local power to supply the GTA West Region.
- Halton TS Shunt Capacitor - installed 43.2 MX of shunt capacitor banks at Halton TS 27.6 kV bus for voltage support (2009).
- Churchill Meadows TS (2010) – built a new step down transformer station consisting of two 75/125 MVA transformers in Mississauga supplied from 230 kV circuits R19TH and R21TH. This station provided additional load meeting capability to meet Enersource Hydro Mississauga Inc. requirements.
- Hurontario SS and underground cable work - built a new switching station Hurontario SS, 4.2 km of double circuit 230 kV Line from Hurontario SS to Cardiff TS and 3.3 km of underground cable from Hurontario SS to Jim Yarrow TS (2010). The new switching station and associated line work connects the R19T/R21T circuits and the V42/V43H circuits to provide relief and improved reliability to Pleasant TS and Jim Yarrow MTS.
- Halton Hills CGS (2010) – connected a new 683 MW gas-fired combined cycle generation station in Halton Hills connected to 230 kV circuits T38B and T39B. This generation station provided necessary local power to supply the GTA West Region.
- Glenorchy MTS (2011) – connected new Oakville Hydro-owned Glenorchy MTS to 230 kV circuits T36B and T37B. This station provided additional load meeting capability to meet Oakville Hydro requirements
- Tremaine TS (2012) – built a new step down transformer station consisting of two 75/125 MVA transformers in Burlington supplied from 230 kV circuits T38B and T39B. This station provided additional load meeting capability to meet Burlington Hydro and Milton Hydro requirements.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA West Region is expected to grow at an average rate of approximately 0.8% annually from 2015 to 2025, and 0.5% from 2025 to 2035. The growth rate varies across the region ranging from 1.1% in the Northern Sub Region to 0.5% in the Southern Sub Region over the first 10 years. Longer term is a more uniform growth rate of 0.5% across both Northern and Southern Sub Regions. .

Figure 5-1 shows the GTA West Region load forecast from 2016 to 2035. The forecast shown is the regional coincidental forecast, representing the sum of the load in the area for the 17 step-down transformer stations at the time of the regional peak, and is used to determine any need for additional transmission reinforcements. The coincidental regional peak is forecast to increase from approximately 2900 MW in 2015 to 3300 MW in 2035. Non-coincident forecast for the individual stations in the region is available in Appendix A, and is used to determine any need for station capacity relief.

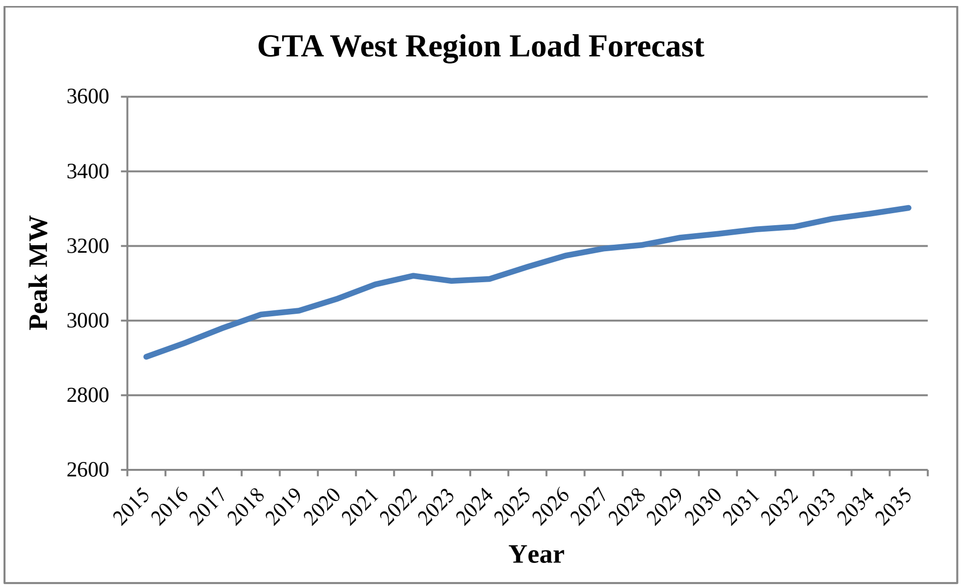

Figure 5-1 GTA West Region Extreme Weather Peak Load Forecast

The regional coincidental load forecast was developed by projecting the 2015 summer peak loads corrected for extreme weather, using the area station growth rates as per the 2015 IESO Northwest GTA IRRP and as per the 2014 Hydro One's Need Assessment Study for the GTA West Southern Sub-Region. The growth rate accounts for CDM measures and connected DG. Details on CDM and connected DG information used in this report are provided in the Northwest GTA IRRP and the Southern Sub-Region's NA, and not repeated in this report.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2015-2035.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STATION FACILITIES SUPPLYING THE GTA WEST REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE 2016-2025 PERIOD.

Within the current regional planning cycle, three regional assessments have been conducted for the GTA West Region. The findings of these assessments are input to the RIP. These assessments are:

1) The Northwest GTA Integrated Regional Resource Plan (IRRP), April 2015 [1]
2) The GTA West Southern Sub-Region's Needs Assessment (NA) Report, May 2014 [2]
3) The GTA West Southern Sub-Region's Scoping Assessment (SA) Report, September 2014 [3]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demand over the 2016-2025 period. These regional needs are summarized in Table 6-1. Table 6-1 also includes the longer-term needs (up to 2035) that have been identified in the Northern Sub-Region. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the GTA West Region was also carried out as part of the RIP report. Sections 6.1 to 6.3 present the results of this review.

Table 6-1 Needs Identified in Previous Phases of the GTA West Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	Halton TS	2018-2020
	7.2	Erindale TS (T1/T2)	Today
Transmission Circuit Capacity	7.3	Richview x Trafalgar (R14T/R17T & R19TH/R21TH)	Within 5 years
	7.4	Radial Supply to Pleasant TS (H29/H30)	2023-2026
	7.5	Radial Supply to Halton TS (T38B/T39B)	2029+
Supply Security	7.6	Supply Security to Halton Radial Pocket (T38B/T39B)	2027
Supply Restoration	7.7	Supply Restoration in Northern Sub-Region (1): - Halton Radial Pocket (T38B/T39B) - Pleasant Radial Pocket (H29/H30) - Cardiff/Bramalea Supply (V41H/V42H)	Today
	7.8	Supply Restoration in Southern Sub-Region: - West of Cooksville (B15C/B16C) - Richview x Trafalgar x Hurontario (R19TH/R21TH) - Richview x Trafalgar (R14T, R17T)	Today
Long-Term Growth	7.9	Pleasant TS (T1/T2) NWGTA Electricity Corridor	2026-2033+

(1) The Northwest GTA IRRP also identified an issue and need to assess "Kleinburg Radial Pocket" supply restoration. This need is being assessed as part of the IESO led Bulk System Study and is not part of this RIP.

6.1 230 kV Transmission Facilities

All 230 kV transmission facilities in the GTA West Region, with the exception of Hurontario SS to Pleasant TS 230 kV circuits H29 and H30 are classified as part of the Bulk Electricity System (BES). A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-1):

1. Claireville TS to Hurontario SS (230 kV Circuits V41H, V42H, V43) – Supply Bramalea TS, Cardiff TS, and Goreway TS
2. Hurontario SS to Pleasant TS (230 kV Circuits H29, H30) – Supply Pleasant TS
3. Trafalgar TS to Burlington TS, radial tap to Halton TS and Meadowvale TS (230 kV Circuits T38B, T39B) – Supply Halton TS, Meadowvale TS, and Trafalgar DESN
4. Trafalgar TS to Burlington TS (230 kV Circuits T36B, T37B, T38B, T39B) – Supply Glenorchy MTS #1, Palermo TS, and Tremaine TS
5. Richview TS to Trafalgar TS (230 kV Circuits R14T, R17T) – Supply Erindale TS and Tomken TS
6. Richview TS to Trafalgar TS, with tap to Hurontario SS (230 kV Circuits R19TH, R21TH) – Supply Churchill Meadows TS, Erindale TS, Jim Yarrow MTS, and Tomken TS
7. Richview TS and Manby TS to Cooksville TS (230 kV Circuits R24C, K21C, K23C, B15C, B16C) – Supply Cooksville DESN, Ford Oakville CTS, Lorne Park TS, and Oakville TS #2

Based on current forecast station loadings and bulk transfers, the H29/H30 circuits will require reinforcement by 2023-2026. The H29/H30 upgrade will be addressed by Hydro One based on the recommendation stemming from the Northwest GTA IRRP led by the IESO. The Trafalgar to Richview 230 kV circuits (R14T/R17T) will require reinforcement in the near term based on GTA West Southern Sub-Region's NA. This need will be further assessed in the IESO led Bulk System Study.

6.2 500/230 kV Transformation Facilities

All loads are supplied from the 230 kV transmissions system. The primary source of 230 kV supply is the 500/230 kV autotransformers at Trafalgar TS and Claireville TS, as well as 230 kV supply from Burlington TS. Additional support is provided from the 230 kV generation facilities at Halton Hills CGS and Sithe Goreway CGS. Based on the long term forecast in the Northwest GTA IRRP, Trafalgar TS and Claireville TS may require relief in the next 10 years. This need will be studied under the IESO led Bulk System Study.

6.3 Step-Down Transformation Facilities

There are a total of sixteen step-down transformer stations in the GTA West Region. Based on the local station load forecast, Halton TS and Erindale TS would require station capacity relief in the near term, as shown in Table 6-2.

Table 6-2 Step-Down Transformer Stations Requiring Relief

Station	Capacity (MW)	2015 Loading (MW)	Need Date
Halton TS	185.9	176.4	2018
Erindale TS (T1/T2)	181.3	208.3	Now
Pleasant TS (T1/T2)	148.1	124.8	2026-2033 (1)

(1) 2026 under the "Higher Growth" scenario, while 2033 under the "Expected Growth" scenario. Please refer to Northwest GTA IRRP [1]

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES OPTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE GTA WEST REGION. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE NORTHWEST GTA IRRP AND THE NA FOR THE GTA WEST SOUTHERN SUB-REGION AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 Halton TS Station Capacity

7.1.1 Description

Halton TS supplies Halton Hills Hydro through 3 feeders and Milton Hydro through 9 feeders at the station. As the load in Halton Hills and Milton continues to grow, the peak load at Halton TS is expected to exceed the station peak load by 2018.

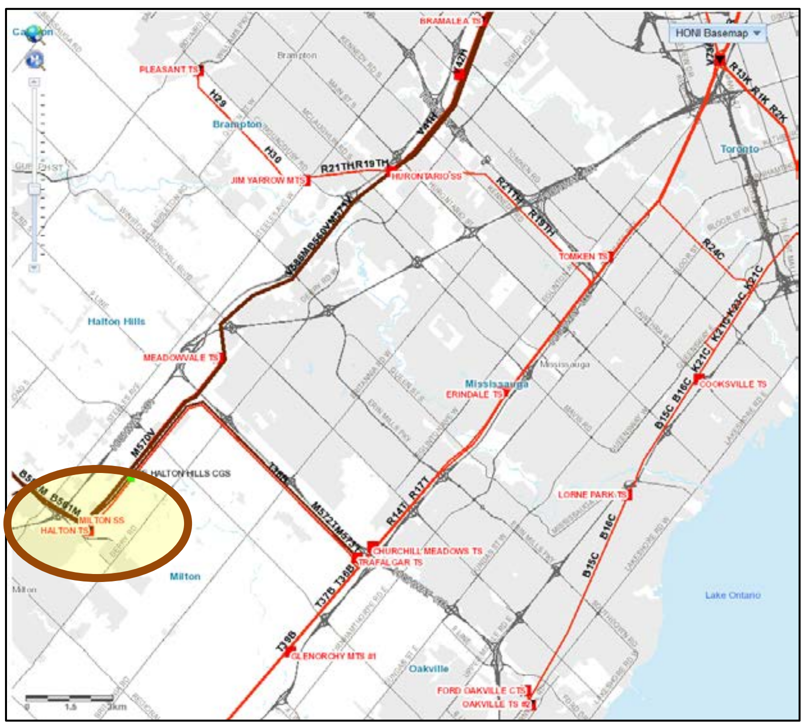

Figure 7-1 Halton TS and Surrounding Areas

7.1.2 Recommended Plan and Current Status

The recommendation of the IRRP is to build two new step-down stations: one to provide supply for Halton Hills Hydro loads and second to supply Milton Hydro load. The Halton Hills Hydro station is expected to be required in 2018, while the Milton Hydro station is expected to be required in 2020.

The IRRP recommends that Halton Hills Hydro proceed to gain the necessary approvals to construct, own, and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018. Halton Hills Hydro has started a Request for Proposal for the work to construct Halton Hills MTS. The station will consists of two 50/83 MVA transformers with capacity to connect eight distribution feeders. The existing Halton Hills CGS will be expanded to accommodate the HV connection of Halton Hills MTS. There are no transmitter costs for this station. The expected in-service date is spring of 2018. The cost for this station is estimated to be $19 million.

The IRRP recommends Hydro One to initiate engineering work for the development of Halton TS #2 in 2017 (3 year lead-time), at the site of the existing Halton TS, with a tentative in-service date of 2020. The Halton Hills TS #2 will consist of two 75/125 MVA transformers with capacity to connect eight distribution feeders. It will tap to circuits T38B and T39B. The cost for Hydro One to build Halton TS #2 is estimated to be $29 million.

7.2 Erindale TS (T1/T2) Station Capacity

7.2.1 Description

Erindale TS solely supplies Enersource Hydro Mississauga Inc. The existing Erindale TS (T1/T2) DESN load currently exceeds the normal supply capacity. However, there is extra capacity available in the area's 44 kV system that can be utilized by building a step down (44/27.6 kV) distribution station.

Options for providing the required relief were investigated in Local Planning for Erindale TS T1/T2 DESN Capacity Relief [4]. As per the Local Plan, Hydro One and Enersource agreed that this is primarily a distribution planning issue that will involve planning and building a new DS by Enersource to utilize the extra 44 kV station capacity in the area.

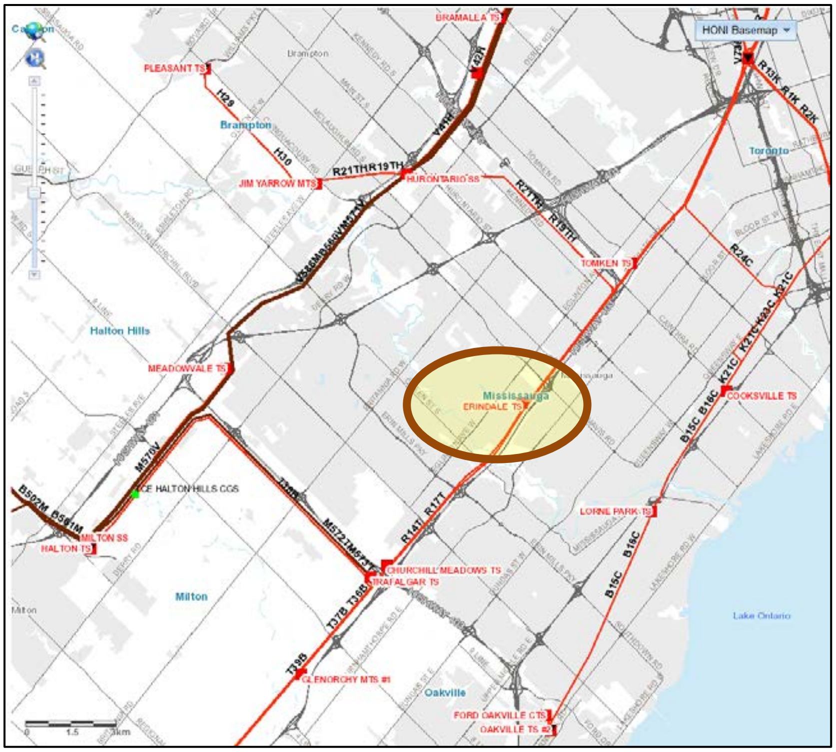

Figure 7-2 Erindale TS and Surrounding Areas

7.2.2 Recommended Plan and Current Status

The proposed DS ("Mini-Britannia MS") is planned to be supplied from Churchill Meadows TS (44 kV system) and provide additional capacity to feed the 27.6 kV load currently supplied by Erindale TS T1/T2. This configuration will reduce over-capacity loading at Erindale TS T1/T2 while balancing the loading capability on 44 kV system via Churchill Meadows TS.

At completion, the substation will house two power transformers (40 MVA capacity), two high voltage switchgears and two low voltage switchgears that will deliver power via four 27.6 kV feeders.

This option is expected to cost $5 million. Under this option, Enersource will build the new DS, own it and recover the costs through the distribution rates. The expected in-service date for the DS is 2018-2019.

7.3 Richview x Trafalgar Transmission Circuit Capacity

7.3.1 Description

As identified in the GTA West Southern Sub-Region's NA, with a single-circuit contingency and high Flow East Towards Toronto (FETT) interface flows, loading on the Richview TS to Trafalgar TS circuits (R14T, R17T, R19TH, R21TH) exceeded their summer long-term emergency ratings in the near-term.

7.3.2 Recommended Plan and Current Status

As these circuits are part of the Bulk Electric System, this need is being further assessed in the IESO-led bulk power system planning.

7.4 Radial Supply to Pleasant TS Transmission Circuit Capacity

7.4.1 Description

Pleasant TS consists of 3 DESNs supplied by 230 kV H29/H30 circuits. Due to growth in load forecasted at Pleasant TS, these circuits are expected to reach their thermal capacity by 2023 at the earliest.

The IRRP process, completed in April 2015, identified the need, discussed alternatives, and recommended a solution to resolve this need.

7.4.2 Recommended Plan and Current Status

The existing conductors used for 230kV circuits H29/H30 going to Pleasant TS are 795.0 kcmil ACSR 26/7 with summer long term emergency rating of 1090 A (at 127°C). They extend 8.5km north from Hurontario SS to Pleasant TS. Based on the study conducted in the Northwest GTA IRRP, this rating limits the maximum load-carrying capacity to approximately 417 MW of load at Pleasant TS.

Preliminary feasibility study shows that the existing towers can support larger conductors. The recommended new conductors would be 1192.5 kcmil ACSR 54/19 with summer long term emergency rating of approximately 1400 A (at 127°C). As per the load flow study conducted in the IRRP, this would supply over 500 MW of load at Pleasant TS. The estimated budgetary cost of this upgrade is about $6.5 million.

The Working Group recommends regularly monitoring the actual load growth and reassessing this issue during the next regional planning cycle.

7.5 Radial Supply to Halton TS Transmission Circuit Capacity

7.5.1 Description

The Northwest GTA IRRP study identified that the thermal capacity of supply circuit to Halton TS from Trafalgar TS to Burlington TS (T38B/T39B) may be exceeded with a single-circuit contingency and Halton Hills GS out of service in the mid-term. However, under this scenario, the ORTAC permits up to 150 MW of load shedding to prevent system overloads. With this control action in place, this need is observed in the long-term in 2029 at the earliest.

7.5.2 Recommended Plan and Current Status

As per the IRRP recommendation, this regional need is being further assessed in the IESO-led bulk power system planning.

7.6 Supply Security to Halton Radial Pocket (T38B/T39B)

7.6.1 Description

As the load connected to T38B/T39B continues to grow, it is expected by 2027 the Halton Radial Pocket will not be able to meet the ORTAC supply security criteria, which states that no more than 600 MW can be interrupted due to a loss of two major power system elements, as shown in Table 7-1.

Table 7-1 Halton Radial Pocket Load Forecast

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Halton Radial Pocket Load (MW)	463	471	482	490	491	492	503	512	562	571	585	598	**609**

7.6.2 Recommended Plan and Current Status

The Working Group recommends that the bulk power system study led by IESO account for this supply security issue on T38B/T39B in their planning process.

7.7 Supply Restoration in Northern Sub-Region

The Northwest GTA IRRP study identified that the following circuits are currently at risk of not meeting the supply security and restoration criteria:

Table 7-2 Supply Restoration Need in Northern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)
Halton Radial Pocket • Tremaine • Trafalgar DESN • Meadowvale • Halton • Halton Hills Hydro MTS (1) • Halton #2 (1) Supply: T38B/T39B	463	146	**67**
Pleasant Radial Pocket • Pleasant DESNs Supply: H29/H30	359	52	**57**
Bramalea/Cardiff Supply • Bramalea DESNs • Cardiff Supply: V41H/V42H	456	140	**66**

(1) Available 30-min restoration through emergency distribution load transfer following the loss of transmission supply (based on IRRP)
(2) Calculated as follows: Actual Load minus 250 MW minus 30minRestorationCapability. 250 MW is the maximum amount of load not restored within 30-min following loss of two elements.
(3) Halton Hills Hydro MTS and Halton TS #2 are expected to be in-service in 2018 and 2020.

The Northwest GTA IRRP also identified "Kleinburg Radial Pocket" supply restoration need. However, this need will be discussed in more details in the IESO's Bulk System Studies.

As per the IRRP recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

It is expected that with new increased forecasted load at Tremaine TS provided by Milton Hydro and Burlington Hydro, circuitsT38B/T39B Burlington TS to Trafalgar TS will experience higher power flow, and the need date may be moved closer. Therefore, the Working Group recommends that the bulk power system study led by IESO account for this increased flow on T38B/T39B in their planning process.

7.8 Supply Restoration in Southern Sub-Region

The GTA West Southern Sub-Region SA identified that the following circuits are at a risk of not meeting the supply security and restoration criteria in the medium term to long term time frame:

Table 7-3 Supply Restoration Need in Southern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)	Load (MW) That Can Be Restored Within 4-hour (1)	4-hour Restoration Shortfall (MW) (3)
West of Cooksville • Oakville #2 • Ford Oakville • Lorne Park Supply: B15C/B16C	304	46	**8**	110	**44**
Richview x Trafalgar x Hurontario • Churchill Meadows • Erindale T5/T6 • Tomken T3/T4 • Jim Yarrow Supply: R19TH/R21TH	555	165	**140**	465	None
Richview x Trafalgar • Erindale T1/T2 • Erindale T3/T4 • Tomken T1/T2 Supply: R14T/R17T	498	115	**133**	390	None

As per the Southern Sub-Region's SA recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

7.9 Long-Term Growth & NWGTA Electricity Corridor Need

Growth projections in the Ontario Governments - Growth Plan for the Greater Golden Horseshoe [5] indicates that the population in Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow significantly over the 20 years period, from 930,000 people in 2011 to 1.5 million people in 2031. Growth plan of this magnitude translates to an overall electrical demand of approximately 849 to 1132 MW by 2031 [1]. Supply electrical demand related to this growth will require new transmission and distribution infrastructure in the area because current electricity infrastructure in the area is limited and at its capacity. Planning and Environmental Approval for a proposed new 400 series Highway, extending from Highway 400 to the Highway 401/407 ETR interchange, has been paused by the Ministry of Transportation. However, opportunities for multi-use transportation/ electricity transmission line corridor must be investigated as new transportation and electricity plans for the area are developed, to maintain consistency with direction outlined in the Provincial Policy Statement.

Existing electricity supply to new developments in the area is technically limited by transmission line and transformer station supply capacity. In addition, there are customer service quality concerns, such as reliability performance and low voltage levels on the LDC's distribution feeders due to the long distance between the locations of new development and existing transformer stations.

Based on the latest load forecast, electrical load at Pleasant TS, which supplies Brampton, is anticipated to exceed its station capacity as early as 2026 [1]. As the result, new station will be required to meet growing electrical needs.

Since a typical 75/125 MVA 230 kV step-down transformer station is capable of supplying up to 170 MW of load, up to 6 new stations in strategic locations could be required to effectively meet load growth in the area over the next 10-20 years. In order to provide adequate supply to these new step-down stations, new 230 kV transmission lines will be required within the general vicinity of the area's load growth centers.

In addition to the need for supply capacity to meet growth, several locations are at risk for not meeting ORTAC criteria following the loss of two transmission elements: Halton radial pocket, Pleasant radial pocket, Bramalea/Cardiff supply, and Kleinburg radial pocket. These needs should also be studied and addressed in a coordinated manner to develop optimal solutions for both GTA North and GTA West Region. As a result, a high degree of integration will be required between regional planning in the two adjacent regions going forward.

Siting a new transmission corridor in the area would provide an alternate supply route to enable continued electrical service when other lines are out of service. Currently it is estimated that over 250 MW of load will not be restored within the timelines prescribed by the criteria. The situation and risk will continue to worsen with continued growth and load will be at higher risk of prolonged power outages following major system contingencies.

An important first phase for providing the required transmission capacity is to identify land / right of ways, which can accommodate economical overhead transmission lines. This includes completing an Environmental Approval followed with an application to the OEB for Leave to Construct (Section 92). The EA process and acquisition of land rights process may take up to five years. Allowing the area to develop without identifying the electricity corridor in municipal plans and not acquiring land rights for transmission corridor now would be significantly arduous after municipal and community development has already taken place without consideration of electricity needs. Identifying and preserving rights-of-way ahead of the forecasted need will help rate payers and municipalities avoid cost associated with underground cables in the future, which is significantly more costly ranging from 5 to 10 times higher than overhead lines.

Continued load growth throughout the GTA, and changing generation patterns across the province, are expected to stress the bulk transmission system's capacity. One option for addressing this need is the addition of a major new 500/230 kV supply point at the existing Milton SS. This new 500/230 kV supply point will provide an additional source to the local network and would need to be supplemented with the incorporation of new 230 kV lines and reconfiguration of the 230 kV system in the area. A new corridor providing new 230 kV transmission lines connecting Milton TS in GTA West and Kleinburg TS in GTA North will allow for better overall bulk system performance in the long-term.

Existing projections of electricity corridor needs can be as early as 2025. The RIP concludes that based on growth projections outlined in the Growth Plan for the Greater Golden Horseshoe [5] a new electricity corridor will be ultimately required to provide additional transmission capacity to meet load growth; provide alternate supply route to various locations to meet restoration criteria; and improve bulk electricity transfer capability.

The RIP Working Group recommends that:

a) The required transmission corridor be identified within the appropriate Regional and Municipal Official Planning documents.

b) Hydro One, the IESO and LDCs undertake immediate action to further assess the location and pace of growth, as well as the related high voltage electrical facilities required for inclusion in a future electricity infrastructure plan. The plan should include but not limited to details with respect to conceptual layout of transmission lines, line terminations, switching stations and the number and approximate location of step-down transformer stations.

c) Following this, Environmental Approval and acquisition of land rights should be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

d) Hydro One, the IESO and LDCs should complete the assessment, technical details, layout of high voltage electricity infrastructure no later than Q4 2016.

8. CONCLUSIONS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA WEST REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Halton TS station capacity
II	Erindale TS T1/T2 station capacity
III	Radial supply to Pleasant TS (H29/H30) circuit capacity
IV	Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity
V	Radial supply to Halton TS (T38B/T39B) circuit capacity
VI	• Supply security to Halton Radial Pocket • Supply restoration to Halton Radial Pocket, Pleasant Radial Pocket, and Bramalea/Cardiff Supply load pockets • Supply restoration to West of Cooksville, Richview x Trafalgar, and Richview x Trafalgar x Hurontario load pockets
VII	Long term need for a new NWGTA electricity transmission corridor

Next steps, lead responsibility, and timeframes for implementing the wires solutions are summarized in the Table 8-2 below. Investments to address the long-term need where there is time to make a decision (Need III) will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans - Next Steps, Lead Responsibility and Plan In-Service Dates

Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
Build new Halton Hills Hydro MTS	LDC to carry out the work	Halton Hills Hydro	2018	$19M (1)	I
Build new Halton TS #2	Transmitter to carry out the work	Hydro One	2020	$29M (1)	I
Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	LDC to carry out the work	Enersource	2018-2019	$5M	II
Upgrade (reconductor) circuits H29/H30 (2)	Transmitter to carry out the work, and monitor growth	Hydro One	2023-2026	$6.5M	III
• R14T/R17T & R19TH/R21TH circuit capacity need • T38/T39B circuit capacity need • Supply security and restoration need	IESO to carry out Bulk System Study	IESO	TBD	TBD	IV, V, VI
Need for a new transmission corridor in NWGTA	Working Group to complete assessments, technical details & layout by Q4 2016	Hydro One, IESO, LDCs	TBD	TBD	VII

Notes:

(1) Excludes cost for distribution infrastructures
(2) The plan will be reviewed and finalized in the next regional planning cycle

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier to address the need.

9. REFERENCES

[1] Independent Electricity System Operator. "Northwest GTA Integrated Regional Resource Plan". April 28, 2015. http://www.ieso.ca/Documents/Regional-Planning/GTA_West/2015-Northwest-GTA-IRRP-Report.pdf

[2] GTA West Southern Sub-Region Study Team. "Needs Screening Report – GTA West Southern Sub-Region". May 30, 2014. http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Needs%20Assessment%20Report%20-%20GTA%20West%20-%20Southern%20Subregion.pdf

[3] GTA West Southern Sub-Region Study Team. "GTA West Southern Sub-Region Scoping Assessment Outcome Report". September 19, 2014. http://www.ieso.ca/Documents/Regional-Planning/GTA_West/Scoping-Assessment-Outcome-Report-September-2014.pdf

[4] Hydro One Networks Inc., Enersource Hydro Mississauga Inc. "Local Planning Report – Erindale TS T1/T2 DESN Capacity Relief – GTA West Southern Sub-Region". July 9, 2015. http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Local%20Planning%20Report%20-%20Erindale%20TS%20Capacity%20-%209_July_2015.pdf

[5] Ministry of Infrastructure. Places to Grow: "Growth Plan for the Greater Golden Horseshoe, 2006". Office Consolidation June 2013. https://placestogrow.ca/content/ggh/2013-06-10-Growth-Plan-for-the-GGH-EN.pdf

Appendix A. Stations in the GTA West Region

Station (DESN)	Voltage (kV)	Supply Circuit
Halton TS	230/27.6	T38B/T39B
Meadowvale TS	230/44	T38B/T39B
Jim Yarrow MTS	230/27.6	R19TH/R21TH
Pleasant TS (T1/T2)	230/44	H29/H30
Pleasant TS (T5/T6)	230/27.6	H29/H30
Pleasant TS (T7/T8)	230/27.6	H29/H30
Cardiff TS	230/27.6	V41H/V42H
Bramalea TS (T1/T2)	230/27.6	V41H/V42H
Bramalea TS (T3/T4)	230/44	V41H/V42H
Bramalea TS (T5/T6)	230/44	V41H/V42H
Goreway TS (T1/T2)	230/27.6	V42H/V43
Goreway TS (T5/T6)	230/27.6	V42H/V43
Goreway TS (T4)	230/44	V42H/V43
Tremaine TS	230/27.6	T38B/T39B
Trafalgar TS	230/27.6	T38B/T39B
Palermo TS	230/27.6	T36B/T37B
Glenorchy MTS #1	230/27.6	T36B/T37B
Churchill Meadows TS	230/44	R19TH/R21TH
Erindale TS (T1/T2)	230/27.6	R14T/R17T
Erindale TS (T3/T4)	230/44	R14T/R17T
Erindale TS (T5/T6)	230/44	R19TH/R21TH
Tomken TS (T1/T2)	230/44	R14T/R17T
Tomken TS (T3/T4)	230/44	R19TH/R21TH
Oakville TS #2	230/27.6	B15C/B16C
Lorne Park TS	230/27.6	B15C/B16C
Cooksville TS (T1/T2)	230/27.6	B16C
Cooksville TS (T3/T4)	230/27.6	B16C

Appendix B. Transmission Lines in the GTA West Region

Location	Circuit Designations	Voltage (kV)
Hurontario SS to Pleasant TS	H29, H30	230
Richview TS to Trafalgar TS	R14T, R17T	230
Richview TS to Trafalgar TS & Hurontario SS	R19TH, R21TH	230
Trafalgar TS to Burlington TS	T36B, T37B, T38B, T39B	230
Claireville TS to Hurontario SS	V41H, V42H	230
Claireville TS to Kleinburg TS (1)	V43	230
Cooksville TS to Oakville TS	B15C, B16C	230
Manby TS to Cooksville TS	K21C, K23C	230
Richview TS to Cooksville TS	R24C	230

(1) Only V43 sections that supplies Goreway TS is included

Appendix C. Distributors in the GTA West Region

Distributor Name	Station Name	Connection Type
Burlington Hydro Inc.	Palermo TS	Tx
	Tremaine TS	Tx
Enersource Hydro Mississauga Inc.	Bramalea TS	Dx
		Tx
	Cardiff TS	Tx
	Churchill Meadows TS	Tx
	Cooksville TS	Tx
	Erindale TS	Tx
	Lorne Park TS	Tx
	Meadowvale TS	Tx
	Oakville TS #2	Dx
	Tomken TS	Tx
Halton Hills Hydro Inc.	Halton TS	Dx
		Tx
	Pleasant TS	Dx
Hydro One Brampton Networks Inc.	Bramalea TS	Tx
	Goreway TS	Tx
	Jim Yarrow MTS	Tx
	Pleasant TS	Tx
Hydro One Networks Inc. (Distribution)	Bramalea TS	Tx
	Halton TS	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Pleasant TS	Tx
	Trafalgar TS	Tx
Milton Hydro Distribution Inc.	Halton TS	Tx
	Palermo TS	Dx
	Tremaine TS	Tx
Oakville Hydro Electricity Distribution Inc.	Glenorchy MTS #1	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Trafalgar TS	Dx

Appendix D. GTA West Stations Load Forecast

GTA West Non-Coincident Stations Load Forecast (MW)

DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bramalea TS T1/T2	N	188.4	124.6	124.7	124.3	124.2	122.0	122.7	122.7	122.5	121.7	119.9	119.2	121.4	121.0	119.7	119.6	118.3	118.2	118.1	119.0	119.3	119.5
Bramalea TS T3/T4	N	105.7	99.5	99.4	99.3	99.0	97.5	97.2	97.0	96.7	96.0	94.8	94.4	94.8	94.2	93.3	93.1	92.3	91.9	91.6	92.1	92.0	91.9
Bramalea TS T5/T6	N	159.1	122.9	123.0	122.7	122.6	120.3	120.9	120.7	120.4	119.4	117.4	116.7	118.2	117.6	116.2	116.0	114.6	114.4	114.3	115.2	115.4	115.6
Cardiff TS T1/T2	N	113.5	108.8	109.1	109.8	110.0	109.4	108.8	109.2	109.4	109.6	109.3	109.6	109.8	109.8	109.6	109.9	110.1	110.0	110.0	111.0	111.3	111.6
Goreway TS T1/T2	N	184.0	35.5	39.7	41.8	44.8	44.5	49.7	52.6	55.0	55.0	54.2	58.9	62.0	63.4	62.5	63.1	62.4	62.0	61.9	63.7	64.1	64.6
Goreway TS T4	N	84.0	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8
Goreway TS T5/T6	N	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2
Halton Hills Hydro MTS	N	97.1	0.0	0.0	0.0	3.5	8.1	11.7	15.8	19.7	23.5	26.9	32.2	37.2	42.1	46.7	51.7	51.9	51.9	52.0	52.9	53.2	53.6
Halton TS T3/T4	N	185.9	176.4	179.1	184.4	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0
Halton TS #2	N	146.3	0.0	0.0	0.0	0.0	0.0	2.3	11.0	18.5	66.2	72.5	80.2	87.2	93.5	99.0	105.9	112.1	118.2	116.9	117.9	120.0	122.1
Jim Yarrow MTS T1/T2	N	156.6	132.3	134.9	136.3	138.3	138.3	142.6	144.6	146.1	146.1	145.2	148.1	149.6	149.8	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Meadowvale TS T1/T2	N	180.8	128.7	127.1	126.0	124.4	121.9	119.4	118.1	116.5	115.0	113.0	111.6	110.1	108.5	106.7	105.4	104.0	102.4	100.9	100.2	99.0	97.8
Pleasant TS T1/T2	N	148.1	124.8	127.5	131.2	134.3	134.3	135.0	136.3	137.6	138.5	138.0	139.9	141.1	141.8	142.0	142.7	143.8	144.7	145.8	148.4	150.0	151.6
Pleasant TS T5/T6	N	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3
Pleasant TS T7/T8	N	187.7	45.1	54.5	56.8	57.9	57.9	63.5	66.7	69.3	70.0	68.0	74.7	77.8	79.4	77.0	77.0	76.7	76.1	75.8	79.0	79.8	80.6

DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Churchill Meadows TS T1/T2	S	172.5	101.6	102.0	102.3	102.2	101.3	100.5	100.5	100.4	100.2	100.0	99.9	99.7	99.5	99.3	99.2	99.0	98.8	98.7	98.5	98.3	98.1
Cooksville TS T3/T4	S	119.8	52.9	52.4	53.3	54.2	54.5	54.8	55.6	56.5	57.5	58.1	58.7	59.3	60.0	60.6	61.2	61.9	62.5	63.2	63.8	64.5	65.2
Cooksville TS T1/T2	S	119.7	49.8	49.4	50.1	51.0	51.3	51.6	52.3	53.2	54.1	54.7	55.2	55.8	56.4	57.0	57.6	58.2	58.8	59.4	60.0	60.6	61.3
Erindale TS T1/T2	S	181.3	208.3	210.2	211.9	212.6	210.9	208.7	208.2	207.4	206.5	206.3	206.1	205.8	205.6	205.4	205.2	205.0	204.8	204.5	204.3	204.1	203.9
Erindale TS T3/T4	S	193.0	150.6	150.9	151.0	150.8	149.4	148.0	148.0	147.8	147.5	147.1	146.7	146.4	146.0	145.6	145.2	144.8	144.5	144.1	143.7	143.4	143.0
Erindale TS T5/T6	S	195.1	171.9	172.2	172.4	172.2	170.6	169.0	169.0	168.8	168.4	168.0	167.5	167.1	166.7	166.3	165.8	165.4	165.0	164.6	164.1	163.7	163.3
Glenorchy MTS #1 T1/T2	S	153.0	50.1	57.5	68.0	80.7	107.4	133.5	152.4	158.9	91.0	94.9	98.9	103.1	107.6	112.2	117.0	122.0	127.2	132.6	138.3	144.2	150.4
Lorne Park TS T1/T2	S	144.6	119.4	118.4	120.4	122.5	123.3	123.9	125.6	127.7	130.0	131.4	132.8	134.2	135.7	137.1	138.6	140.1	141.6	143.1	144.6	146.2	147.8
Oakville TS #2 T5/T6	S	185.2	157.8	157.0	157.7	158.2	157.2	156.1	156.5	156.8	157.2	157.1	157.1	157.0	156.9	156.8	156.8	156.7	156.6	156.5	156.5	156.4	156.3
Palermo TS T3/T4	S	109.5	82.6	84.0	87.1	90.4	89.2	88.1	87.8	87.3	86.8	87.3	87.9	88.5	89.0	89.6	90.2	90.7	91.3	91.9	92.5	93.1	93.7
Tomken TS T1/T2	S	173.3	138.8	140.6	142.0	142.4	141.1	139.7	139.4	138.9	138.3	138.2	138.2	138.1	138.1	138.0	138.0	137.9	137.8	137.8	137.7	137.7	137.6
Tomken TS T3/T4	S	192.8	149.7	151.7	153.2	153.6	152.3	150.7	150.5	149.9	149.3	149.3	149.2	149.2	149.1	149.1	149.0	149.0	148.9	148.9	148.8	148.8	148.8
Trafalgar TS T1/T2	S	124.0	85.1	84.7	84.5	83.9	82.8	81.6	81.2	80.7	80.2	79.6	79.0	78.4	77.9	77.3	76.7	76.1	75.6	75.0	74.5	73.9	73.4
Tremaine TS T1/T2	S	189.5	72.9	79.7	86.8	92.6	91.8	91.1	91.1	90.9	90.7	93.3	96.0	98.7	101.5	104.4	107.4	110.4	113.6	116.8	120.1	123.6	127.1

Notes:

- Northern (N) Sub-Region's stations load forecast is based on the IRRP [1] "Expected Growth" Scenario.
- Southern (S) Sub-Region's stations load forecast is based on the NA [2] non-coincident stations load forecast.
- Halton Hills Hydro MTS and Halton TS #2 are assumed to be in-service in 2018 and 2020, respectively. Some load from Glenorchy MTS will be transferred to the new Halton TS #2 in 2023, as shown by the corresponding increase and decrease at those stations.
- Load forecast were updated for Palermo TS, Tremaine TS, and Glenorchy MTS based on new information provided by Milton Hydro and Burlington Hydro.

Appendix E. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

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Exhibit B-1-1
TSP Section 1.2
Attachment 7
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Kitchener-Waterloo-Cambridge-Guelph

REGIONAL INFRASTRUCTURE PLAN

December 15, 2015

hydro one

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Cambridge and North Dumfries Hydro Inc.
Centre Wellington Hydro
Guelph Hydro Electric System Inc.
Halton Hills Hydro
Hydro One Distribution
Independent Electricity System Operator
Kitchener Wilmot Hydro Inc.
Milton Hydro
Waterloo North Hydro Inc.
Wellington North Power Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE KITCHENER-WATERLOO-CAMBRIDGE-GUELPH ("KWCG") REGION.

The participants of the RIP Working Group included members from the following organizations:

- Cambridge and North Dumfries Hydro Inc.
- Centre Wellington Hydro
- Guelph Hydro Electric System Inc.
- Halton Hills Hydro One
- Hydro One Distribution
- Hydro One Transmission
- Independent Electricity System Operator
- Kitchener Wilmot Hydro Inc.
- Milton Hydro
- Waterloo North Hydro Inc.
- Wellington North Power Inc.

This RIP provides a consolidated summary of needs and recommended plans for the KWCG Region for the near-term (up to 5 years) and mid-term (5 to 10 years). No long term needs (10 to 20 years) have been identified at this time.

This RIP is the final phase of the regional planning process and it follows the completion of the KWCG Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015.

The major infrastructure investments planned for the KWCG Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the table below.

No.	Project	In-Service Date	Cost
1	Guelph Area Transmission Reinforcement	May 2016	$95 M
2	Arlen MTS: Install Series reactors	May 2016	$0.95 M
3	M20D/M21D – Install 230 kV In-line Switches	May 2017	$6 M
4	Waterloo North Hydro: MTS #4	2024	TBD

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle may be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE KWCG REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) and documents the results of the joint study carried out by Hydro One, Kitchener-Wilmot Hydro Inc. (“Kitchener-Wilmot Hydro”), Waterloo North Hydro Inc. (“WNH”), Cambridge & North Dumfries Hydro Inc. (“CND”), Guelph Hydro Electric Systems Inc. (“Guelph Hydro”), Hydro One Distribution and the Independent Electricity System Operator (“IESO”) in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

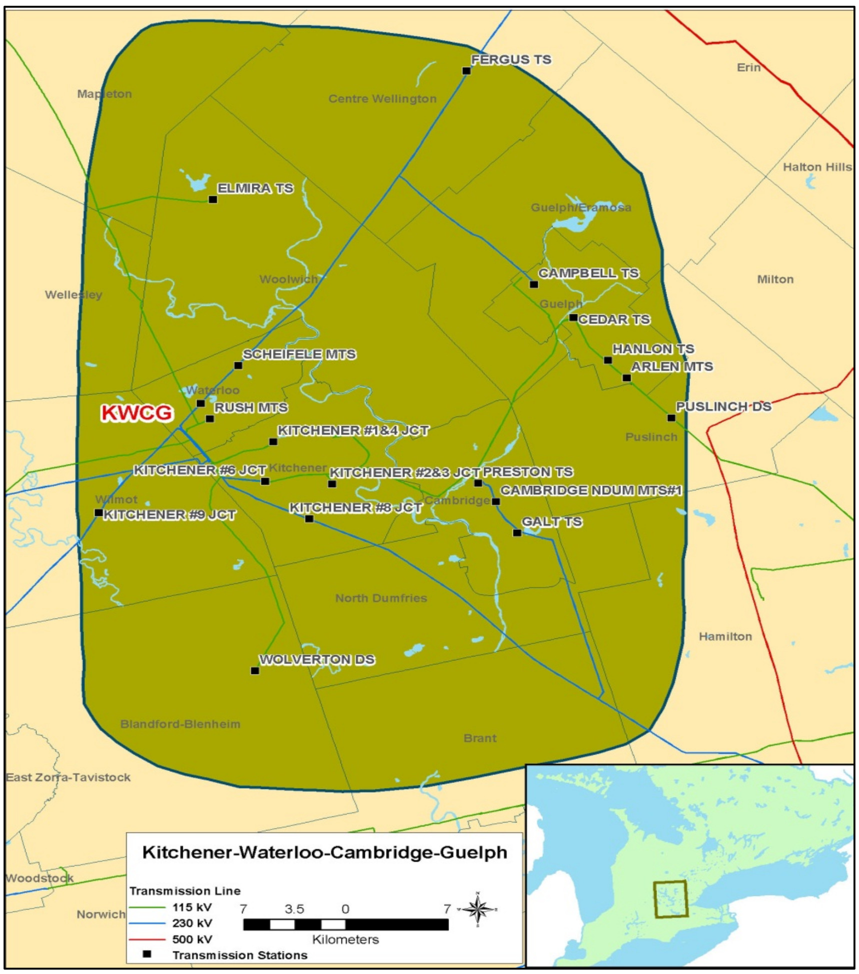


Figure 1-1 KWCG Region

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2015 coincident regional load was about 1240 MW. The boundaries of the Region are shown in Figure 1-1 above.

1.1 Scope and Objectives

This RIP report examines the needs in the KWCG Region. Its objectives are:

- To identify new supply needs that may have emerged since previous planning phases (e.g. Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan)
- To assess and develop a wires plan to address these needs
- To provide the status of wires planning currently underway or completed for specific needs
- To identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as load forecast, transmission and distribution system capabilities along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan)
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated RIP phase information
- Develop a plan to address any longer term needs identified by the Working Group

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

1.2 Structure

The rest of the report is organized as the follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the region
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs
- Section 7 summarizes the Regional Plan to address the needs
- Section 8 provides the conclusions and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013, through amendments to the Transmission System Code ("TSC") and the Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ('SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation ("DG")) options at a higher or more macro level but sufficient to permit a comparison of options. If the IRRP process identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend the preferred wires solution. Similarly, resource options which the IRRP identifies as best

[1] Also referred to a Needs Screening

suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timeliness provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect
- The NA, SA, and LP phases of regional planning
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region

Figure 2-1 illustrates the various steps of the regional planning process (NA, SA, IRRP and RIP) and their respective phase trigger, lead, and outcome.

Note that as the KWCG Region was identified as a "transitional" region at the onset of the OEB defined Regional Planning process in 2013, the Needs Assessment and Scoping Assessment phases were deemed complete and the region was placed into the IRRP phase of the process.

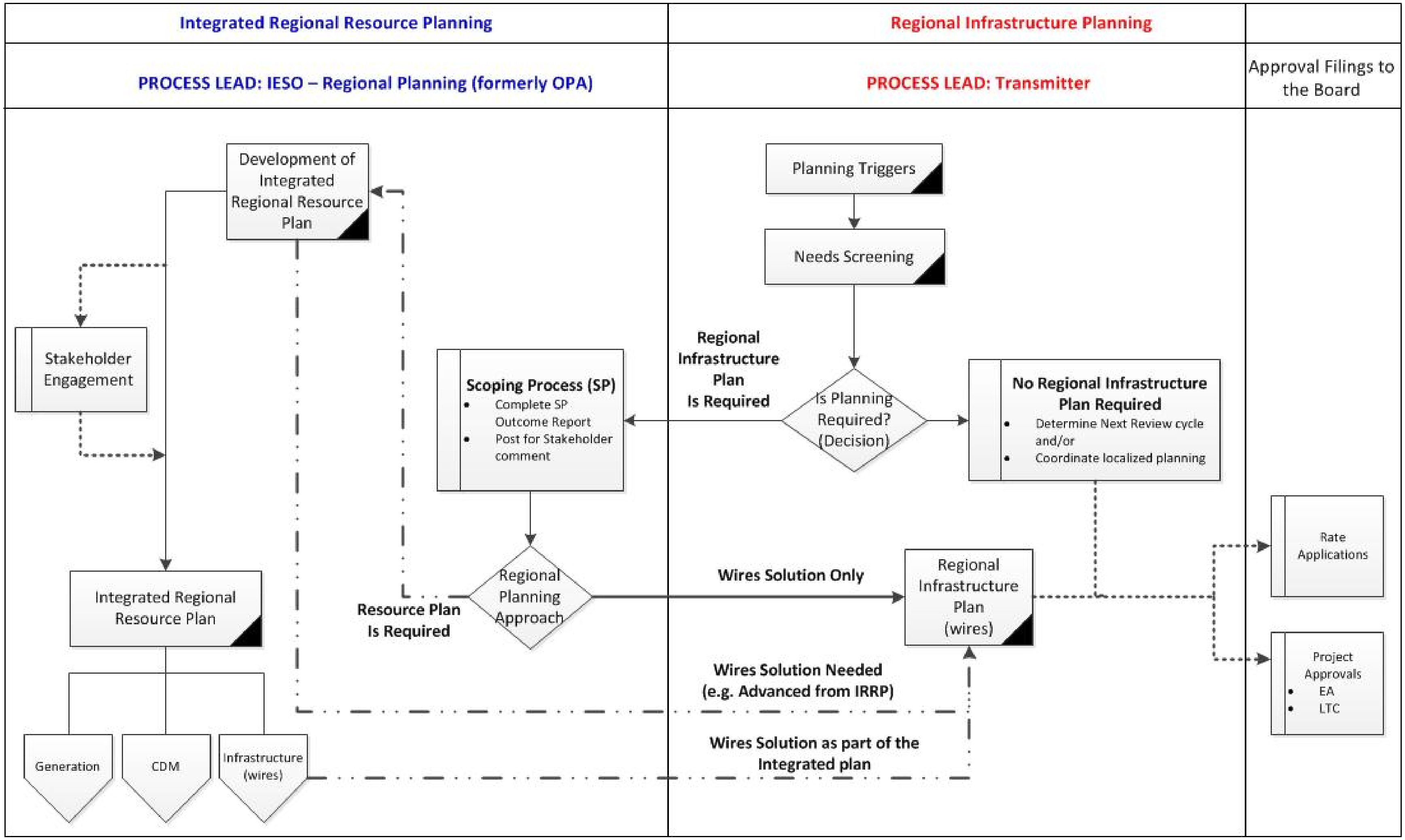


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1) Data Gathering: The first step of the RIP phase is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

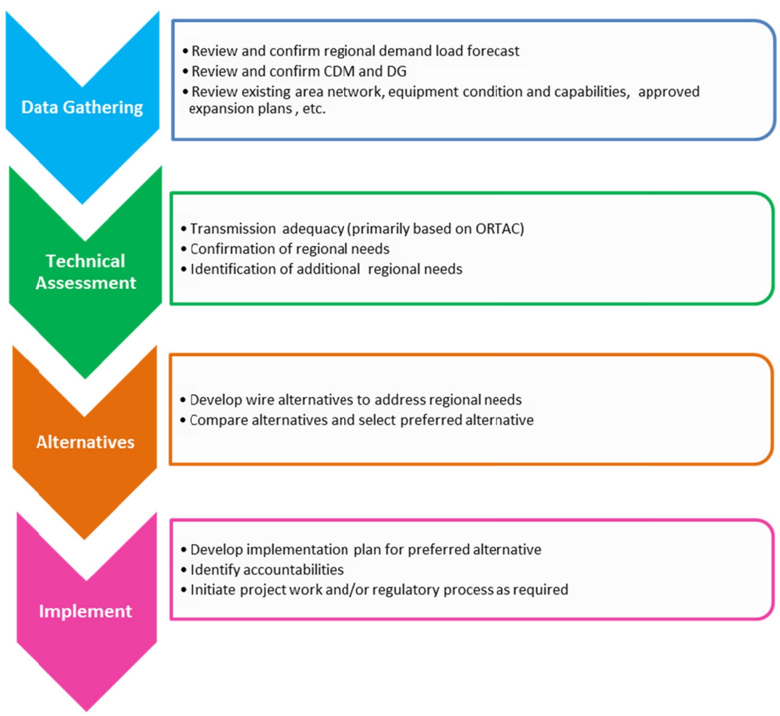


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE KWCG REGION COMPRISES OF THE CITIES OF KITCHENER, WATERLOO, CAMBRIDGE AND GUELPH, PORTIONS OF OXFORD AND WELLINGTON COUNTIES AND THE TOWNSHIPS OF NORTH DUMFRIES, PUSLINCH, WOOLWICH, WELLESLEY AND WILMOT AS SHOWN IN FIGURE 3-1.

The main sources of electricity into the KWCG Region are from four Hydro One stations: Middleport TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers by 24 step-down transformer stations. Figure 3-2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener-Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system. Appendix A lists all step-down transformer stations in the KWCG Region, Appendix B lists all transmission circuits in the KWCG Region and Appendix C lists LDCs in the KWCG Region.

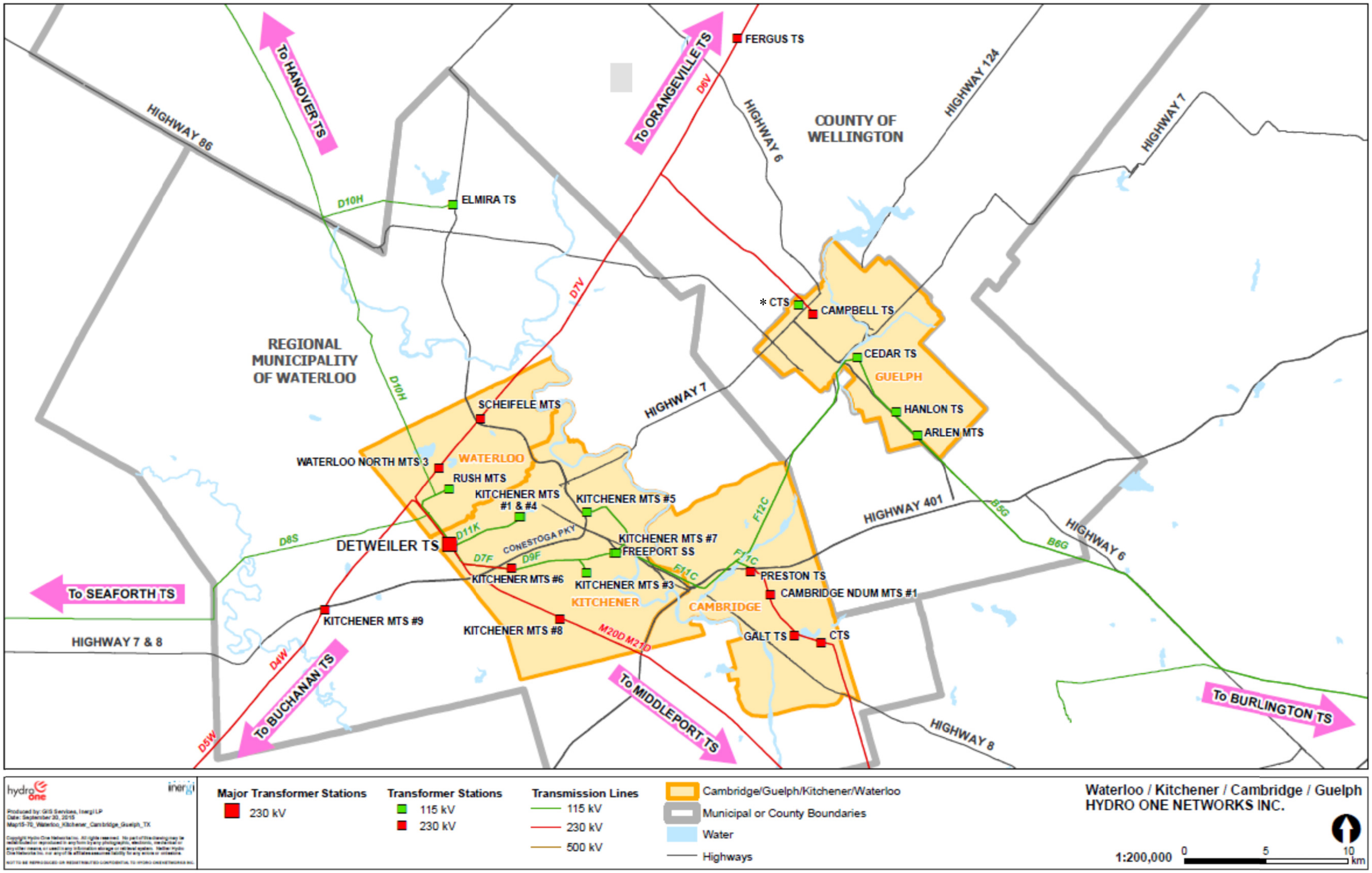


Figure 3-1 Geographical Area of the KWCG Region with Electrical Layout

*CTS relocated to the distribution system as part of the GATR project

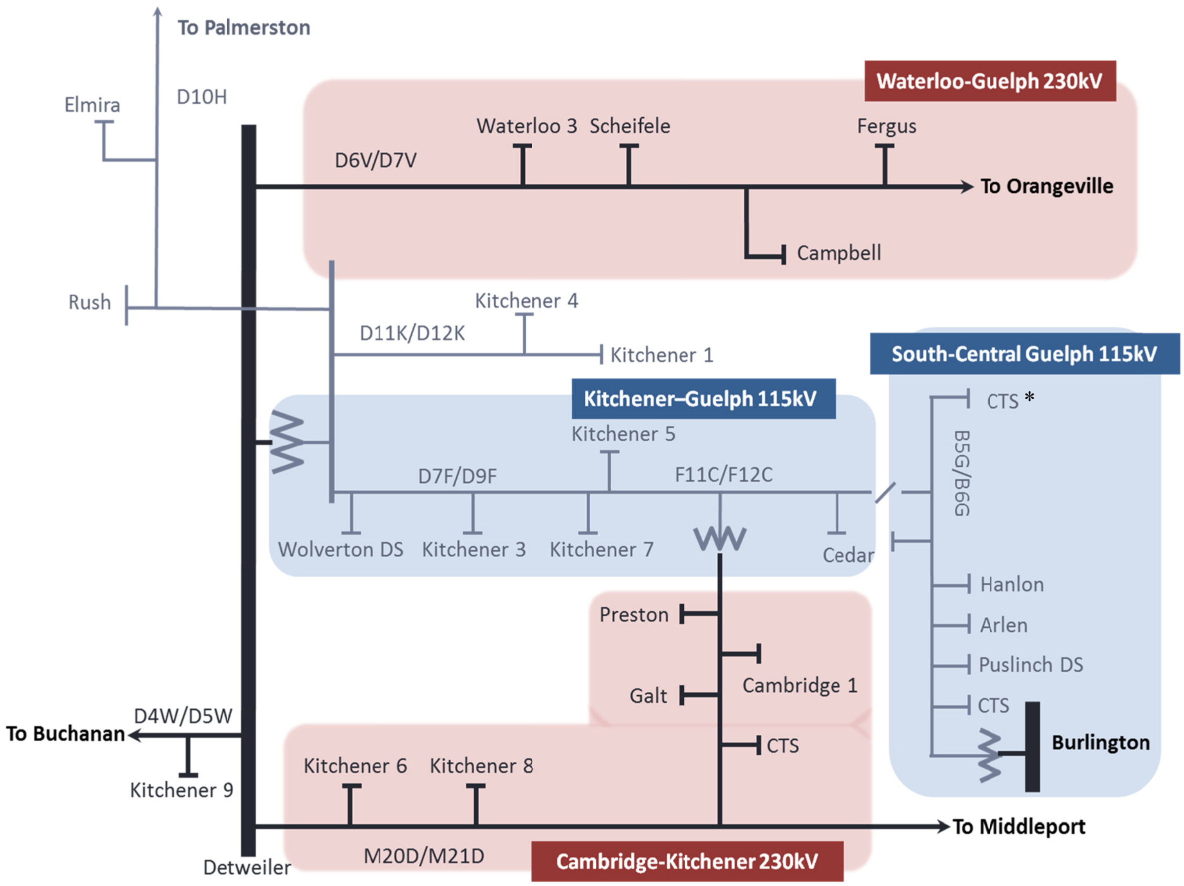


Figure 3-2 KWCG Single Line Diagram

*CTS relocated to the distribution system as part of the GATR project

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE KWCG REGION.

These projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For transmission voltage level transformation capacity needs:

- 250 MVA 230/115 kV autotransformer T4 at Burlington TS replaced in 2006
- 250 MVA 230/115 kV autotransformer T6 at Burlington TS replaced in 2009

For distribution voltage level transformation capacity needs:

- Kitchener MTS#9 connected to replace the Detweiler TS DESN in 2010
- Arlen MTS connected in 2011

For reactive and voltage support needs:

- a 13.8 kV shunt capacitor bank installed at Cedar TS in 2006
- a 230 kV shunt capacitor bank installed at Detweiler TS in 2007
- a 230 kV shunt capacitor bank installed at Orangeville TS in 2008
- a 230 kV shunt capacitor bank installed at Burlington TS in 2010
- a 115 kV shunt capacitor bank installed at Detweiler TS in 2012

For transmission circuit capacity needs:

- M20D/M21D circuit sections capacity increased by sag limit mitigation in 2014

For transmission load security needs:

- Freeport SS installed to sectionalize circuits D7G/D9G (Detweiler TS by Cedar TS) in 2008

For transmission load restoration needs:

- 250 MVA 230/115 kV autotransformer T2 installed at Preston TS in 2007

The following projects are underway:

- Guelph Area Transmission Reinforcement (GATR) project that entails the extension the 230kV circuits D6V/D7V to Cedar TS; the installation of two new 250MVA, 230/115kV autotransformers at Cedar TS; and the installation of two 230 kV in-line switches onto circuits D6V/D7V at Guelph North Junction. This project reinforces the Kitchener-Guelph and South-Central Guelph 115kV sub-systems as well as improves restoration capability to the Waterloo-Guelph 230 kV sub-system. This project is identified in the IESO KWCG IRRP, reference [1].

- The installation of a 13.8 kV series reactor to mitigate short circuit levels at Arlen MTS. This project was identified in the RIP phase.

- The installation two new 230kV in-line switches onto circuits M20D/M21D near Galt Junction to improve restoration capability in the Cambridge-Kitchener 230 kV sub-system. This project is identified in Hydro One's KWCG Adequacy of Transmission Facilities & Transmission Plan 2016-2025 report, reference [2]/Appendix F as well as reference [1].

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the KWCG Region is forecast to increase at an average rate of approximately 1.7% annually between 2015 and 2025. The growth rate varies across the Region with most of the growth concentrated in the cities of Waterloo and Guelph, each at an average rate of 2.5% over the next ten years.

Figure 5-1 shows the KWCG Region's planning load forecast (summer net, regional-coincident extreme weather peak). The regional-coincident (at the same time) forecast represents the total peak load of the 24 step-down transformer stations in the KWCG Region. By 2025 the forecasted coincident regional peak load is approximately 1765 MW.

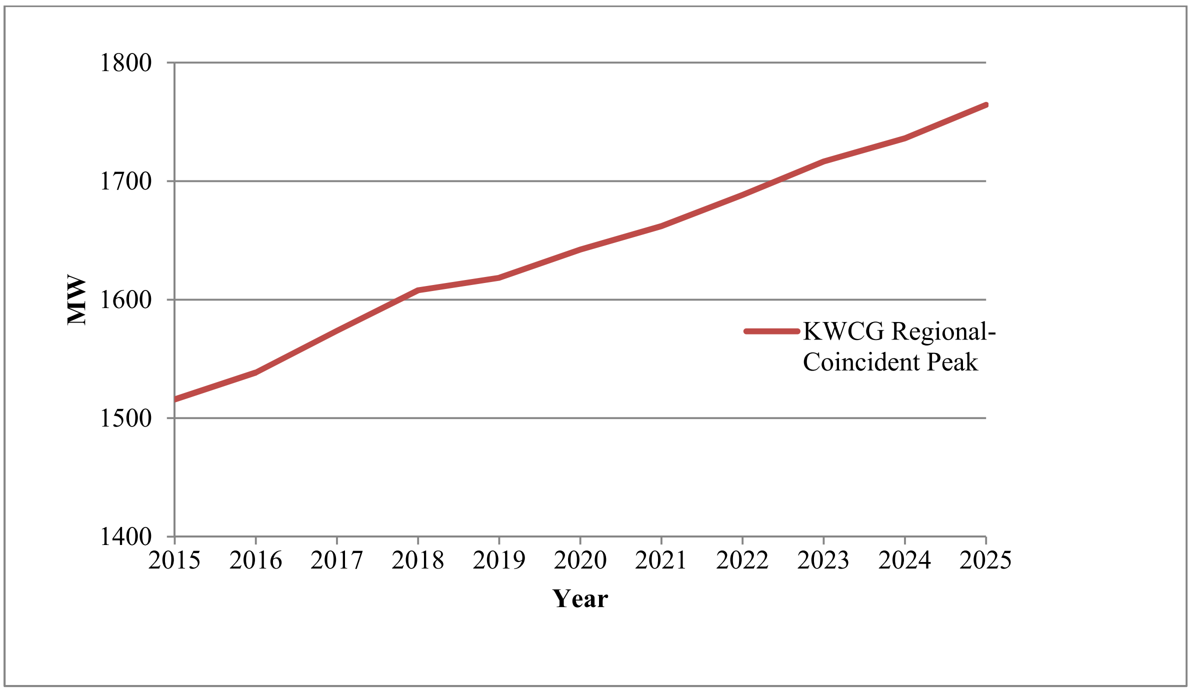


Figure 5-1 KWCG Region's Planning Forecast

The KWCG 2015 RIP planning load forecast is provided in Appendix D and is based upon the KWCG IRRP planning load forecast prepared by the IESO and was reaffirmed by the Working Group upon initiation of the RIP phase. In the IRRP phase, the LDC's provided the IESO with a 10 year gross, normal weather, regional-coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective CDM capacity, applying an extreme weather factor and then subtracting the effective DG capacity. Further details regarding the CDM and connected DG are provided in reference [1]. The RIP forecast is identical to the IRRP forecast except as otherwise noted in Appendix D.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

1) The Study period for the RIP assessment is 2015-2025.
2) All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
3) Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
5) Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR), while some LDCs use different methodologies for determining transformer station LTR.
6) Adequacy assessment is done as per the Ontario Resource and Transmission Adequacy Criteria ("ORTAC").

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND DELIVERY STATION FACILITIES SUPPLYING THE KWCG REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle two regional assessments have been conducted for the KWCG Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's KWCG Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Adequacy of Transmission Facilities and Transmission Plan 2016-2025 – dated April 1, 2015 with revision 1 – dated October 30, 2015[2] (please see Appendix F)

The IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Guelph Area Transmission Reinforcement (GATR) project was initiated to provide adequate load supply capability to the KWCG area while the IRRP study was still underway. A detailed description and status of the GATR project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the KWCG Region assuming the GATR project is in-service. Sections 6.1-6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Medium Term Regional Needs

Type	Section	Needs	Timing
Needs Identified in the IRRP [1] and the Adequacy Report [2]			
Transmission Circuit Capacity	7.1.1	South-Central Guelph 115 kV sub-system- Capacity of 115kV circuits B5G/B6G	Immediate
	7.1.2	Kitchener–Guelph 115 kV sub-system – Capacity of 115kV circuits D7F/D9F and F11C/F12C	Immediate
Load Restoration	7.1.3	Waterloo-Guelph 230 kV sub-system	Immediate
	7.2.1	Cambridge-Kitchener 230 kV sub-system	Immediate
Step-down Transformation Capacity	7.3.1	Waterloo North Hydro Inc.	2018
Additional Needs identified in RIP Phase			
Station Short Circuit Capability	7.4.1	Arlen MTS: Short Circuit capability	2016

6.1 230 kV Transmission Facilities

All 230 kV transmission circuits in the KWCG Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of the Ontario's transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the Hamilton, Niagara and GTA areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-2):

1) Detweiler TS to Orangeville TS 230 kV transmission circuits D6V/D7V – supplies Fergus TS, Campbell TS, Waterloo North MTS#3 and Scheifele MTS
2) Detweiler TS to Middleport TS 230 kV transmission circuits M20D/M21D – supplies Kitchener MTS #6, Kitchener MTS # 8, Cambridge MTS #1, Galt TS, Preston TS and Customer #1 CTS
3) Detweiler TS to Buchanan TS 230 kV transmission circuits D4W/D5W – supplies Kitchener MTS#9.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period. Refer to section 3.4.2 of Appendix F for the detailed analysis.

6.2 500/230 kV and 230/115 kV Transformation Facilities

Bulk power supply to the KWCG Region is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV autotransformers. The number and location of these autotransformers are as follows:

1) Two 500/230 kV autotransformers at Middleport TS
2) Four 230/115 kV autotransformers at Burlington TS
3) Three 230/115 kV autotransformers at Detweiler TS
4) Two 230/115 kV autotransformers at Cedar TS
5) One 230/115 kV autotransformer at Preston TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the auto-transformation supply capacity is adequate over the study period. Refer to section 3.4.1 of Appendix F for the detailed analysis.

6.3 Supply Capacity of the 115 kV Network

The KWCG Region contains five pairs of double circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Detweiler TS to Freeport SS 115 kV transmission circuits D7F/D9F – supplies Wolverton DS, Kitchener MTS #3, Kitchener MTS#7
2) Freeport SS to Cedar TS 115 kV transmission circuits F11C/F12C – supplies Kitchener MTS#5 and Cedar T1/T2 transformers
3) Burlington TS to Cedar TS 115 kV transmission circuits B5G/B6G – supplies Puslinch DS, Arlen MTS, Hanlon TS, Customer #2 CTS and Cedar T7/T8 transformers
4) Detweiler TS 115 kV radial transmission circuit D11K/D12K – supplies Kitchener MTS#1 and Kitchener MTS#4
5) Detweiler TS to Seaforth TS/Hanover TS 115 kV transmission circuit D8S/D10H with Normally Open (N/O) points – supplies Rush MTS and Elmira TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the supply capacity of the 115 kV network is adequate over the study period. Refer to section 3.4.3 of Appendix F for the detailed analysis.

6.4 Step-down Transformer Stations

There are 24 step-down transformer stations within the KWCG Region. Twenty-two supply electricity to LDCs and two are transmission-connected industrial customer stations. These stations are listed within the load forecast in Appendix D. Of those 24 stations, 15 of them are owned and operated by the LDCs.

As part of the IRRP, step-down transformation station capacity was reviewed and resulted in the IRRP forecast which was reaffirmed by the Working Group for use in the RIP phase. According to the load forecast, Waterloo North Hydro anticipates requiring additional step-down transformation capacity in 2018.

6.5 Other Items Identified During Regional Planning

6.5.1 Customer Impact Assessment for the GATR project

Based on the Customer Impact Assessment [3] for the GATR project, Guelph Hydro identified the need to mitigate short circuit levels at Arlen MTS in order to ensure the short circuit levels remain within the TSC limits and equipment ratings. The project need date is May 2016 so as to correlate with the completion of the GATR project.

6.5.2 System Impact Assessment for the GATR Project

A System Impact Assessment ("SIA") [4] was performed for Hydro One's application to the IESO for the Guelph Area Transmission Reinforcement (GATR) project.

Several findings emanated from the SIA report due to conservative assumptions made for the Bulk Power System. The Working Group has reviewed these findings and recommends that the assumptions be looked at in greater detail within a Bulk Power System study. If the Bulk Power System study results in regional needs then an early trigger of the next Regional Planning cycle may occur.

6.5.3 Load Restoration to the Cambridge area

The IRRP recommended Hydro One to continue to explore options with Cambridge and North Dumfries Hydro ("CND") to further improve the load restoration capability to the Cambridge area. During the RIP phase Hydro One presented to CND a detailed explanation of its capability to restore power to transformer stations that service the Cambridge area. Based on this discussion, CND and Hydro One have agreed that, at this time, no additional infrastructure is required and the restoration capability afforded by the GATR project and the 230 kV in-line switches at Galt Junction is acceptable for the study period.

6.6 Long-Term Regional Needs

The IRRP examined high-growth and low-growth scenarios to identify long-term needs. Under the high-growth scenario, there is sufficient transmission capacity afforded by the GATR project to meet demand in the long-term; however the need for additional step-down transformation capacity may arise. LDC's to closely monitor their load to determine the timing of potential step-down transformation needs. Under the low-growth scenario, no needs were identified in the long-term.

Consistent with the IRRP, the Working Group did not identify any additional long-term needs during the RIP phase. If new long-term needs were to arise, there is sufficient time to assess them in the next planning cycle which can also be started earlier to make timely investment decisions..

7. REGIONAL PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE KWCG REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP AS WELL AS THE NEEDS IDENTIFIED DURING THE RIP PHASE.

7.1 Transmission Circuit Capacity and Load Restoration

7.1.1 South-Central Guelph 115 kV Sub-system

The South-Central Guelph area is supplied by the 115 kV double circuit line B5G/B6G. As per section 6.2.1 of the IRRP, historical peak demand on the B5G/B6G line has already exceeded the 100 MW line Load Meeting Capability ("LMC").

7.1.2 Kitchener-Guelph 115 kV Sub-system

The Kitchener-Guelph area is supplied by two 115 kV double-circuit lines D7F/D9F and F11C/F12C supported by 230/115 kV autotransformers at Detweiler TS and Preston TS. As per section 6.2.1 of the IRRP, the planning forecast peak demand in the Kitchener-Guelph 115 kV sub-system will exceeded the 260 MW line LMC by summer 2014.

7.1.3 Waterloo-Guelph 230 kV Sub-system

As per section 6.2.2 of the IRRP, the transmission infrastructure supplying load in the Waterloo-Guelph 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, D6V and D7V.

7.1.4 Recommended Plan and Current Status

To address the transmission circuit capacity needs for the South-Central Guelph 115 kV sub-system and the Kitchener-Guelph 115 kV sub-system, the IRRP Working Group recommended reinforcement of the 115 kV transmission system by introducing a new 230 kV – 115 kV injection point. The new injection point is to be located at Cedar TS using two new 230 kV/115 kV autotransformers in conjunction with a 5 km extension of the existing 230 kV double-circuit transmission line, D6V/D7V from Campbell TS to Cedar TS. This reinforcement is covered under the GATR project.

To address the load restoration need of the Waterloo-Guelph 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches near Guelph North Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is also covered under the GATR project.

Current Status of the GATR Project

Hydro One initiated construction on the GATR project in fall 2013 following the OEB approval in September 2013. The project has three components:

- Campbell TS x Cedar TS: Extend the 230 kV D6V/D7V tap from Campbell TS to Cedar TS. This requires replacing approximately a 5 km section of the existing 115 kV double circuit transmission section between CGE Junction and Campbell TS with a new 230 kV double circuit transmission line,
- Cedar TS: Install two new 230/115 kV autotransformers and associated 115 kV switching facilities at Cedar TS. Connect 115 kV switching facilities to the existing B5G/B6G line and the F11C/F12C at Cedar TS.
- Guelph North Junction: Install two in-line 230 kV switches at Guelph North Jct.

This investment will provide for sufficient 230/115 kV autotransformation capacity beyond the study period. The current in-service date of the project is May 2016.

The cost of this project is approximately $95 million. The project is a transmission pool investment as the autotransformers provide supply to all customers in the Region.

7.2 Load Restoration

7.2.1 Cambridge-Kitchener 230 kV Sub-system

As per section 6.2.2 of the IRRP and the section 3.4.8 of the Adequacy of Transmission Facilities report, transmission infrastructure supplying load in the Cambridge-Kitchener 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, M20D and M21D.

7.2.2 Recommended Plan and Current Status

To address the load restoration need of the Cambridge-Kitchener 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches on the M20D/M21D line near Galt Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is covered under the M20D/M21D Install 230 kV In-line Switches project.

Current Status of the 230 kV In-Line Switches near Galt Junction

Hydro One has established a project to install the two 230 kV in-line switches onto the M20D/M21D double circuit line. One set of switches to be installed onto each circuit. One set of switches to be installed north of the Junction while the other to be installed south of Galt Junction. The switches will enable

Hydro One to quickly isolate a problem on either side of the junction and initiate the restoration of load to the Cambridge-Kitchener 230 kV sub-system.

The project is currently in the detailed design and estimation phase which also includes real estate negotiations. The cost of this project is approximately $6 million and it will be a transmission pool investment. The planned in-service date is May 2017.

7.3 Step-down Transformation Capacity

7.3.1 Waterloo North Hydro

The RIP/IRRP planning load forecast indicates that additional step-down transformation capacity is required by 2018, specifically Waterloo North Hydro's MTS #4.

7.3.2 Recommended Plan and Current Status

To address step-down transformation capacity needs of Waterloo North Hydro, Waterloo North Hydro will, wherever possible, manage load growth by maximizing the utilization of existing stations by increasing distribution load transfer capability between those stations and will continue to explore opportunities for CDM and DG. In addition Waterloo North Hydro will also explore, with other LDCs, opportunities to coordinate possible joint use and development of step-down transformer stations in the Region over the long term. With this in mind, additional step-down transformation capacity is not anticipated prior to 2024. This need will be reviewed in the next cycle of regional planning.

7.4 Station Short Circuit Capability

7.4.1 Arlen MTS

Arlen MTS is a 115/13.8 kV step-down transformer station owned by Guelph Hydro. As a result of the new 230/115 kV injection point afforded by the GATR project, the short circuit levels at Arlen MTS's 13.8 kV bus will exceed the TSC limit and equipment capability.

7.4.2 Recommended Plan and Current Status

To address the station short circuit capability need at Arlen MTS, Guelph Hydro will install series reactors to bring station short circuit levels within TSC limits and within equipment ratings.

Current Status of Short Circuit Mitigation

Guelph Hydro has initiated a project to install series reactors to bring station short circuit levels within TSC limits and equipment ratings. The cost of this project is $0.95 million and the expected completion date is May 2016 so as to correlate with the completion of the GATR project.

8. CONCLUSIONS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE KWCG REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

Six near and mid-term needs were identified for the KWCG Region. They are:

I. Transmission capacity in the South-Central Guelph 115 kV sub-system
II. Transmission capacity in the Kitchener-Guelph 115 kV sub-system
III. Load restoration capability in the Waterloo-Guelph 230 kV sub-system
IV. Load restoration capability in the Cambridge-Kitchener 230 kV sub-system
V. Step-down transformation capacity for Waterloo North Hydro
VI. Station Short Circuit Capacity at Arlen MTS

This RIP report addresses all six of these needs. Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near and mid-term needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
1	Guelph Area Transmission Reinforcement	Construction in the final stages	Hydro One	May 2016	$95M	I, II, III
2	Mitigate Short Circuit Levels at Arlen MTS	Construction underway	Guelph Hydro	May 2016	$0.95M	VI
3	M20D/M21D – Install 230 kV In-line Switches	Transmitter to carry out this work	Hydro One	May 2017	$6M	IV
4	Waterloo North Hydro: MTS #4	LDC to monitor growth	Waterloo North Hydro	2024	TBD	V

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1] Independent Electricity System Operator, Kitchener-Waterloo-Cambridge-Guelph Region Integrated Region Resource Plan, 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/KWCG/2015-KWCG-IRRP-Report.pdf

[2] Hydro One Networks Inc., Kitchener-Waterloo-Cambridge-Guelph Area – Adequacy of Transmission Facilities and Transmission Plan 2016-2025, 1 April 2015, revised 30 October 2015.

[3] Hydro One Networks Inc., Customer Impact Assessment Guelph Area Transmission Refurbishment Project, 28 May 2013,

[4] Independent Electricity System Operator, System Impact Assessment, CAA ID: 2012-478, Project: Guelph Area Transmission Refurbishment, 17 May 2013.
http://www.ieso.ca/Documents/caa/CAA_2012-478_GATR_Final_Report.pdf

Appendix A. Step-Down Transformer Stations in the KWCG Region

Station	Voltage (kV)	Supply Circuits
Waterloo-Guelph 230 kV sub-system		
Fergus TS	230 kV	D6V/D7V
Scheifele MTS	230 kV	D6V/D7V
Waterloo North MTS #3	230 kV	D6V/D7V
Campbell TS	230 kV	D6V/D7V
Cambridge-Kitchener 230 kV sub-system		
Kitchener MTS #6	230 kV	M20D/M21D
Kitchener MTS #8	230 kV	M20D/M21D
Cambridge MTS #1	230 kV	M20D/M21D
Preston TS	230 kV	M20D/M21D
Galt TS	230 kV	M20D/M21D
Customer #1 CTS	230 kV	M21D
Kitchener–Guelph 115 kV sub-system		
Wolverton DS	115 kV	D7F/D9F
Kitchener MTS #3	115 kV	D7F/D9F
Kitchener MTS #7	115 kV	D7F/D9F
Kitchener MTS #5	115 kV	F11C/F12C
Cedar TS (T1/T2)	115 kV	F11C/F12C
South-Central Guelph 115 kV sub-system		
Puslinch DS	115 kV	B5G/B6G
Arlen MTS	115 kV	B5G/B6G
Hanlon TS	115 kV	B5G/B6G
Cedar TS (T8/T7)	115 kV	B5G/B6G
Customer #2 CTS	115 kV	B5G
Other Stations in the KWCG Region		
Kitchener MTS #9	230 kV	D4W/D5W
Rush MTS	115 kV	D8S/D10H
Elmira TS	115 kV	D10H
Kitchener MTS #1	115 kV	D11K/D12K
Kitchener MTS #4	115 kV	D11K/D12K

Appendix B. Transmission Lines in the KWCG Region

Location	Circuit Designations	Voltage (kV)
Detweiler TS – Orangeville TS	D6V/D7V	230 kV
Detweiler TS - Middleport TS	M20D/M21D	230 kV
Detweiler TS - Buchanan TS	D4W/D5W	230 kV
Detweiler TS - Freeport SS	D7F/D9F	115 kV
Freeport SS - Cedar TS	F11C/F12C	115 kV
Burlington TS - Cedar TS	B5G/B6G	115 kV
Detweiler TS – Kitchener MTS #4	D11K/D12K	115 kV
Detweiler TS – Palmerston TS	D10H	115 kV
Detweiler TS – Seaforth TS	D8S	115 kV

Appendix C. Distributors in the KWCG Region

Distributor Name	Station Name	Connection Type
Cambridge and North Dumfries Hydro Inc.	Cambridge NDum MTS#1	Tx
	Galt TS	Tx
	Preston TS	Tx
	Wolverton DS	Dx
Centre Wellington Hydro Ltd.	Fergus TS	Dx
Guelph Hydro Electric System - Rockwood Division	Fergus TS	Dx
Guelph Hydro Electric Systems Inc.	Arlen MTS	Tx
	Campbell TS	Tx
	Cedar TS	Tx
	Hanlon TS	Tx
Halton Hills Hydro Inc.	Fergus TS	Dx
Hydro One Networks Inc.	Fergus TS	Tx
	Elmira TS	Tx
	Puslinch DS	Tx
	Wolverton DS	Tx
	Galt TS	Dx
Kitchener-Wilmot Hydro Inc.	Kitchener MTS#1	Tx
	Kitchener MTS#3	Tx
	Kitchener MTS#4	Tx
	Kitchener MTS#5	Tx
	Kitchener MTS#6	Tx
	Kitchener MTS#7	Tx
	Kitchener MTS#8	Tx
	Kitchener MTS#9	Tx
Milton Hydro Distribution Inc.	Fergus TS	Dx
Waterloo North Hydro Inc.	Elmira TS	Dx
		Tx
	Fergus TS	Dx
	Rush MTS	Tx
	Scheifele MTS	Tx
	Waterloo North MTS #3	Tx
	Preston TS	Dx
	Kitchener MTS#9	Dx
Wellington North Power Inc.	Fergus TS	Dx

Appendix D. KWCG Regional Load Forecast (2015-2025)

Table D-1 RIP Planning Demand Forecast (MW)

Station	LDC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS (1)	Cambridge & North Dumfries Hydro	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Kitchener MTS #6	Kitchener-Wilmot Hydro	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Wolverton DS	Hydro One Distribution	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Cedar TS T1/T2	Guelph Hydro	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cambridge MTS # 2 (2)	Cambridge & North Dumfries Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #5	Kitchener-Wilmot Hydro	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Cedar TS T7/T8	Guelph Hydro	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Puslinch DS	Hydro One Distribution	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Arlen MTS	Guelph Hydro	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo North MTS #3	Waterloo North Hydro	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
MTS #4(2)	Waterloo North Hydro	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Fergus TS	Hydro One Distribution	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Kitchener MTS #1	Kitchener-Wilmot Hydro	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Kitchener MTS #4	Kitchener-Wilmot Hydro	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Elmira TS (3)	Waterloo North Hydro/ Hydro One Distribution	38.0	32.6	33.5	33.3	34.8	35.4	36.0	36.8	38.4	39.0	40.6
Rush MTS	Waterloo North Hydro	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS (4)	Customer Station	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Station (Assumed Values)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Table D1 -is based upon KWCG 2015 IRRP Planning Load Forecast except as noted.

(1) Cambridge and North Dumfries Hydro ("CND") has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expected to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

(2) Both CND and Waterloo North Hydro ("WNH") are monitoring the load closely to determine the timing of potential transformation needs. For planning purposes, WNH has moved back the in service date of MTS #4 from 2018 to 2024. WNH is closely monitoring the need for additional transformation capacity to determine if the load growth indicated at MTS #4 in the forecast can be managed through a combination of improving transformer station interties, CDM and DG in the Waterloo Region. Where possible, these LDCs are exploring opportunities to coordinate possible joint use and development of step-down transformer station facilities in the KWCG Region over the long term.

(3) Updated to include Hydro One Distribution load

(4) Based on information provided by the transmission-connected customer

Appendix E. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Appendix F. KWCG Adequacy of Transmission Facilities and Transmission Plan 2016-2025

Revision 1

KITCHENER/WATERLOO/CAMBRIDGE/GUELPH AREA

ADEQUACY OF TRANSMISSION FACILITIES

AND

TRANSMISSION PLAN 2016 – 2025

October 30, 2015

Prepared by Hydro One Networks Inc. in Consultation with the KWCG Working Group

Foreword

This report is the result of a joint study by KWCG Working Group. It has been prepared by Hydro One Networks in consultation with the Working Group.

The working group members were:

Entity	**Member**
Kitchener-Wilmot Hydro	Shaun Wang L. Frank G. Cameron
Waterloo North Hydro Inc.	Herbert Haller David Wilkinson Dorothy Moryc
Cambridge & North Dumfries Hydro	Ron Sinclair Shawn Jackson
Guelph Hydro Electric System Inc.	Michael Wittemund K. Marouf Eric Veneman
Hydro One Distribution	Charlie Lee
Ontario Power Authority	Bob Chow Bernice Chan
Independent Electricity Operator	Peter Drury
Hydro One Networks Inc.	Alessia Dawes Farooq Qureshy Emeka Okongwu Qasim Raza

The preferred plan has been selected based on technical and economic considerations. The issue of cost allocation between utilities was not addressed.

Prepared by: Qasim Raza – Transmission Planning Officer

Reviewed by: Alessia Dawes – Senior Transmission Planning Engineer

Approved by: Farooq Qureshy – Manager, Transmission System Development, Central & East

October 30, 2015

Revision History

Revision	Date	Author	Description of change
1	October 30, 2015	Qasim Raza	Refreshed based on 2015 IRRP/RIP load forecast (April/August2015)
0	April 1, 2015	Alessia Dawes	Original- based on May 2013 forecast

TABLE OF CONTENTS

EXECUTIVE SUMMARY

In 2010 an integrated regional planning study was initiated to assess the electricity supply and reliability over a twenty year period for the Kitchener-Waterloo-Cambridge-Guelph (KWCG) areas and continues to be conducted by a Working Group led by the Ontario Power Authority (OPA) and includes staff from the Independent Electricity System Operator (IESO), Hydro One Networks Inc., Kitchener-Wilmot Hydro, Waterloo North Hydro, Cambridge & North Dumfries Hydro, Guelph Hydro Electric Systems Inc. and Hydro One Distribution.

The early results of the integrated regional planning study identified the need to reinforce supply capacity for the South-Central Guelph and the City of Cambridge over the near and medium term. It also identified the need to minimize the impact of double circuit interruptions in the area[1]. As a result, the Working Group recommended two transmission projects in conjunction with conservation and distributed generation:

1. The Guelph Area Transmission Reinforcement (GATR) project – comprising a new 230/115kV autotransformer station at Guelph Cedar TS, upgrading the circuit section between Campbell TS and CGE Junction to 230 kV and in-line switching on the Orangeville TS x Detweiler TS 230kV circuits D6V/D7V – to reinforce supply to South Central Guelph,
2. The Preston TS Autotransformer Project – comprising the installation of a second 230/115kV autotransformer at Preston TS - to reinforce supply to the City of Cambridge.

Work on the GATR project was started in 2014 following approval from the Ontario Energy Board and the Ministry of Environment. The project's planned in-service date is June 2016.

For the Preston project, the OPA issued Hydro One a hand off letter to develop a "Wires" solution to improve the supply to the Cambridge area and to facilitate the connection of a future Cambridge and North Dumfries Hydro transformer station by 2018.

This report presents the results of Hydro One led "Wires" study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016. The main conclusions of the report are as follows:

- The supply capability to the KWCG 115kV area has been significantly increased to meet all 2025 forecast loads by the addition of the GATR project. The need for the Preston autotransformer can be deferred to beyond 2025.
- There is inadequate load restoration capability for load connected to Middleport TS x Detweiler TS 230kV double circuit line M20D and M21D

This report recommends that the most cost effective plan to improve load restoration capability for load connected to circuits M20/21D is to install 230 kV in-line switches onto circuits M20/21D.

[1] OPA Submission to the OEB for the GATR Project – Document EB-2013-0053 dated March 8, 2013 entitled, "Kitchener-Waterloo-Cambridge-Guelph Area

1.0 INTRODUCTION

This transmission adequacy assessment focused on the electrical supply to the municipalities of Kitchener, Waterloo, Cambridge and Guelph and their surrounding areas of Ontario, collectively referred to as the KWCG area in this report. Its primary focus was to confirm the near and mid-term transmission needs for the area and to provide a 10-year transmission plan in order satisfy those Needs.

Geographically, the KWCG area consists of 4 municipalities – Kitchener, Waterloo, Cambridge, Guelph and portions of two counties - Perth and Wellington. Hydro One Networks Inc. is the sole high voltage transmitter in the KWCG area; however the low voltage distribution of electricity in the KWCG area is carried out by Cambridge and North Dumfries Hydro Inc., Guelph Hydro Electric System Inc., Hydro One Distribution, Kitchener-Wilmot Hydro Inc., and Waterloo North Hydro. A geographic map of the area is shown in Appendix A, Map 1 while an electrical map of the area is shown in Appendix A, Map 2.

The KWCG area is a major regional load centre in Ontario. The area has a well-established history in manufacturing and technology. The area peak load is approximately 1400 MW.

This report presents the results of the Hydro One led “Wires” study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016.

2.0 EXISTING TRANSMISSION INFRASTRUCTURE

2.1 TRANSMISSION IN KWCG

Electrical Supply in this area is provided through 230 kV and 115 kV transmission lines and step down transformation facilities (transmission stations, TS) as show in Appendix A, Map 2.

The main sources of electricity into the KWCG Region are Middleport TS, Detweiler TS, Orangeville TS, Cedar TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. The KWCG Region transmission system is connected as follows:

- Two 230 kV circuits (D6V/D7V) that run North-East from Detweiler TS to Orangeville TS that supply five load serving stations;
- Two 230 kV circuits (M20/21D) that run South-East from Detweiler TS to Middleport TS that supply five load serving stations and one transmission-connected customer;
- Two 230 kV circuits (D4W/D5W) that run South-West from Detweiler TS to Buchanan TS (in the “London area”) that supply one load serving station;
- Four 115 kV circuits (D7F/D9F, F11C/F12C) that run East-West: D7/9F from Detweiler TS to Freeport SS that supply three load serving stations and F11/12C from Freeport SS to Cedar TS that supply one load serving station;
- Two 115 kV circuits (B5G/B6G) that run North-West from Burlington TS to Cedar TS that supply three load serving stations and one transmission-connect customer;
- Two 115 kV radial circuits (D11K/D12K) emanating East from Detweiler TS that supply two load serving stations; and,
- Two 115 kV circuit (D8S and D10H) emanating North from Detweiler TS that supply two load serving stations in the KWCG area.

Voltage support is provided in the area by:

- Four high voltage shunt capacitor banks and one SVC at Detweiler TS
- Four high voltage shunt capacitor banks at Middleport TS
- Three high voltage shunt capacitor banks at Burlington TS
- One high voltage shunt capacitor bank at Orangeville TS
- 43.2 MVar low voltage station shunt capacitor at Galt TS
- 21.6 MVar low voltage station shunt capacitors at Campbell TS
- 59.81 MVar low voltage station shunt capacitors at Cedar TS
- 9.92 MVar low voltage station shunt capacitors at Elmira TS
- Low voltage feeder shunt capacitors were lumped at: C&ND MTS#1, Waterloo North Hydro MTS #3, Scheifele MTS

All stations in the KWCG Region were considered in the analysis to determine the adequacy of the existing transmission system. Transformation capacity at individual load serving stations was previously analyzed by the OPA as part of the Integrated Regional Resource Plan (IRRP). The result of that analysis was a load forecast that included proposed new stations, as shown in Appendix C. Therefore, transformation capacity at individual load serving stations was not considered in this study.

2.2 TRANSMISSION-CONNECTED GENERATION

There are no existing large-scale transmission-connected generation plants in the KWCG area; however two contracted renewable transmission-connected wind farms were included in the study area and are listed in Appendix B.

3.0 ADEQUACY OF EXISTING TRANSMISSION INFRASTRUCTURE IN KWCG AREA

3.1 STUDY ASSUMPTIONS

Assumptions were made in order to assess the effects of contingencies to verify the adequacy of the transmission system. The assumptions used in the study were:

1. A 10 year load forecast: years 2016 to 2025; shown in Appendix C
2. Forecasted loads were provided by the LDC's in MW. The MVAR portion of the load was set to 40% of the MW load which is a reasonable assumption to achieve a power factor of 0.9 at the defined meter point of load serving transformer stations (TS, CTS, MTS)
3. A summer assessment was performed as the KWCG area is summer load peaking while the equipment is at its lowest rating during summer ambient conditions. This was deemed to be the most conservative approach;
4. Equipment continuous and Limited Time Ratings (LTR) were based on an ambient temperature of 35°C for summer and a wind speed of 4 km/hour;
5. The Guelph Area Transmission Reinforcement (GATR) project would be in-service in June 2016;
6. Circuits M20D and M21D are assigned their updated long-term emergency rating (LTE) based on a maximum temperature of 127°C;
7. Simulation of year 2025 load forecast was performed as it was the maximum loading of the area for the duration of the study period; year 2016 was simulated as necessary;
8. Waterloo North Hydro's Snider MTS #4 (MTS #4) will connect to 230 kV circuit D6/7V between Scheifele MTS and Guelph North Jct., projected in-service date 2024 (refer to Note 2 in Appendix C, Table C1)
9. The flows on Ontario's major internal transmission interfaces were assumed as follows:
   - FETT ~ 4500 MW
   - FS ~1250 MW
   - FABCW ~ 5800MW
   - NBLIP ~ 1650 MW (the slightly high NBLIP was offset by the lower FABCW)
   - QFW ~ 1550 MW

3.2 STUDY CRITERIA

The adequacy of the transmission system is assessed as per the IESO Ontario Resource and Transmission Assessment Criteria, Issue 5.0.

3.3 LOAD FORECAST

The load forecast used in this assessment is the KWCG 2015 RIP forecast as shown in Appendix C. This summer forecast is an extreme weather, area coincident, net, peak load forecast.

The KWCG 2015 RIP forecast is based upon the KWCG 2015 IRRP forecast. The LDC's provided the IESO with a 20 year gross, normal weather, area coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective conservation and demand management (CDM) capacity, applying an extreme weather factor and then subtracting the effective Distribution Generation (DG) capacity.

3.4 SUPPLY CAPACITY NEEDS

Single element contingencies were considered in assessing the adequacy and reliability of the local transmission system that serves the KWCG area. Figure 1 summarizes the local KWCG area Needs for the 10-year period under study. Appendices D, F and G detail the technical study and results.

At stations, within the KWCG area, classified as NPCC Bulk Power System (BPS) additional contingencies were considered to establish their impact to the local KWCG area. Appendix E details the technical study and results.

3.4.1 AUTO-TRANSFORMATION SUPPLY CAPACITY

There is no major generation station in the KWCG area. Hence, the majority of supply to the load is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV auto-transformers. The number and location of these auto-transformers are as follows:

- Two 500/230 kV autotransformers at Middleport TS
- Four 230/115 kV autotransformers at Burlington TS[2]
- Three 230/115 kV autotransformers at Detweiler TS
- Two 230/115 kV autotransformers at Cedar TS
- One 230/115 kV autotransformer at Preston TS

Single autotransformer contingencies were performed to assess the adequacy of the transmission system to supply bulk power into the KWCG area via the autotransformers for year 2025 loading.

The results indicate that there are no thermal overloads and no voltage violations for the loss of a single autotransformer.

[2] The loading of the autotransformers at Burlington TS is mainly driven by the load connected in the Burlington to Nanticoke area. Only a small percentage of the autotransformer load is due to local Guelph load and as such, analysis of the Burlington TS autotransformers was undertaken in the 'Burlington to Nanticoke' Regional Infrastructure Plan.

3.4.2 Supply Capacity of the 230 kV Network

The KWCG area contains three pairs of double circuit 230 kV lines: M20D/M21D, D6V/D7V and D4W/D5W.

Single circuit contingencies were performed to assess the adequacy of the local 230 kV transmission system for year 2025 loading[3].

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 230 kV circuit.

3.4.3 Supply Capacity of the 115 kV Network

The KWCG area contains five pairs of double circuit 115 kV lines: D7F/D9F, F11C/F12C, B5G/B6G, D11K/D12K and D8S/D10H.

Single circuit contingencies were performed to assess the adequacy of the local 115 kV transmission system for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 115 kV circuit. Appendix H details supply capacity on circuit D8S and D10H as request by the LDC.

3.4.4 Voltage Performance

Single circuit contingencies as well as single element HV shunt capacitor bank contingencies were performed to determine the overall voltage performance of the KWCG area for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for these contingencies. Appendix H details voltage performance at Elmira TS and Rush MTS as request by the LDC.

3.4.5 Load Security Analysis

The most stringent load security criterion that applies to the KWCG area states that with any two elements out of service:

- Voltage must be within applicable emergency ratings and equipment loading must be within applicable short-term emergency ratings;
- Load transfers to meet the applicable long-term emergency ratings must be able to be made in the time afforded by short-time ratings;
- Planned load curtailment or load rejection in excess of 150 MW is not permissible (except for local generation outages) and;

[3] Note, if another element such as an autotransformer, circuit or capacitor bank shared the same “switching position” and/or zone of protection with the circuit under contingency, both were removed from service.

- Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment or load rejection excluding voluntary demand management with any two transmission elements out of service.

There are three pairs of 230 kV double circuit lines and five pairs of 115 kV double circuit lines in the KWCG area. While one circuit of a double circuit line is out of service, the loss of the companion circuit in the pair would result in the loss of all load stations connected to the pair by configuration. Tables F1 and F2 in Appendix F illustrate the load lost due to configuration in both years 2016 and 2025.

There are five stations in the KWCG area that have autotransformers. Overlapping autotransformer contingencies were taken and Table F3 in Appendix F illustrates any load transfer requirements due to two overlapping autotransformer outages.

As seen in Appendix F, the load forecasted on all circuit pairs is less than 600 MW within the 10-year study period and the loss of two autotransformers within this local area does not result in equipment loading beyond their applicable emergency ratings; therefore there is no concern with Load Security in the KWCG area for the study period.

3.4.6 Load Restoration Capability Analysis

The load restoration criteria requires that the transmission system be planned such that following local area design criteria contingencies, the affected loads can be restored within the restoration times indicated below[4]:

- All load lost must be restored within 8 hours;
- Load lost in excess of 250 MW must be restored within 30 min; and
- Load lost between the amount of 150 MW and 250 MW must be restored within 4 hours.

Each pair of double circuit 230 kV and 115 kV lines were assessed to verify their load restoration capability. This assessment is detailed in Appendix G.

The results indicated the existing transmission system can adequately restore load to each circuit pair with the exception of M20/21D. Therefore, improvement to the restoration capability of load connected to circuits M20D and M21D is required.

3.4.7 Impact of Contingencies on the BPS to the KWCG Area

Northeast Power Coordinating Council (NPCC) Bulk Power System stations in the KWCG area are:

- Middleport TS 500 kV bus
- Middleport TS 230 kV bus
- Detweiler TS 230 kV bus

[4] As per ORTAC: “These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility.”

All elements connected to BPS buses are considered BPS facilities. Elements refer to circuit breakers, transmission lines, generators, transformers and reactive devices (e.g. SVC or capacitor bank).

Appendix E: Technical Results-Bulk Power System Considerations provides a list of BPS contingencies and the results. A *limited* number of BPS contingencies were performed in order to establish the impact of contingencies on the BPS to the local KWCG area.

Three NPCC Directory 1 contingency events were utilized in this study:

1. Simultaneous loss of two adjacent transmission circuits on a multiple circuit tower
2. Loss of any element with delayed fault clearing (a.k.a. Breaker Failure)
3. Loss of a critical element, followed by system adjustment, then loss of a critical element.

These BPS contingency events were applied to BPS buses only. The results can be summarized as follows:

- As per Table E3 and E5 when two of the three auto-transformers at Detweiler TS are not available the remaining auto-transformer may become overloaded. Since the loading of the remaining auto-transformer is within its 15-minute Short-Term Emergency Rating (STE) operational control actions can be taken to reduce the loading to within acceptable limits. Control actions could entail isolation of the faulted element e.g. circuit breaker, bus or transformer, and placing back in-service a healthy auto-transformer (at Detweiler TS and/or Preston TS). Another control action could entail opening of 115kV breakers at Freeport SS to redirect flows through the Cedar TS autotransformers.

3.4.8 Summary of Needs

Figure 1 illustrates the Needs timeline for the KWCG region.

Figure 1: Transmission Needs in the KWCG Area

4.0 Options to Address the Need

Options were considered to address the insufficient load restoration capability for loads connected to circuits M20D and M21D. These options are shown in Table 1. Although there are several metrics that can be utilized to measure and compare options, the simple metric "initial capital cost/MW of load restored" was selected because it compares the unit costs of remedial measures. This was deemed sufficient in order to select the preferred option

Table 1: Options to Improve M20/21D Load Restoration

Option	Options to Improve Restoration	Fault on the Main Line – Restorable Load (Note 1)	Fault on the Tap – Restorable Load (Note 1)	Initial Capital Cost (Note 3)	Initial Capital Cost/ MW Load Restored
--	Existing (Benchmark)	100 MW (Preston TS only)	100 MW (Preston TS only)	0	$0/MW
1	230 kV in-line switches on M20/21D at **Preston Junction**	100 MW (C&ND load only-Note 2)	100 MW (C&ND load only-Note 2)	$6M	$60k/MW
2	230 kV in-line switches on M20/21D at **Galt Junction** (main line)	368 MW - 484 MW	234 MW (100 MW via existing Preston Auto)	$6M	$12k/MW to $26k/MW
3	One 230 kV cap bank at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	140 MW (Note 4) (C&ND load only-Note 2)	140 MW (Note 4) (C&ND load only-Note 2)	$11M	$79k/MW
4	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	200 MW (Note 4) (C&ND load only-Note 2)	200 MW (Note 4) (C&ND load only-Note 2)	$21M	$105k/MW
5	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction** plus two 230 kV cap banks at Preston TS	280 MW (Note 4) (C&ND load only-Note 2)	280 MW (Note 4) (C&ND load only-Note 2)	$31M	$111k/MW

NOTE 1 Restorable load values are approximate values only as the actual amount of restorable load will depend on the prevailing system conditions and Operating/Control Centre protocols and priorities

NOTE 2 "C&ND load only" means that only those customers connected to Galt TS, C&ND MTS#1 and Preston TS will benefit. Cambridge and North Dumfries Hydro customers are the sole customers of these three stations.

NOTE 3 All prices are based on historical data: taxes extra, overhead extra, no escalation considered, no assumptions are made to feasibility or constructability, no assumptions made as to space requirements, real estate and environmental cost extra

NOTE 4 Restoration of 230 kV load (Cambridge and North Dumfries load) via the Preston TS auto-transformer may require operational measures on the 115 kV system to secure the transmission system to handle a subsequent contingency e.g. open the low voltage bus-tie breakers/switches at 115kV connected stations

5.0 DISCUSSION OF PREFERRED OPTIONS

5.1 PREFERRED OPTION TO IMPROVE RESTORATION TO M20/21D LOAD

Currently, loads connected to circuits M20/21D do not meet the restoration criteria.

Of the five options, option #2: 230 kV in-line switches on M20/21D at/near Galt Junction is the preferred option to satisfy the Need as it will provide the capability to restore the most load supplied from M20/21D.

Not only does Option #2 allow for more load to be restored, it provides for better operational flexibility; and is the most economical solution. As option 2 substantially meets the need by significantly improving the existing restoration capability, it is therefore the preferred option.

6.0 DEVELOPMENT PLAN

The transmission infrastructure development plan for the KWCG area is as followings:

1) <u>Immediate Action: Install 230 kV In-Line Switches</u>

Install 230 kV Load Interrupter type in-line switches on circuits M20D and M21D on the main line near Galt Junction. Note that load interrupter type switches cannot be used to interrupt fault current.

7.0 CONCLUSIONS

The following conclusions can be reached from the analysis performed by this study.

<u>Local Area Performance</u>

1. Improvement to the load restoration capability of transmission-connected customers on circuits M20D and M21D is required. The preferred option can be implemented by summer 2017.

<u>BPS Performance</u>

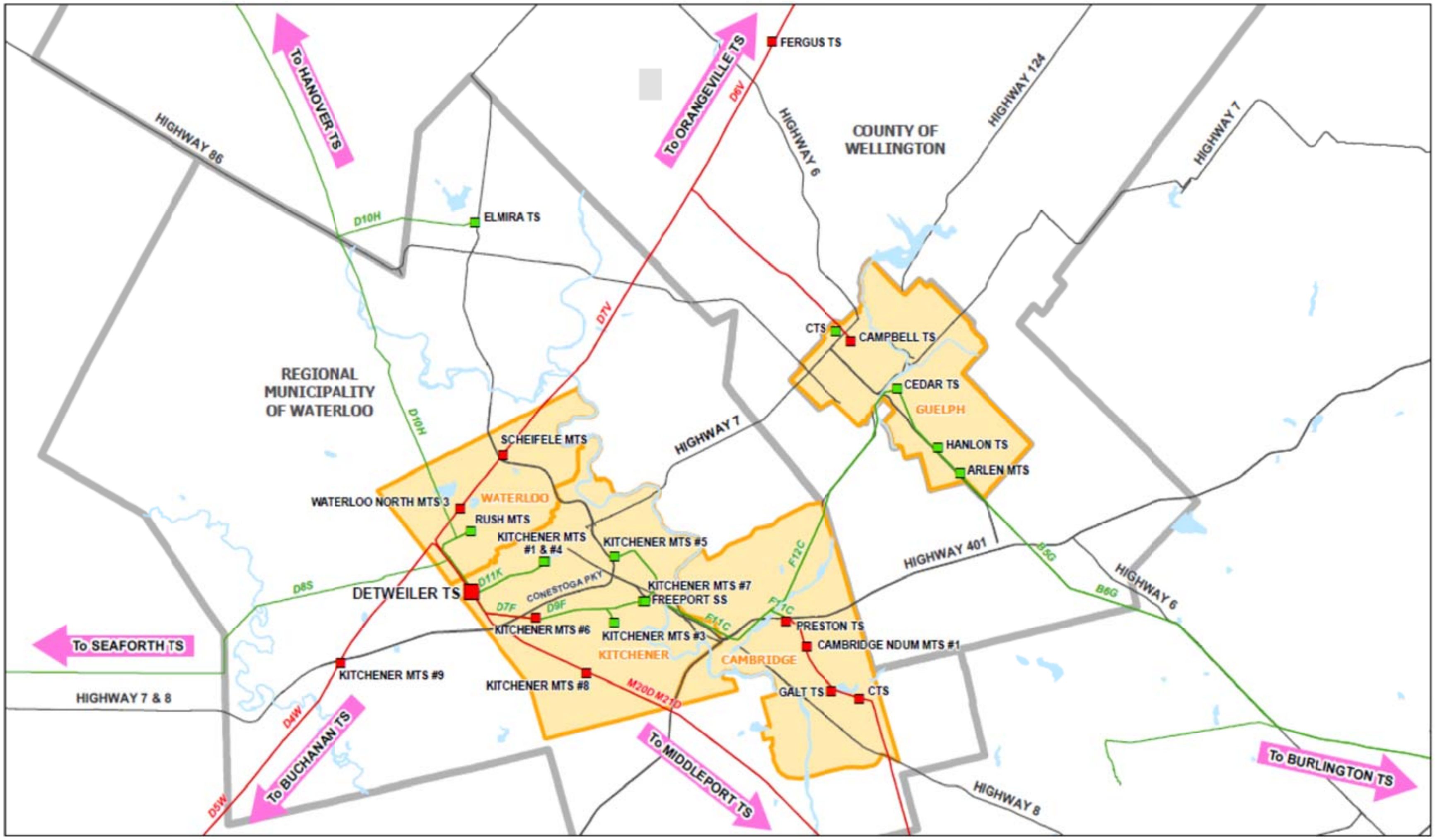
2. Autotransformer T2 at Detweiler TS is expected to be at 104.4% of LTE loading for year 2016 for the following contingency:
    i. Detweiler T4 outage plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS). Since the post-contingency flow is below the auto-transformer STE, operational control actions can be taken to reduce loading to within the LTE rating.

8.0 RECOMMENDATIONS

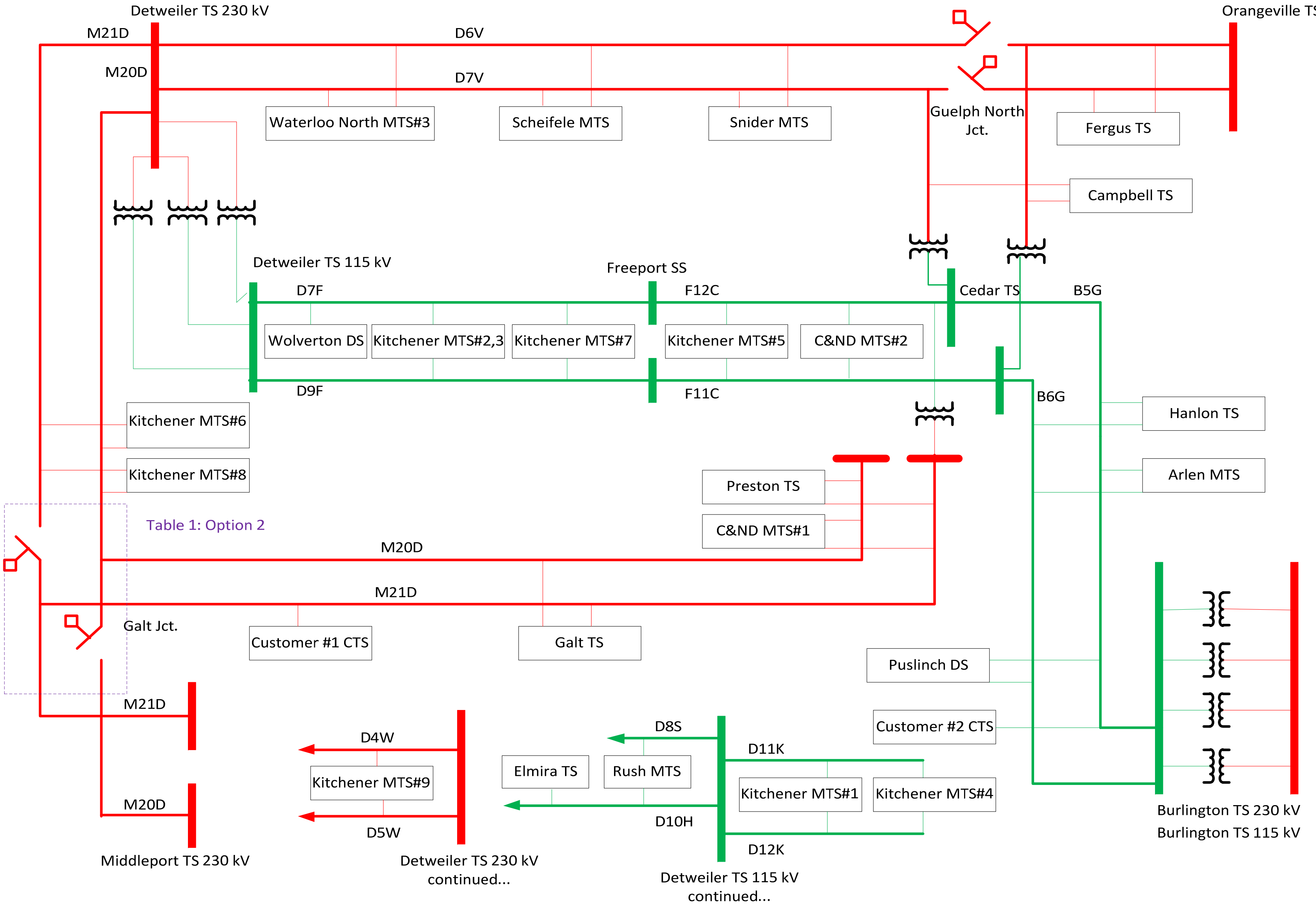
The following recommendations are to address the transmission infrastructure deficiencies within the study period for the KWCG area. These recommendations are:

1. Hydro One Networks to install a set of 230 kV in-line switches onto the main line of circuits M20D and M21D near Galt Junction as soon as possible.
2. Hydro One Networks, the LDCs and the IESO to review the KWCG local area in 2019 with updated KWCG load forecasts to decide on appropriate actions to meet longer-term needs as they emerge.

APPENDIX A: KWCG MAPS



Map 1: Geographical Area of KWCG with Electrical Layout



Map 2: KWCG Electrical Single-Line

APPENDIX B: TRANSMISSION-CONNECTED GENERATION IN THE KWCG AREA

Name	Installed Capacity	Peak Capacity Contribution[5]	Location	Existing or Contracted
Dufferin Wind Farm	97	13.6	Orangeville TS	Existing
Conestoga Wind Farm	67	10.8	D10H	Contracted (future i/s date unknown)

[5] Percentage of installed capacity is 14 % for wind generation

APPENDIX C: KWCG CUSTOMER & LDC LOAD FORECASTS

Table C1: KWCG 2015 RIP Load Forecast*

TS	LDC	Load Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	Planning Demand	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	Planning Demand	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS-Note 1	Cambridge & North Dumfries Hydro	Planning Demand	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Cambridge MTS # 2-Note	Cambridge & North Dumfries Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #6	Kitchener-Wilmot Hydro	Planning Demand	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	Planning Demand	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	Planning Demand	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	Planning Demand	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Kitchener MTS #5	Kitchener-Wilmot Hydro	Planning Demand	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Detweiler TS	Kitchener-Wilmot Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #4	Kitchener-Wilmot Hydro	Planning Demand	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	Planning Demand	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Kitchener MTS #1	Kitchener-Wilmot Hydro	Planning Demand	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Wolverton DS	Hydro One Distribution	Planning Demand	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Fergus TS	Hydro One Distribution	Planning Demand	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Puslinch DS	Hydro One Distribution	Planning Demand	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Cedar TS T1/T2	Guelph Hydro	Planning Demand	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cedar TS T7/T8	Guelph Hydro	Planning Demand	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	Planning Demand	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Arlen MTS	Guelph Hydro	Planning Demand	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	Planning Demand	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	Planning Demand	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo MTS #3	Waterloo North Hydro	Planning Demand	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
Snider MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Bradley MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elmira TS	Waterloo North Hydro	Planning Demand	30.4	25.1	26.0	25.8	27.4	28.1	28.8	29.6	31.3	31.9	33.6
Rush MTS	Waterloo North Hydro	Planning Demand	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS-Note 3	Customer Tx Stations	Planning Demand	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Tx Stations (Assumed values)	Planning Demand	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Planning demand (MW) = ((Gross-CDM) x Extreme Weather Factor) – DG

*Based upon KWCG 2015 IRRP Planning Load Forecast except where otherwise noted.

Note 1: The LDC has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expect to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

Note 2: The LDC has confirmed that additional transformation capacity (Snider/Bradley TS) would not be required until after 2024. The exact location and timing of these TS's have not been determined at this time. The load growth indicated at Snider and Bradley in the forecast can be managed by existing TS's/impact of CDM/DG in the Waterloo Region. LDCs are monitoring the load closely to determine the timing of potential transformation needs. Where possible, these LDCs are exploring opportunities to coordinate use and development of TS facilities in the KWCG Region over the long term. Cambridge #2 is assumed to be supplied off the KWCG 115kV system

Note 3: Slight modification from KWCG 2015 IRRP Planning forecast based on information provided by the transmission-connected customer

Note: Guelph CTS 1 forecast was removed as the LDC confirmed the load was already accounted for within their forecast

APPENDIX D: TECHNICAL RESULTS – LOCAL AREA ANALYSIS

Single element contingencies were considered in order to determine the presence of thermal overload and/or voltage violations.

Table D1: Single Element Contingencies (single zone of protection)

Loss of a Single Circuit (N-1)					
D11K	D12K	D8S	D10H	D7F	D9F
F11C	F12C	B5G	B6G	D4W	D5W
M20D*	M21D**	D6V***	D7V****		
Loss of a Single Autotransformer (N-1)					
Detw. T2	Detw. T3♦	Detw. T4♦♦	Cedar T3♦♦♦	Cedar T4♦♦♦♦	Preston T2**
Middleport T3♦♦♦♦♦		Middleport T6♦♦♦♦♦♦			
Loss of a Single HV Reactive Element (N-1)					
Detweiler 230 kV cap. bank	Middleport 230 kV cap. bank(K1D1)	Orangeville 230 kV cap. bank	Burlington 230 kV cap. bank		
Detweiler 230 kV SVC	Middleport 230 kV cap. bank(K2D2)	Detweiler 115 kV cap bank	Burlington 115 kV cap bank		

*M20D (includes Detweiler T3 and Preston T2 via Preston Special Protection Scheme)

**M21D (includes Preston T2)

***D6V (includes Detweiler T4 and Cedar T3)

****D7V (includes Cedar T4)

♦Detweiler T3 (includes circuit M20D and Preston T2 via Preston SPS)

♦♦Detweiler T4 (includes circuit D6V and Cedar T3)

♦♦♦Cedar T3 (includes circuit D6V and Detweiler T4)

♦♦♦♦Cedar T4 (includes circuit D7V)

♦♦♦♦♦Middleport T3 (includes circuit N580M and V586M due to Line End Open)

♦♦♦♦♦♦Middleport T6 (includes circuit N581M and M585M due to Line End Open)

Results: Thermal Overload and Voltage Violations

Table D3: Thermal Analysis (>100% LTE), year 2025

Element	Contingency	%LTE
All circuits and auto-transfers are within ratings		

Table D4: Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX E: TECHNICAL RESULTS – BULK POWER SYSTEM CONSIDERATIONS

Applicable contingencies were considered on BPS elements to establish their impact on the local area.

Table E1: N-2 Contingencies

Loss of a Double Circuit Line (N-2) emanating from a BPS station		
B22D and B23D	D4W and D5W	M20D and M21D
D6V and D7V	--	--
Breaker Failure (B/F) Contingencies at BPS station (N-2)		
Detweiler TS 230 kV bus	B/F of AL6	Loss of: D6V, Cedar T3, Detw T4, M21D, Preston T2
	B/F of AL7	Loss of: D7V, Cedar T4, M21D, Preston T2
	B/F of L7L20	Loss of: D7V, Cedar T4, M20D, Detw T3, Preston T2
	B/F of HT1A	Loss of: M21D, Preston T2, SVC1
	B/F of ACS21	Loss of : M21D, Preston T2, SC21
	B/F of HL20	Loss of: M20D, Detw T3, D5W, SC22
	B/F of T2SC21	Loss of: Detw T2, SC21
	B/F of HT2	Loss of: Detw T2, SC21, D5W
	B/F of DL22	Loss of: B22D, D6V, Cedar T3, Detw T4
Middleport TS 500 kV bus	Covered under Loss of Middleport T3 and T6 autotransformers for the local area analysis (Appendix D)	
Middleport TS 230 kV bus	There are no B/F conditions that would be critical to the supply to the KWCG area.	

Table E2: N-1-1 Contingencies

Loss of a Critical Element, System Adjustment, Loss of a Critical Element (N-1-1)
Loss of: Detw T4 plus Detw T3 (plus M20D by configuration which also includes the loss of Preston T2 via Preston SPS)
Loss of: Preston T2 plus D7V (plus Cedar T4 by configuration)

Note that during the simulations no System Adjustment was afforded; this is considered a conservative approach.

Results: Thermal Overloads and Voltage Violations

As per Table E3 and E5: Detweiler TS 230/115 kV autotransformer T2 will become overloads when Detweiler TS autotransformer T4 is out-of-service followed by the loss of Detweiler TS autotransformer T3 in conjunction with circuit M20D by configuration. Preston TS autotransformer T2 is also removed from service via the Preston SPS.

Table E3: Thermal Analysis (>95% LTE), year 2016

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	104.4 (74.2% STE*) %

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E4: Voltage Analysis, year 2016

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

Table E5: Thermal Analysis (>95% LTE), year 2025

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	114.2 (81.4%STE*)

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E6 Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX F: LOAD SECURITY ANALYSIS

Load connected to each circuit pair that is lost by configuration following an [N-2] double circuit contingency is:

Table F1: Load Lost Due to Configuration, year 2016

Circuit Pair	MW
M20/21D	420
D6/7V	482
D4/5W	34
D7/9F	131
F11/12C	74
B5/6G	105
D11/12K	98
D8S/D10H	89

Table F2: Load Lost Due to Configuration, year 2025

Circuit Pair	MW
M20/21D	489
D6/7V	571
D4/5W	36
D7/9F	141
F11/12C	78
B5/6G	128
D11/12K	103
D8S/D10H	95[6]

Table F1 illustrates that none of the double circuit contingencies result in more than 482 MW of load lost in year 2016.

Table F2 illustrates that none of the double circuit contingencies result in more than 571 MW of load lost in year 2025.

[6] D8S and D10H emanate out of Detweiler TS as a double circuit line however after ~ 5 km they each become a single circuit 115 kV line. Based on their N/O open points, the loss of the double circuit line within the 5 km span out of Detweiler TS, will results in approximately 95 MW of load lost.

Table F3: Two Elements Out of Service

Loss of a Double Circuit Line		
D7F and D9F	F11C and F12C	B5G and B6G
D4W and D5W	M20D and M21D	D11K and D12K
D6V and D6V		

Loss of Two Autotransformers[7]				
Station	**Detweiler Auto**	**Preston Auto**	**Cedar Auto**	**Burlington Auto**
Detweiler Auto	N/A	Detweiler T3 + Preston T2	Cedar T3 + Detweiler T4	Burlington T6 + Detweiler T3
Preston Auto	Detweiler T3 + Preston T2	N/A	Cedar T4 + Preston T2	Burlington T6 + Preston T2
Cedar Auto	Cedar T3 + Detweiler T4	Cedar T4 + Preston T2	Cedar T3 + Cedar T4	Burlington T6 + Cedar T3
Burlington Auto	Burlington T6 + Detweiler T3	Burlington T6 + Preston T2	Burlington T6 + Cedar T3	N/A

Results: Thermal Overload and Voltage Violations

Table F5: Thermal Analysis (>100% STE), year 2025

Element	Contingency	%STE
All circuits and auto-transfers are within ratings		
Element	**Contingency**	**%LTE**
All circuits and auto-transfers are within ratings		

Table F6: Voltage Analysis (> emergency ratings), year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

[7] For stations that have three or more autotransformers connected in parallel typical operating practice after the loss of one autotransformer is to make load transfers to other interconnected autotransformer station(s) such that the remaining load at the affected station would be at or below the station's reduced Limited Time Rating (LTR). It is assumed the in this case that sufficient time between single autotransformer contingencies is available for such load transfers to be carried out by operator response.

APPENDIX G: LOAD RESTORATION ANALYSIS

Restoration of Load Connected to M20/21D

By year 2025 the total forecasted load connected to circuits M20/21D is 489 MW. Loss of this double circuit line would result in the loss of all 489 MW. In order to restore load to these stations at least one circuit would have to be placed back in service**,** noting that to restore Customer #1 CTS circuit M21D must specifically be placed back in service due to the customer's single-circuit transmission-connection

Based on criteria:

Load Required to be Restored	Duration
239MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Existing infrastructure allows for only the restoration of 100 MW of load in approximately 30 min. This can be accomplished by opening the M20/211D line disconnect switches at Preston TS and back-feed Preston TS T2 230-115 kV autotransformer to supply load at Preston TS only.

Therefore, the existing restoration capability to loads connected to M20/21D does not meet criteria for the duration of the study period.

Restoration of Load Connected to D6/7V

By year 2025 the total forecasted load connected to D6/7V is 571 MW. Loss of this double circuit line would result in the loss of all 571 MW. As part of the Guelph Area Transmission Reinforcement project, two 230 kV in-line switches will be installed in year 2016 on the main line between Detweiler TS and Orangeville TS at Guelph North Junction. To restore load to these stations, the operator will utilize these switches to isolate the problem and return to service the remaining healthy circuit sections. These switches allow for more flexibility to restore load to the affected stations in a timely fashion.

Based on criteria:

Load Required to be Restored	Duration
321MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and

3. the relative distance from the nearest field maintenance centre[8]

the load restoration criterion is substantially met. Therefore, no additional transmission restoration capability is warranted at this time.

<u>Restoration of Load Connected to D4/5W</u>

By year 2025 the total forecasted load connected to D4/5W is 36 MW. Loss of this double circuit line would result in the loss of all 36 MW. To restore load to this station at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
36 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

<u>Restoration of Load Connected to D7/9F</u>

By year 2025 the total forecasted load connected to D7/9F is 141 MW. Loss of this double circuit line would result in the loss of all 141 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
141 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

[8] The KWCG area is considered an urban area and as such, access to transmission facilities, repair materials and personnel in order to make a repair within 8 hours is realistic. A Hydro One field maintenance centre is located in Guelph.

Restoration of Load Connected to F11/12C

By year 2025 the total forecasted load connected to F11/12C is 78 MW. Loss of this double circuit line would result in the loss of all 78 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
78 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to B5/6G

By year 2025 the total forecasted load connected to B5/6G is 128 MW. Loss of this double circuit line would result in the loss of all 128 MW. To restore load to Enbridge Westover CTS's circuit B5G must be placed back in service due to the CTS's single-circuit transmission connection. To restore load at the other stations at least one circuit would to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
128 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D11/12K

The total forecasted load serviced by radial circuits D11/12K will not exceed 103 MW by 2025. Loss of this double circuit line would result in the loss of all 103 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
103 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D8S/D10H

The total forecasted load serviced by these radially operated 115 kV circuits will not exceed approximately 95 MW by year 2025. Loss of this double circuit line would result in loss of all 95MW. To restore Rush MTS either circuit can be placed back into service or the station could possibly be fed via circuit L7S out of Seaforth TS; however to restore Elmira TS circuit D10H must be placed back in service due to Elmira TS's single-circuit transmission-connection.

Based on criteria:

Load Required to be Restored	Duration
95 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

APPENDIX H: SUPPLY TO ELMIRA TS AND RUSH MTS

Study Results:

Table H1: Station Capacity: Summer Ratings and Summer Load Forecast

Station	Transformer Capacity (10-day LTR)	Year 2025 Load Forecast
Rush MTS	69 MVA*	61.3 MW / 69.9 MVA (0.88 pf** at defined meter point, 115 kV side)
Elmira TS	58.5 MVA	33.6 MW / 37.1 MVA*** (0.91 pf at defined meter point, 115 kV side)

*The limiting component is a low voltage cable; when required the limiting component will be modified and the rating to be 75 MVA

** Power factor at the defined meter point improves to 0.92 when 5.4 MVar of installed feeder capacitor banks assumed lumped at the LV bus and results in 66.8 MVA loading

*** A 9.2 MVar @ 27.6 kV shunt capacitor bank is installed at Elmira TS not in-service; when in-service power factor improves and loading through the transformers decrease.

Table H2: Transmission Capacity of circuits D8S and D10H

Year	Contingency	D10H – Detweiler TS x Waterloo Jct.	D8S – Detweiler TS x Leong Jct.
		590 A Continuous *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*	*590 A Continuous* *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*
2016	Pre	287 A	285 A
	Loss of D8S	454 A	--
	Loss of D10H	--	459 A
2025	Pre	319 A /	302 A
	Loss of D8S	511	--
	Loss of D10H	--	500 A

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Table H3: Voltage Profile at Rush MTS and Elmira TS

Year	**Contingency**	**Rush MTS 115 kV D8S**	**Rush MTS 115 kV D10H**	**Rush MTS 13.8 kV**	**Elmira TS 115 kV**	**Elmira TS 27.6 kV**
2016	Pre	122.2	122.2	14.4	120.8	27.2
	Loss of D8S	--	121.8	13.7	120.6	27.1
	Loss of D10H	121.5	--	13.7	--	--
2025	Pre	123.2	123.1	14.2	121.6	27.3
	Loss of D8S	--	122.6	13.6	121.1	27.2
	Loss of D10H	122.4	--	13.6	--	--

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Analysis:

D8S

Circuit D8S has a normally open point at St. Mary's TS separating the circuit from circuit L7S. D8S normally supplies half the load at Rush MTS and half the load at St. Mary's TS. The other half of the load at Rush MTS is normally supplied by circuit D10H and the other half of the load at St. Mary's TS is normally supplied by L7S. Referring to Table H2, for the loss of circuit D10H, circuit D8S has sufficient capacity to supply all load at Rush MTS and St. Mary's TS for year 2025 and beyond.

D10H

Circuit D10H runs between Detweiler TS and Hanover TS and has a normally open point between Elmira TS and Palmerston TS. Elmira TS is normally supplied from Detweiler TS while Palmerston TS is normally supplied from Hanover TS. Referring to Table H2, D10H has sufficient capacity to supply all load at Elmira TS for year 2025 and beyond. When circuit D8S is out of service, D10H has sufficient capacity to supply all load at Elmira TS and Rush MTS (while St. Mary's TS is supplied by circuit L7S).

Rush MTS

Since this station is a Municipal owned station, Waterloo North Hydro is to ensure there is sufficient transformation capacity to accommodate load growth. According to load forecasts and referring to Table H1, over the next 10-years load will fluctuate above and below the year 2025 forecast but will be remain within the station's Limited Time Rating (LTR). Waterloo North Hydro is to inform Hydro One if the connection requires modification and/or if a new station connection is required in order to accommodate load growth. Waterloo North Hydro has already incorporated their future Snider MTS and Bradley MTS into the KWCG regional plan to cater for load growth.

Rush MTS is supplied by two 115 kV circuits, D8S and D10H. Referring to Tables H2 and H3, when one of these circuits is out of service, the voltage profile at Rush MTS is healthy and the other circuit has sufficient capacity to supply all load to Rush MTS.

Elmira TS

According to the forecast and referring to Table H1, transformers at Elmira TS have sufficient capacity for year 2025 loading and beyond.

Elmira TS is supplied by one 115 kV circuit, D10H. Referring to Tables H2 and H3, the voltage profile at Elmira TS is healthy and the circuit has sufficient capacity to supply load to Elmira TS for year 2025 loading and beyond.

When circuit D10H out of Detweiler TS is unavailable, Elmira TS may also be supplied by D10H out of Hanover TS (by closing the normally open point between Palmerston TS and Elmira TS). Assuming Palmerston TS is at its forecasted year 2025 normal weather peak load, approximately 25 MW of load at Elmira TS may be supplied out of Hanover TS. The limiting factor being the 115 kV voltage profile on D10H as Elmira TS is nearly 80 circuit km from Hanover TS.

Metro Toronto

REGIONAL INFRASTRUCTURE PLAN

January 12, 2016

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Enersource Hydro Mississauga
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
PowerStream Inc.
Toronto Hydro-Electric System Limited
Veridian Connections Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE WORKING GROUP IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE METRO TORONTO REGION.

The participants of the RIP Working Group included members from the following organizations:

- Enersource Hydro Mississauga
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- PowerStream Inc.
- Toronto Hydro-Electric System Limited ("THESL")
- Veridian Connections Inc.
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the regional planning process and it follows the completion of the Central Toronto Sub-Region's Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 and the and Metro Toronto Northern Sub-Region's Needs Assessment ("NA") Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for both the Central Toronto Sub-Region and Metro Toronto Northern Sub-Region that make up the Metro Toronto Region.

The Central Toronto IRRP has identified longer term needs beyond 2025. These longer term needs are also reviewed and discussed in this report. However, as the need dates are beyond 2025, adequate time is available to develop a preferred alternative in the next planning cycle expected to be started in 2018.

The major infrastructure investments planned for the Metro Toronto Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost ($M)
1	Manby Autotransformer Overload Protection Scheme	2018	$2
2	Runnymede TS Expansion & Manby x Wiltshire Corridor Upgrade	2019	$90
3	Horner TS Expansion	2020	$53
4	Richview x Manby Corridor Upgrade	2020	$20-40
5	Copeland MTS Phase 2	2020+	$46

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. As mentioned above, the next planning cycle is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE METRO TORONTO REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") on behalf of the Working Group that consists of Hydro One, Enersource Hydro Mississauga, Hydro One Networks Inc. Distribution, the Independent Electricity System Operator ("IESO"), PowerStream Inc., Toronto Hydro-Electric System ("THESL"), and Veridian Connections Inc. in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The Metro Toronto Region is comprised of the City of Toronto. Electrical supply to the Region is provided by thirty five 230kV and 115kV transmission and step-down stations as shown in Figure 1-1. The eastern, northern and western parts of the Region are supplied by eighteen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The summer 2015 area load of the Metro Toronto region was about 4700MW.

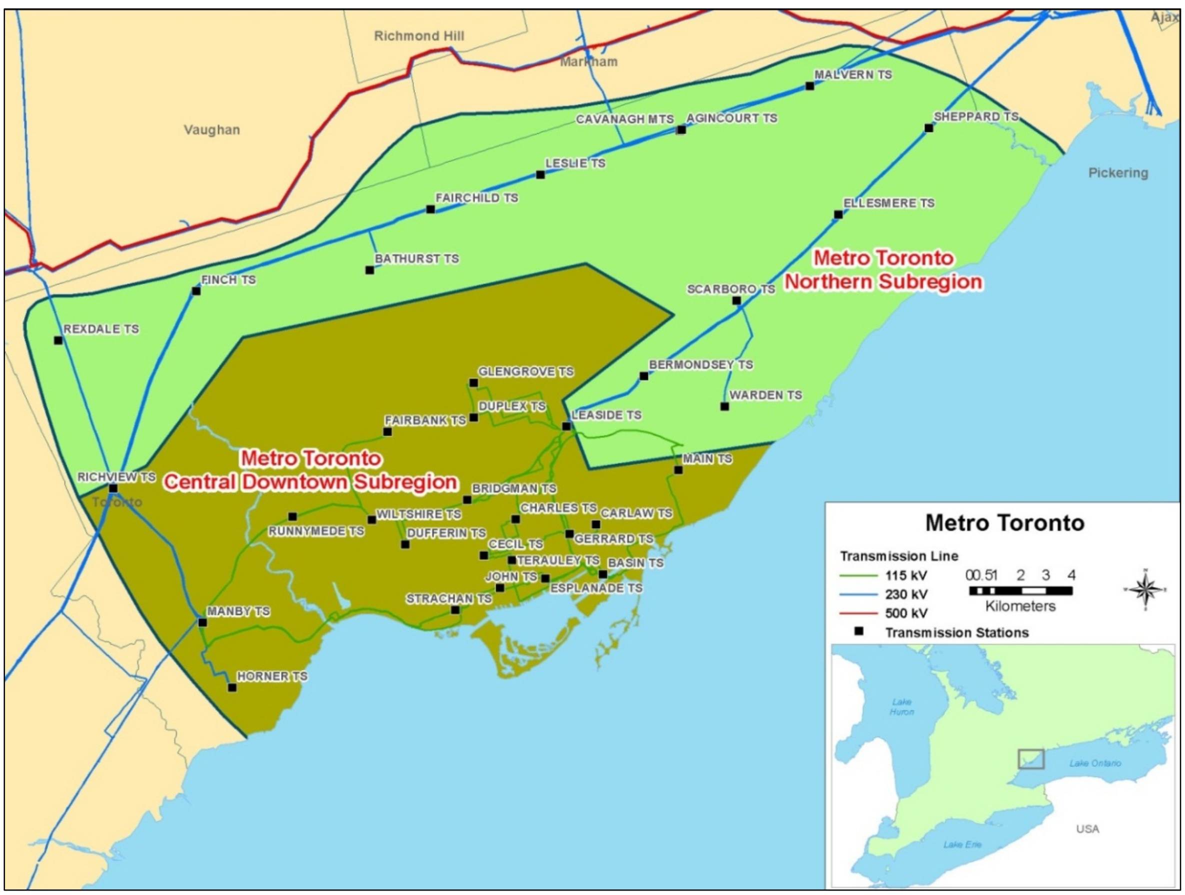

Figure 1-1 Map of Metro Toronto Region

1.1 Scope and Objectives

This RIP report examines the needs in the Metro Toronto Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plan to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Working Group.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process;
- Section 3 describes the region;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast used in this assessment;
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs;
- Section 7 discusses the needs and provides the alternatives and preferred solutions;
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] Also referred to as Needs Screening.

a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee (LAC) in the region or sub-region. For the Metro Toronto Region, community engagement through a formal LAC is on-going.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

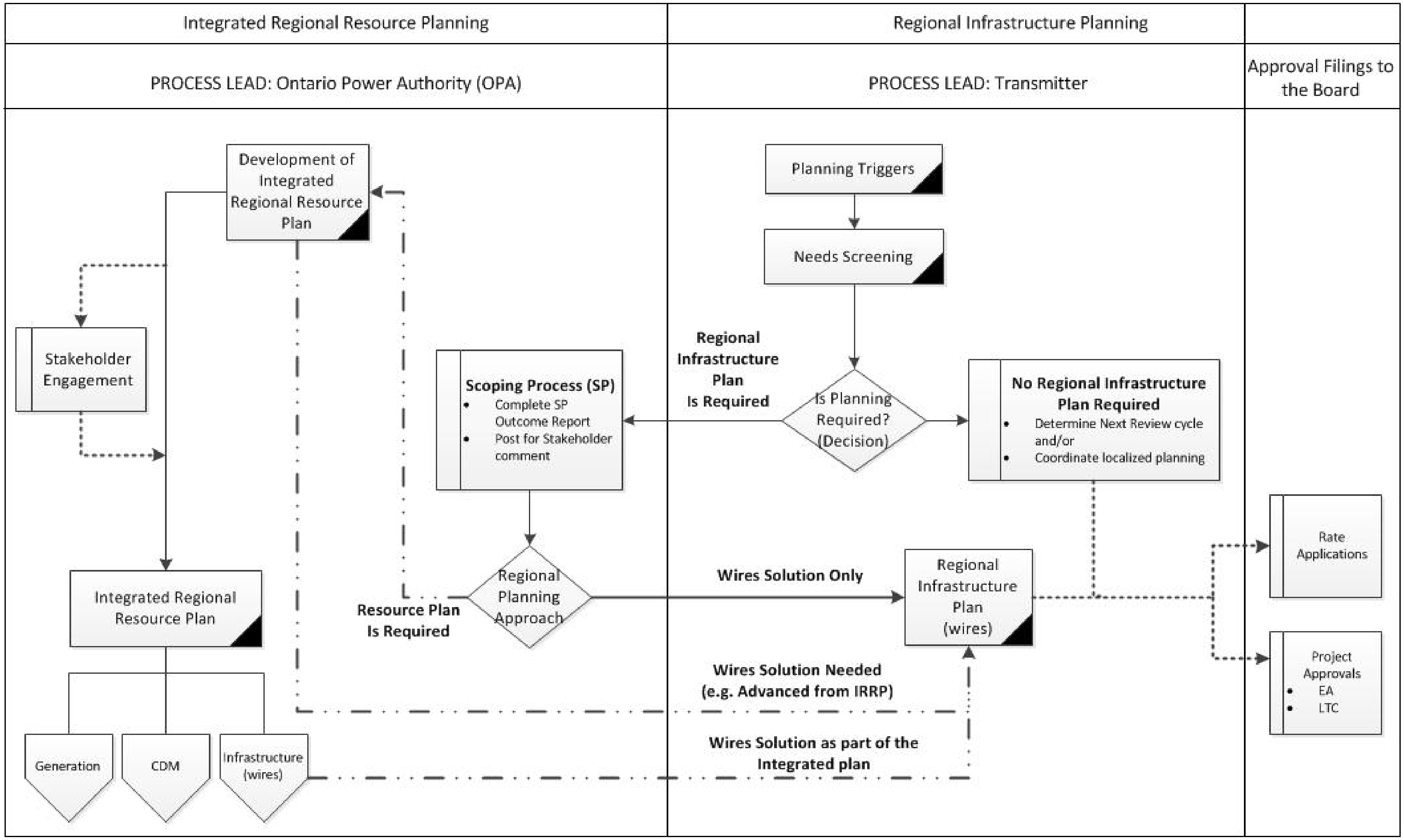

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1) Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

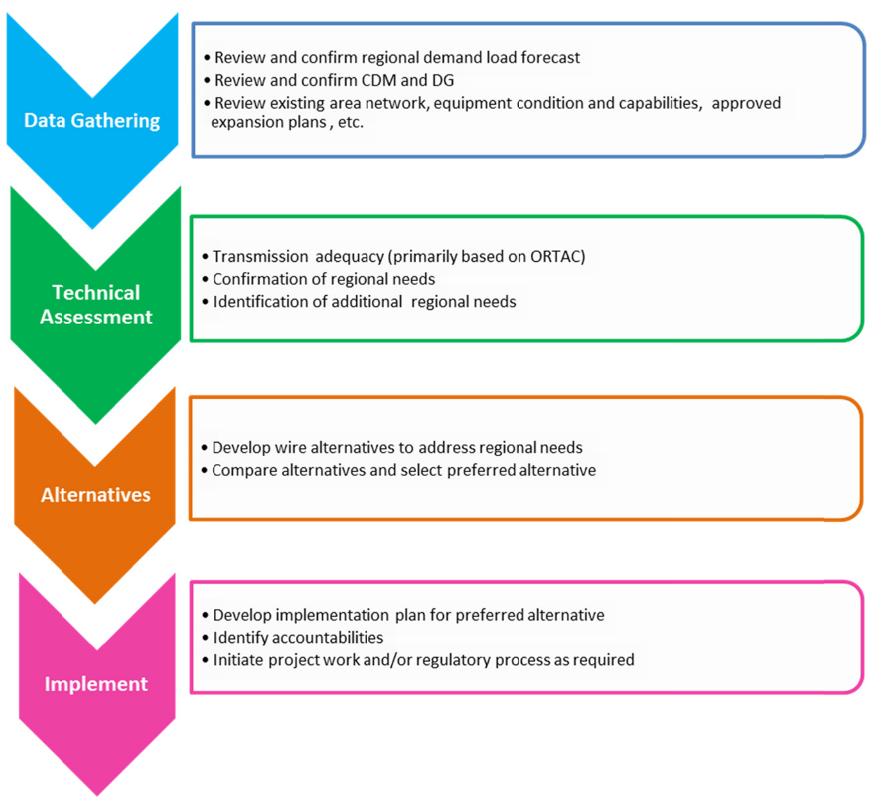

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE METRO TORONTO REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY LAKE ONTARIO ON THE SOUTH, STEELES AVENUE ON THE NORTH, HIGHWAY 427 ON THE WEST AND REGIONAL ROAD 30 ON THE EAST. IT CONSISTS OF THE CITY OF TORONTO, WHICH IS THE LARGEST CITY IN CANADA AND THE FOURTH LARGEST IN NORTH AMERICA.

Bulk electrical supply to the Metro Toronto Region is provided through three 500/230 kV transformers stations - Claireville TS, Cherrywood TS and Parkway TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. Local generation in the area consists of the 550 MW Portlands Energy Centre located near downtown area and connected to the 115 kV network at Hearn Switching Station. The Metro Toronto Region 2015 peak summer demand was about 4700MW which represents about 20% of the gross electrical demand in the province.

Toronto Hydro-Electric System Limited ("THESL") is the Local Distribution Company ("LDC") that serves the electricity demands for the city of Toronto. Other LDCs supplied from electrical facilities in the Metro Toronto Region are Hydro One Networks Inc. Distribution, PowerStream Inc., Veridian Connections Inc., and Enersource Hydro Mississauga. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Central Toronto Area which included the 115kV network and the 230kV facilities in the western part of Region. The June 2014 Metro Toronto Northern Sub-Region Needs Assessment report, prepared by Hydro One, considered the remainder of the Metro Toronto region. A map and a single line diagram showing the electrical facilities of the Metro Toronto Region, consisting of the two sub-regions, is shown in Figure 3-1 and Figure 3-2 respectively. Please note that the facilities shown include the new Leaside TS to Bridgman TS 115kV circuit L18W and the new Copeland MTS. The L18W circuit is being built as part of the Midtown Transmission Reinforcement Project and Copeland MTS is a new THESL owned transformer station to serve the downtown area. Work on these projects is in the advanced stage and both are expected to come into service in 2016.

3.1 Central Toronto Sub-Region

The Central Toronto Sub-Region includes the area extending northward from Lake Ontario to roughly Highway 401, westward to Highway 427 and Etobicoke Creek, and eastward to Victoria Park Avenue.

The Central Toronto Sub-Region was identified as a "transitional" region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

The Central Toronto Sub-region is further subdivided into two areas:

- The Richview Manby 230kV area: This includes the former borough of Etobicoke and is served by the Richview TS to Manby TS 230kV circuits. The area has two 230/27.6kV step-down transformer stations. The coincident peak summer 2015 area load was about 320 MW. The Richview TS to Manby 230kV circuits together with the Richview TS to Cooksville TS circuit R24C supply a number of stations in the GTA West Southern Sub-Region. These stations while outside the Metro Toronto Region have therefore been included in Figure 3-2.

- The Central 115kV Area: The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS), fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The area includes the downtown core including the financial, entertainment and educational districts. The 2015 summer coincident area load was about 1900MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Metro Toronto Northern Sub-Region

The Metro Toronto Northern Sub-Region comprises the remainder of the Metro Toronto region. It includes the area roughly bordered geographically by Highway 401 on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east in addition to the area east of the Don Valley Parkway and north of O'Connor Dr.

Electrical supply to the Metro Toronto Northern Sub-Region is provided through 230 kV transmission lines and step-down transformation facilities. Supply to this sub-region is provided from a 230 kV transmission system consisting of the Richview TS to Parkway TS, the Richview TS to Cherrywood TS, the Richview TS to Claireville TS, as well as the Cherrywood TS to Leaside TS 230kV transmission system. The area is served primarily at 27.6kV by fifteen step-down transformer stations with a pocket of 13.8kV load supplied from Leaside TS and Leslie TS. The 2015 summer coincident area load was about 2500 MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

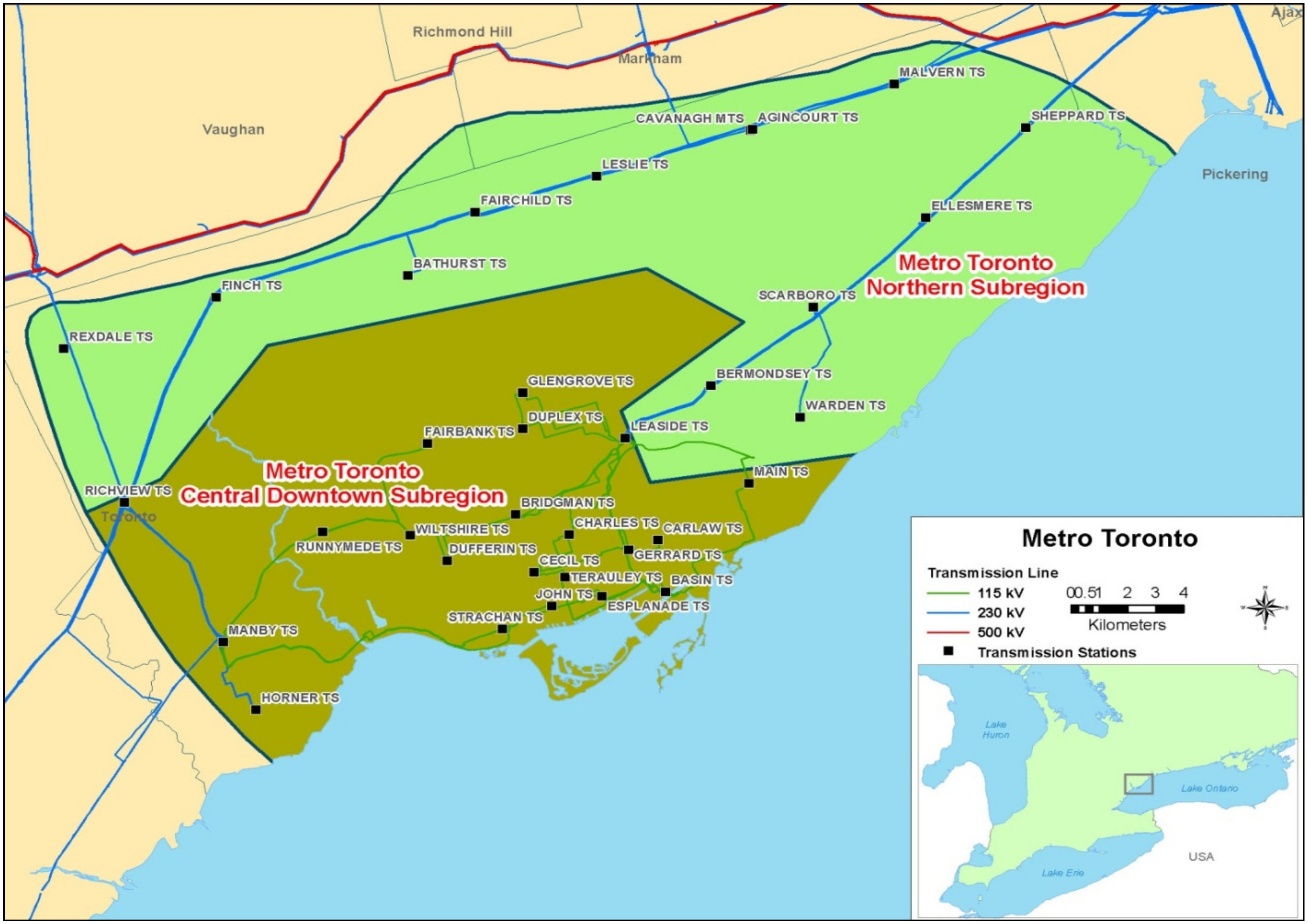

Figure 3-1 Metro Toronto Region – Supply Areas

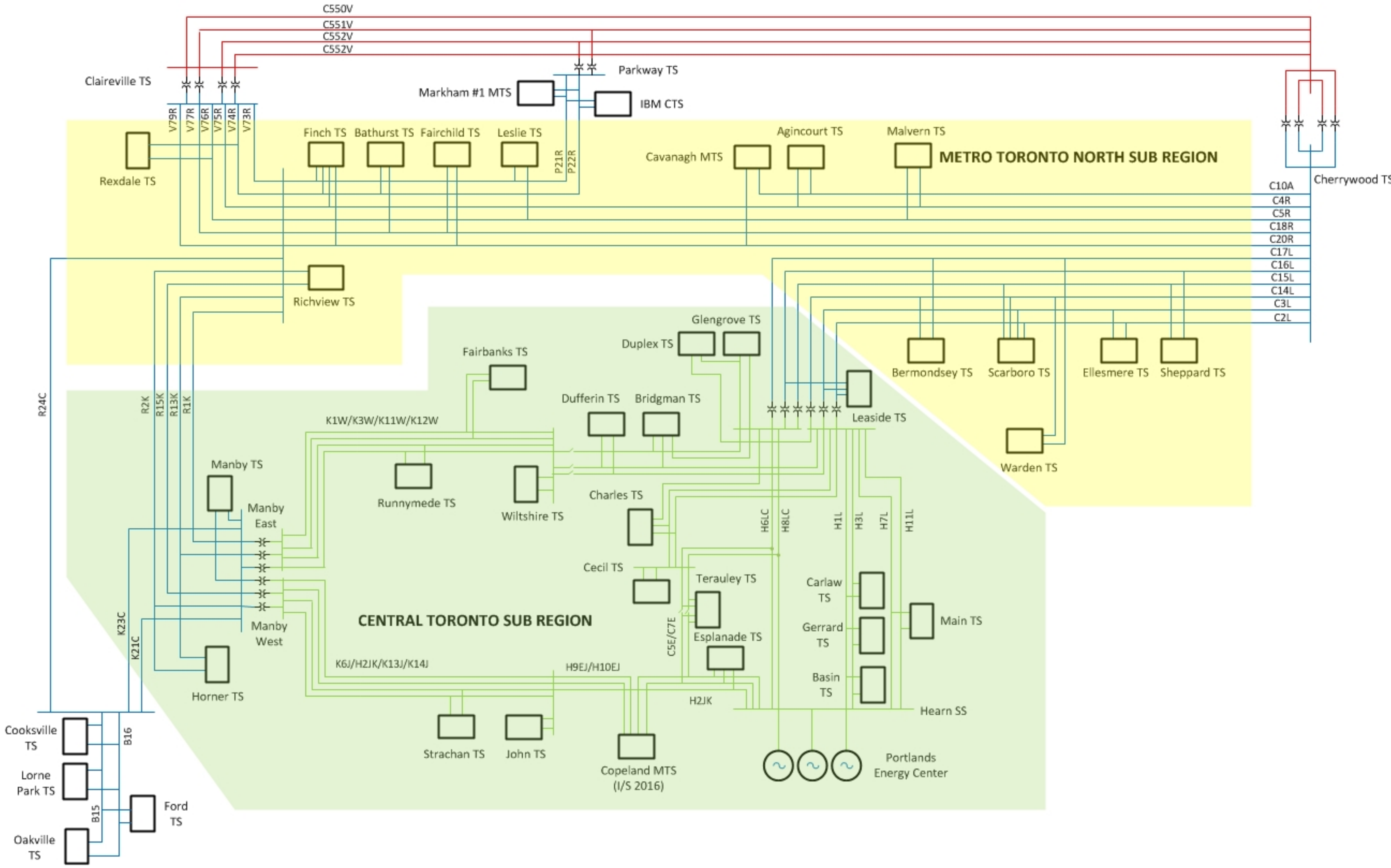

Figure 3-2 Metro Toronto Region – Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED AND/OR UNDERWAY OVER THE LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE METRO TORONTO REGION IN GENERAL AND THE TORONTO 115 KV NETWORK IN PARTICULAR.

These projects together with the new 550 MW Portlands Energy Centre that went into service in 2009 have ensured that the City continues to receive adequate and reliable supply. A brief listing of these projects is given below:

- Parkway 500/230 kV TS (2005) – built to provide adequate 500/230 kV transformation capacity following the retirement of Lakeview GS. The station while just outside the Metro Toronto Region is a key contributor in ensuring supply adequacy to the Region.

- John TS to Esplanade TS underground cable circuits (2008) – built to provide transfer capability between the Leaside TS and the Manby TS 115 kV areas.

- Incorporation of the 550 MW Portlands Energy Centre (2009) – covered modification to the Hearn 115kV switchyard to connect the new generation.

- 115 kV Switchyard Work at Hearn SS, Leaside TS & Manby TS (2013 & 2014) – covered replacement of the aging 115 kV switchyard at Hearn SS with a new GIS switchyard and replacement of all 115 kV breakers at Leaside TS and Manby TS.

- Manby 230 kV Reconfiguration (2014) – re-tapped Horner TS from the circuit R15K to R13K at Manby TS to balance / improve the distribution of loading on the 230 kV Richview TS to Manby TS system.

- Lakeshore Cable Refurbishment project (2015) – covered replacement of the aging K6J/H2JK 115 kV circuits between Riverside Jct. and Strachan TS.

- Midtown Transmission Reinforcement Project (expected completion by 2016) – covered replacement of the aging L14W underground cable and building an additional fourth 115 kV circuit between Leaside TS and Bridgman TS.

- Clare R. Copeland 115kV switching station (expected completion by 2016) – built to connect a new THESL owned 115/13.8 kV step-down transformer station in the downtown district.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Metro Toronto Region is forecast to increase at an average rate of approximately 0.9% annually up to 2020, at 0.67% between 2020 and 2025 and at 0.61% beyond 2025. The growth rate varies across the region – from about 0.35% in the Northern Sub-Region to 1.07% in the City's downtown area over the 20 years.

Figure 5-1 shows the Metro Toronto Region's planning load forecast (summer net, non-coincident and regional-coincident extreme weather peak) under the IRRP high growth scenario. The regional-coincident (at the same time) forecast represents the total peak load of the 35 step-down transformer stations in the Metro Toronto. The coincident regional peak load is forecast to increase from 5176 MW in 2015 to 6196 MW by 2035.

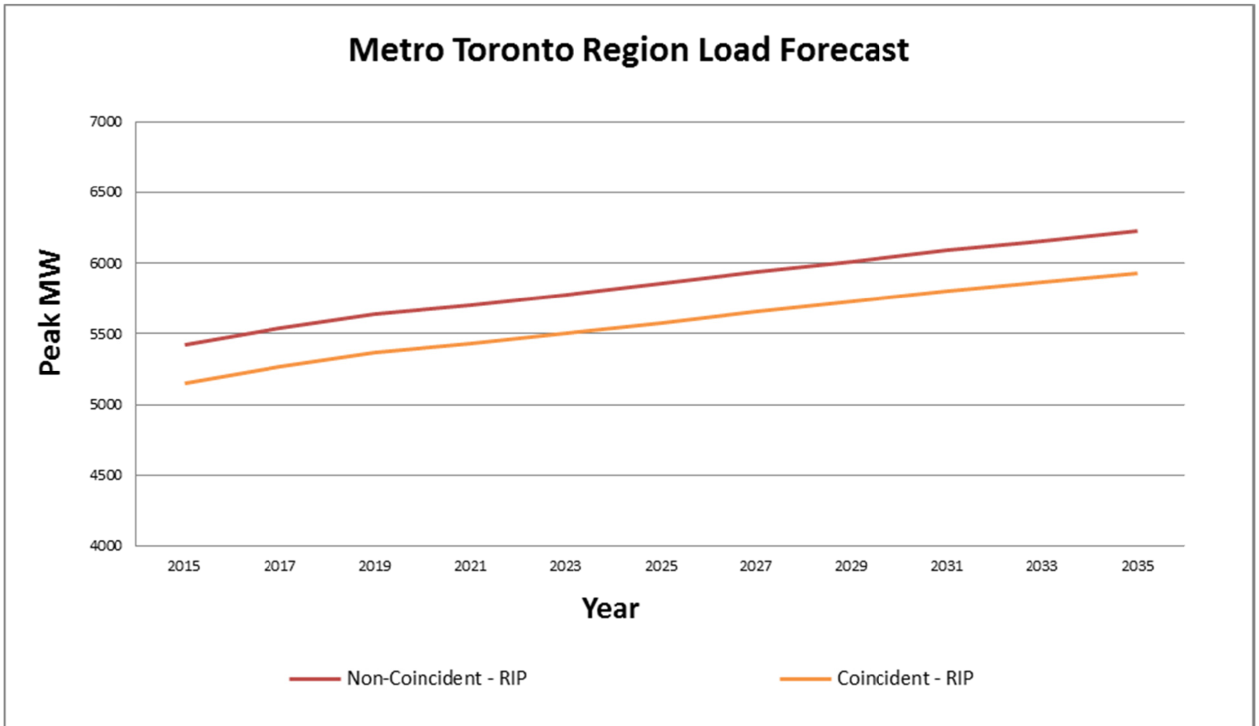

Figure 5-1 Metro Toronto Region Summer Extreme Weather Peak Forecast

The coincident and non-coincident extreme weather peak load forecast for the individual stations in the Metro Toronto Region is given in Appendix D. The coincident forecast represents the sum of the area stations peak load at the time of Metro Toronto Region peak demand and represents loads that would be seen by transmission lines and autotransformer stations and is used to determine the need for additional line and auto-transformation capacity. The non-coincident forecast represents the sum of the individual stations peak load and is used to determine the need for station capacity.

The individual station forecasts were developed by projecting 2015 summer peak loads, corrected for extreme weather, using the area stations growth rates as per the 2015 IESO's IRRP study (High Demand Scenario) for the Central Toronto Sub-Region [1] and as per the 2014 Hydro One's Need Assessment study [2] for the Metro Toronto Northern Sub-Region. The growth rates from [1] only account for existing Distributed Generation ("DG"), and do not include any new CDM and DG. The growth rates from [2] are the net growth rates seen by station equipment and account for CDM measures and connected DG. Details on the CDM and connected DG are provided in [1] and [2] and are not repeated here.

Impact of Metrolinx Go Transit Electrification

In June 2015, Metrolinx advised Hydro One that they are planning to proceed with the electrification of the Go transit rail system. This information was provided after the IRRP was completed in April 2015. Under their plan three Traction Power Stations (TPS) are proposed to be built in the Metro Toronto Region. These stations are as follows:

- Mimico TPS – For the Lakeshore West Go Transit Line (2020)
- Cityview TPS – For the Pearson Airport and Kitchener Go Transit lines (2020)
- Warden TPS – For the Lakeshore East Go Transit Line (2020)

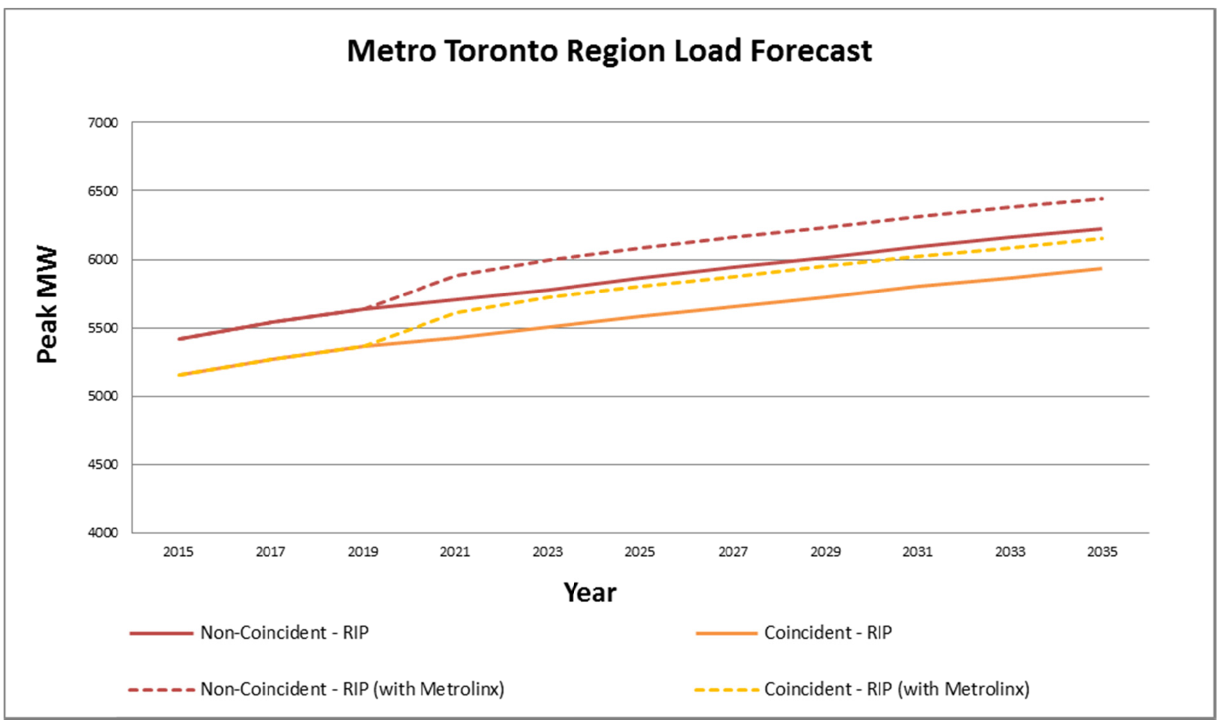

Figure 5-2 Effect of Metrolinx Electrification on the Metro Toronto Region Summer Peak Load

The impact of the Metrolinx load on the regional forecast is shown in Figure 5-2. Each of the three Metro area stations is expected to have an initial load of 40MW increasing to 80MW in 4 years. The net result is to increase the Region peak load by 240MW.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP Assessments is 2015-2035.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).
- For THESL 13.8kV stations, an additional 95% factor is applied to the normal planning supply capacity in this study. This is to reflect the fact that all the capacity cannot be effectively utilized due to the large relative size of the individual customer loads.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE METRO TORONTO REGION OVER THE 2015-2035 PERIOD. IT ASSUMES THAT ALL PROJECTS CURRENTLY UNDER WAY ARE IN SERVICE.

Within the current regional planning cycle two regional assessments have been conducted for the Metro Toronto Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's Central Toronto Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – Metro Toronto – Northern Sub-Region – June 11, 2014[2]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demands. These regional needs are summarized in Table 6-1 and include needs for which work is already underway and/or being addressed by a LP study. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the Metro Toronto Region was also carried out as part of the RIP report using the latest Regional Forecast based on the IRRP high load growth scenario and as given in Section 5. The impact of Metrolinx Electrification on the regional infrastructure has been included.

For cases where a need was identified in the near or mid-term by the high growth scenario, a sensitivity analysis was done using the IRRP low growth scenario to get a range on the need date. Sections 6.1 to 6.2 present the results of this review. Additional needs identified as a result of the review are also listed in Table 6-1.

Table 6-1 Needs identified in Previous Stages of the Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	West Toronto (Runnymede TS & Fairbank TS)	Today
	7.2	Southwest Toronto (Manby TS & Horner TS)	2020-2027
	7.3	Downtown District (JETC[1] Area)	2020+[2]
Transmission Line Capacity	7.4	230 kV Richview TS to Manby TS Corridor	2020-2023
	7.5	Circuit C10A (Duffin Jct. to Agincourt Jct.)	Completed
Supply Security, Reliability and Restoration	7.6	Breaker failure contingencies at Manby W and Manby E TS	2018/2021
	7.7	Breaker failure contingency at Leaside TS	Today
	7.8	Double circuit contingencies C2L/C3L or C16L/C17L (Cherrywood TS to Leaside TS)	2021
	7.9	Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)	Today
Long-Term	7.10	115 kV Manby West To Riverside Jct. Lines	2035+
		230/115 kV Manby TS transformer capacity	2035+
		230/115 kV Leaside TS transformer capacity	2026+
Additional Long-Term Need Identified in RIP	7.10	Leaside TS x Wiltshire TS circuits	2034

[1] JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.
[2] The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

6.1 Metro Toronto Northern Sub-Region

6.1.1 230kV Transmission Facilities

The Northern 230kV facilities consist of the following 230kV transmission circuits (Please refer to Figure 3-2):

a) Claireville TS to Richview TS 230kV circuits: V72R, V73R, V74R, V76R, V77R and V79R.
b) Cherrywood TS to Richview TS 230kV circuits: C4R, C5R, C18R and C20R.
c) Parkway TS to Richview 230kV circuits: P21R and P22R
d) Cherrywood TS to Agincourt TS 230kV circuit C10A.
e) Cherrywood TS to Leaside TS 230kV circuits: C2L, C3L C14L, C15L, C16L and C17L.

The Claireville TS to Richview TS circuits, the Cherrywood TS to Richview TS circuits and the Parkway TS circuits to Richview TS circuits carry bulk transmission flows as well as serve local area station loads within the Sub-Region. These circuits are adequate over the study period.

The Cherrywood TS to Agincourt TS circuit C10A is a radial circuit that supplies Agincourt TS and Cavanagh TS. The Need Assessment for the Metro Toronto Northern Sub-Region had identified that line capacity was restricted due to inadequate clearance from underbuilt street lighting and distribution line. Field surveys carried out by Hydro One have confirmed that the limiting underbuilds have been removed. The circuit is adequate over the study period.

The Cherrywood TS to Leaside TS 230kV circuits supply the Leaside TS 230/115kV autotransformers as well as serve local area load. Loading on these circuits is adequate over the study period.

6.1.2 Step-Down Transformer Station Facilities

The Sub-Region has the following step down transformer stations:

Agincourt TS	Leaside TS
Bathurst TS	Leslie TS
Bermondsey TS	Malvern TS
Cavanagh MTS	Rexdale TS
Ellesmere TS	Scarboro TS
Fairchild TS	Sheppard TS
Finch TS	Warden TS

The Metro Toronto Northern Sub-Region Needs Assessment Report had identified that the gross load was approaching station capacity at Cavanagh MTS and the Leslie TS (T1/T2, 27.6kV windings) and the Sheppard TS (T3/T4) DESN units. No action was recommended as the net load after considering the CDM and DG program is within ratings. The RIP report has reviewed the station loading and confirms that station capacity is adequate over the study period. However, the station loads will be monitored to ensure facility ratings are not exceeded.

6.2 Central Toronto Sub-Region

6.2.1 230kV Transmission Facilities

The 230kV transmission facilities in the Central Toronto Sub-Region are as follows (Please refer to Figure 3-2):

a) Richview TS x Manby TS 230kV circuits: R1K, R2K, R13K and R15K
b) Cooksville TS x Manby TS 230kV circuits: K21C/K23C
c) Manby TS 230/115kV autotransformers
d) Leaside TS 230kV/115kV autotransformers

The Richview TS to Manby TS circuits and the Cooksville TS to Manby TS circuits supply the Manby 230/115kV autotransformer station as well as Horner TS. Please note that the K21C and K23C circuits connect back to Richview TS through Cooksville TS and 230kV circuit R24C.

Table 6-2 summarizes the result of adequacy studies and gives the need date for transmission reinforcement for each of the above facilities.

Table 6-2 Adequacy of 230kV Transmission Facilities

Facilities	2015 MW Load(1)	MW Load Meeting Capability (LMC)	Limiting Contingency	Need Date
Richview x Manby 230kV Corridor	1456	1540	R2K	2020-2023(2)
Manby E. 230/115kV autos	330	560	T2	2035+
Manby W. 230/115kV autos	397	612	T9	2035+
Leaside 230/115kV autos + Portlands GS(1)	1340	1525-1915(3)	None	2026+(4)

(1) The loads shown have been adjusted for extreme weather.
(2) The 2020 and 2023 need dates correspond to the high growth and low growth rate scenarios without considering Metrolinx Mimico TPS. Assuming Metrolinx Mimico TPS comes into service in 2020, the need date will become 2020 under both scenarios.
(3) The Leaside 115kV area is supplied by the Leaside TS 230/115kV autotransformers and the 550MW Portlands GS. Load Meeting capability is dependent on the generation from Portlands GS which backs up the flow through the Leaside autotransformers. The 1525MW LMC assumes only 160MW generation at Portland GS while the 1915MW LMC assumes the full 550MW generation at Portland GS.
(4) The need date is based on the 1525MW LMC which assumes that two of the three units are out at Portlands GS and total plant generation is 160MW.

6.2.2 115kV Transmission Facilities

The 115kV facilities in the Metro Toronto Region (see Figure 3-2) can be divided into five main corridors:

1. Manby TS East x Wiltshire TS – Four circuits K1W, K3W, K11, K12W. Forecast loading can exceed corridor rating under certain conditions. More details are provided in Section 7.1.2.
2. Manby TS West x John TS – Four circuits H2JK, K6J, K13J and K14J. These circuits are adequate over the study period.
3. Leaside TS x Hearn TS – Six circuits H6LC, H8LC, H1L, H3L, H7L and H11L. These circuits are expected to be adequate over the study period. .
4. Leaside TS x Cecil TS – Three circuits L4C, L9C, and L12C. These are expected to be adequate over the study period.
5. Leaside TS x Wiltshire TS – Four circuits L13W/L14W/L15/L18W. The L18W circuit is expected to go into service in summer 2016. Loading will exceed corridor rating by 2034 for loss of the L18W circuit. More details are provided in Section 7.10.4.

The loading on the limiting sections is summarized in Table 6-3.

Table 6-3 Overloaded Sections of 115kV circuits

Facilities	2015 MW Load	MW Load Meeting Capability	Limiting Contingency	Need Date
Manby TS x Wiltshire TS 115kV Corridor	330	348/410(1)	K11W	2019-2023(1)
Leaside TS x Wiltshire TS	310	350	L18W	2034

(1) The Manby x Wiltshire corridor provides emergency backup for Dufferin TS load under Leaside area contingencies. Assuming that a 100MW of back up capability is provided, the maximum load that can be supplied in the Fairbanks/Runnymede area is 348MW and the need date for upgrading the corridor is 2019. If 75MW of back up capability is required, the need date will become 2023. However, if back up capability during peak is not considered, maximum load meeting capability is 410MW. The need in this case would be beyond 2035.

6.2.3 Step-Down Transformer Facilities

There are a total of 20 step-down transformers stations in the Central Toronto Sub Region.as follows:

Basin TS	Esplanade TS	Fairbank TS
Bridgman TS	Gerrard TS	Copeland MTS
Carlaw TS	Glengrove TS	John TS
Cecil TS	Main TS	Strachan TS
Charles TS	Terauley TS	Horner TS
Dufferin TS	Wiltshire TS	Manby TS
Duplex TS	Runnymede TS	

The stations non-coincident loads are given in Appendix D Table D-1. The areas and the stations requiring relief are given in Table 6-4.

Table 6-4 Adequacy of Step-Down Transformer Stations - Areas Requiring Relief

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
West Toronto: Fairbanks TS and Runnymede TS	285	291	Now
Southwest Toronto : Manby TS and Horner TS area	400	376	2020-2027 (1)
Downtown Toronto: John TS, Esplanade TS, Terauley TS and Copeland MTS (JETC)	739	632	2020+ (2)

(1) The need dates are based on high and low demand growth rates scenario

(2) The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

7. REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE METRO TORONTO REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP FOR THE CENTRAL TORONTO SUB-REGION [1] AND THE NA FOR THE METRO TORONTO NORTHERN SUB-REGION [2] AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 West Toronto Area

7.1.1 Station Capacity - Runnymede TS & Fairbank TS

Runnymede TS and Fairbank TS are 115/27.6 kV transformer stations that supply the load demand in the west end of Toronto. The two stations are connected to the 115 kV Manby East transmission system and have been operating at or near their capacity limits for the last five years. THESL has managed growth by transferring loads to adjacent area stations.

The area 2015 extreme weather peak load was 291 MW and exceeded the stations capacity of 285MW. The area is experiencing some re-development and the proposed Eglinton Crosstown Light Railway Transit (“LRT”) project by MetroLinx will add an additional 14 MW of load to Runnymede TS in 2021. Additional step down transformation capacity is required now to provide relief and be able to meet the forecast load demand.

7.1.2 Line Capacity - Manby TS x Wiltshire TS 115kV circuits

The Manby TS x Wiltshire TS four circuit 115kV tower line carries circuits K1W, K3W, K11W and K12W. These circuits supply Fairbanks TS, Runnymede TS and well as Wiltshire TS. Under Leaside area outage conditions, these circuits are also used to pick up all or parts of Dufferin TS and/or Bridgman TS loads. The total corridor capability is dependent on the Fairbanks TS and Runnymede TS load and the load picked up and is given in table below:

Table 7-1 Manby x Wiltshire Corridor Capability

Year	Fairbanks TS, Runnymede TS, and Wiltshire TS Load Forecast (MW)	Amount of Dufferin TS and Bridgman TS Load that can be picked up (MW)	Total Corridor Capability (MW)
2015	330	120	450
2019	349	97	446
2023	375	68	443
2027	390	46	436
2031	399	25	424
2035	406	10	416

The timing of the Manby TS x Wiltshire TS circuits upgrade is dependent on the backup capability desired. If backup capability is not considered, the upgrade can be deferred to beyond 2035. However, if at least 70MW of back up capability - equal to about half of Dufferin TS load - is deemed appropriate, the upgrade would be deferred to about 2023.

Figure 7-1 West Toronto Area - Fairbank TS and Runnymede TS

7.1.3 Recommended Plan and Current Status

The Working Group has considered and reviewed several options to provide additional transformation capacity in West Toronto area as part of the Central Toronto IRRP. Based upon the review, and consistent with the IRRP Working Group recommendation is to expand Runnymede TS by adding two 115/27.6 kV 50/83 MVA transformers and a 27.6kV switchyard with six feeders. This work is required to be completed as early as possible.

The Working Group also recommends that the Manby TS to Wiltshire TS tower line carrying circuits K1W/K3W/K11W/K12W be also upgraded at the same time. This option would maintain the load transfer capability between Leaside TS and the Manby TS under emergency or outage conditions in addition to supplying future load growth in the West Toronto Area.

The estimated total cost of the work is approximately $90 M, which includes $34 M for the station work at Runnymede TS, $16 M for the upgrade of four 9.5 km long circuits between Manby TS and Wiltshire TS and $40 M for distribution facilities by THESL. The transmission cost of $50M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals. The estimate is expected to be completed by the end of Q2 2016. It will also confirm if the targeted in-service date of May 2019 for this project is achievable. A Section 92 application will be submitted in 2016.

7.2 Southwest Toronto Area

7.2.1 Station Capacity – Southwest Toronto (Manby TS & Horner TS)

Manby TS and Horner TS are two 230/27.6 kV transformer stations supplying the load demand in the southwest end of Toronto (see Figure 7-2). Based on the current RIP forecast the 400MW combined station capacity of the stations is forecast to be exceeded by summer 2020. Additional step down transformation is required to provide relief.

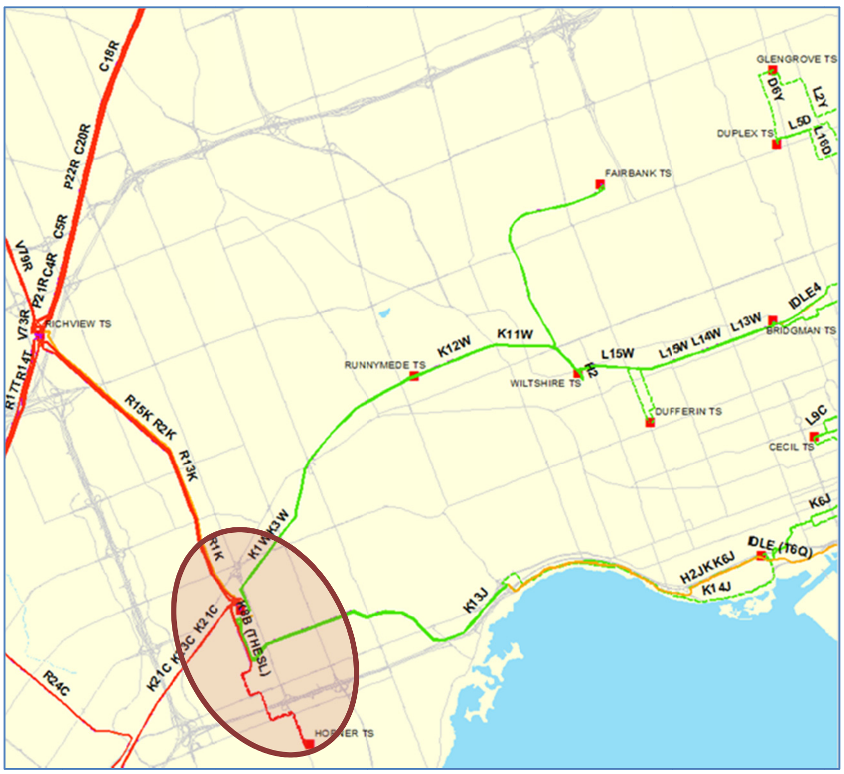

Figure 7-2 Horner TS and Manby TS Supply Area

7.2.2 Recommended Plan and Current Status.

To address the need for additional step down transformation capacity in the Southwest Toronto area, the Working Group's recommended building a second 230/27.6 kV DESN at the existing Horner TS site. Two 75/125MVA transformers will be installed at the station along with a new 27.6kV switchyard. Load transfer out of Manby TS to Horner TS is required to relieve Manby TS as the loading at that station exceeds its capacity. New distribution feeder ties are required to be built between Manby TS and Horner TS by THESL.

The estimated total cost of the work is about $53M, which includes $34 M for the station work at Horner TS and $19M for THESL distribution facilities. The transmission cost of $34M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals at the request of THESL. The current in-service date for the project is expected to be May 2020.

7.3 Downtown District

7.3.1 Station Capacity – JETC[2] Area

The Toronto Downtown Core area is mainly supplied by the three existing 115/13.8 kV stations: John TS, Esplanade TS, and Terauley TS. John TS is connected to the Manby West system while Esplanade TS and Terauley TS are fed from the 115 kV Leaside / Hearn system. (see Figure 7-3)

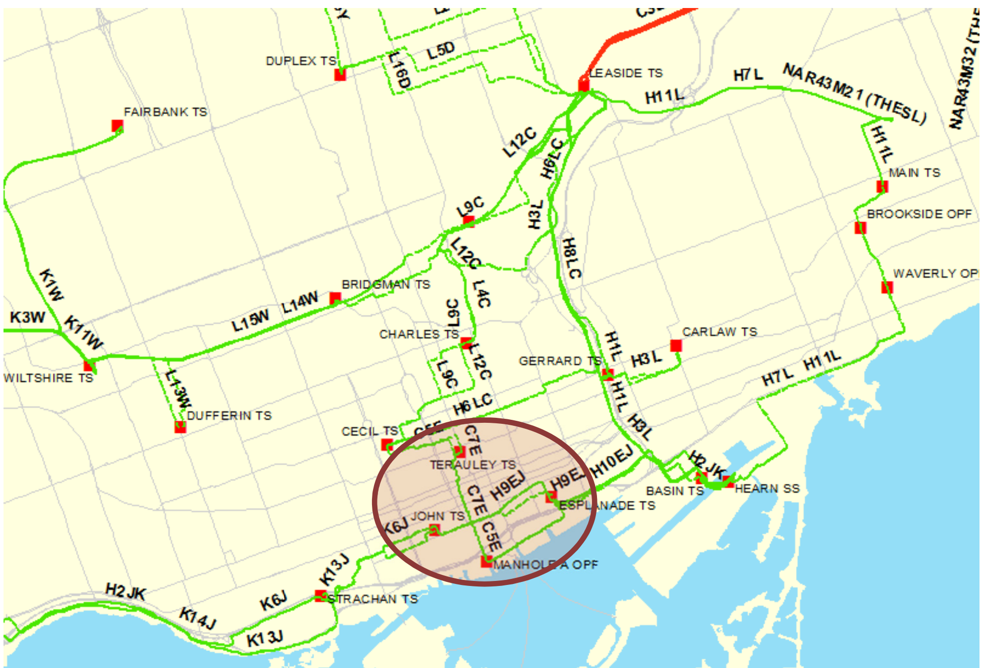

Figure 7-3 Toronto Downtown Supply Area

John TS was built in the 1950's and the THESL switchgear at the station is approaching end of life. THESL is building a new 115/13.8kV owned transformer station, Copeland MTS in the Downtown

[2] JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.

District near John TS with normal supplied from the 115 kV Manby West system. The station first phase capacity will be around 130 MVA and it is expected to be in service in 2016. Copeland MTS will provide a new source of supply to the area customers and facilitate the replacement of end of life switchgear at John TS.

With the new Copeland MTS in-service in 2016, adequate transformation capacity will be available in the Downtown District till 2027. However, most of this capacity will be at John TS as 13.8kV buses at both Terauley TS and Esplanade TS are at or approaching capacity limits. THESL anticipates that the need for new transformation facility is more advanced due to limited spare feeder positions available at John TS for new customer connection and load transfer required to facilitate the refurbishment work at John TS. At the current pace of development in these areas, both bus and feeder position in the Downtown Core area are expected to be at or near capacity within five to ten years[3]. Specific issues identified by THESL Hydro are as follows:

- By 2019 THESL forecasts that two busses will be overloaded (ie. loaded beyond 10 Day LTR) at George and Duke MS and two busses overloaded at John/Windsor TS.
- By 2025 THESL forecasts that one bus will be overloaded at Copeland TS, two busses overloaded at George and Duke MS and three busses overloaded at John/Windsor TS.
- At John/Windsor TS, four out of six busses have no spare feeder positions to connect new customers. One bus has a single spare feeder position and one bus has two spare feeder positions.
- At George and Duke MS, one bus has no spare feeder positions and one bus has six spare feeder positions.
- At Esplanade TS, there is only one bus with three spare feeder positions.
- Once in service, Copeland TS is forecasted to have six and three spare positions on each its two busses, respectively.

7.3.2 Recommended Plan and Current Status

Based on the current information, the need to relieve the stations in Downtown District is expected to be beyond 2020. However, the need date may get delayed or brought forward if the load growth in this area is slower or faster than currently anticipated. The Working Group recommends that this need and timing should be further refined by THESL through their distribution planning process and included in updates to the IRRP and RIP. The uptake of CDM and DG should be preserved and re-assessed.

In the case where CDM and DG are deemed insufficient, building Copeland Phase 2 and installing additional transformers and two new buses at Copeland MTS site is the most cost effective way to meet the required THESL needs. The site and the high voltage switching facilities required to accommodate this expansion (Copeland Phase 2) are already included as part of the Copeland MTS Phase 1 project.Copeland MTS is an underground station and is not located adjacent to residential land uses. The THESL estimated cost for Copeland MTS Phase 2 to be approximately $46 M.

[3] Further information may be found in THESL's rate application EB-2014-0116 to the Ontario Energy Board

7.4 Transmission Line Capacity – 230 kV Richview TS to Manby TS Corridor

7.4.1 Description

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto Sub-Region. It also supplies the load in the southern Mississauga and Oakville areas via Manby TS. Along this Corridor there are two double circuit 230kV lines R1K/R2K and R13K/R15K. In addition the corridor contains an idle double circuit 115kV line. Figure 7-4 shows the area supplied by Richview TS x Manby TS circuits.

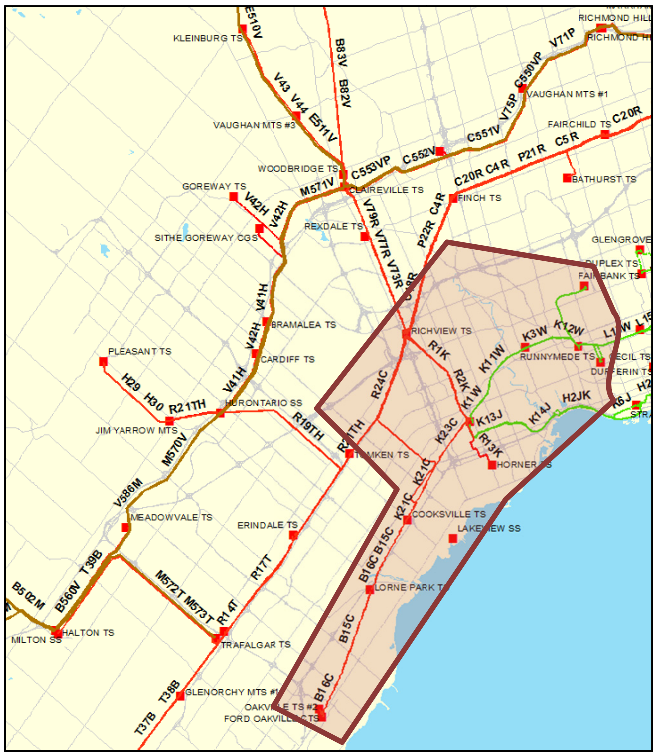

Figure 7-4 Richview x Manby Supply Area Map

The forecast loading on the Richview TS to Manby TS circuits is given in Table 7-2 below for both the high growth and low growth scenarios. The loads include the 115 kV Manby East, 115 kV Manby West, 230 kV Manby, and 230 kV Oakville-Cooksville loads. The need date for providing relief is 2020 for the high growth scenario and 2023 for the low growth scenario.

Table 7-2 also shows the effect of Metrolinx Mimico TPS on the need date for relief. In both scenarios, relief is required by 2020. The magnitude of Metrolinx load is large enough to trigger the reinforcement.

Again, due to the large incremental load from Mimico TPS, CDM will not be sufficient to help eliminate or even defer the need date for the transmission reinforcement. Transmission reinforcement is required to be implemented before the Mimico TPS can be connected.

Table 7-2 Coincident RIP MW Load Forecast for Richview TS x Manby TS Area

	Limit	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035
Base - Without Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1580**	1617	1646	1674	1698	1722	1742	1763
Low Growth	1540	1456	1481	1503	1530	**1544**	1557	1566	1572	1577	1597	1617
With Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1640**	1697	1726	1754	1778	1802	1822	1843
Low Growth	1540	1456	1481	1503	**1590**	1624	1637	1646	1652	1657	1677	1697

7.4.2 Alternatives Considered

The following alternatives are currently under consideration:

Upgrade four existing 230kV Richview TS x Manby TS circuits: Re-conductor with higher-capacity conductors on existing towers. Hydro One will check the feasibility of this option without major tower modifications and also in terms of outages arrangement. The estimated total cost of this option is about $16M, assuming that no major tower modifications and no bypass lines during re-conductoring are required.

Rebuild existing 115kV Richview TS x Manby TS line: Rebuild the existing idle 115 kV double-circuit line as a 230kV double-circuit line. The new 230 kV line is to share the existing terminations for circuits R2K and R15K at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits, effectively doubling the ampacity of R2K and R15K. This alternative requires the replacement of all the existing 115 kV towers with 230 kV towers. The estimated total cost of this option is about $19.5M.

Build two new 230 kV Richview TS x Manby TS circuits: Similar to the second alternative above, rebuild the two existing idle 115 kV double-circuit line as a 230kV double-circuit line. New terminations for these circuits are required at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits. This alternative not only provides higher transmission capacity but also increases the supply reliability to the Central Downtown and Southwest GTA area. The estimated total cost of this option is around $39.5M due to the extra station work required at the Richview TS and Manby TS.

Extend the Cooksville TS x Oakville TS line to Trafalgar TS: Extend the Cooksville TS x Oakville TS 230kV double circuit line B15C/B16C about 8km to Trafalgar TS where new 230kV switching facilties are also required. This alternative increases supply capacity and reliability to Southwest GTA area from Trafalgar TS, and thus alleviates the loading on the Richview x Manby corridor. The total estimated cost of this line and station work is around $54M.

CDM & DG: According to Central Toronto IRRP report, the potential DG development, targeted demand response and the potential incremental demand response in these areas supplied by Manby TS may defer the need for this transmission reinforcement by several years, depending on the load growth rate. However, with Mimico TPS connected near Horner TS, these targeted and potential incremental demand response will not be adequate due to the size of the extra load added by the TPS.

The Maintain Status Quo or Do Nothing alternative was not considered as it does not provide relief for the Richview x Manby transmission lines.

7.4.3 Recommended Plan and Current Status

The Metrolinx Mimico TPS information is new and was provided as part of the RIP after the IRRP was completed in April 2015. If this TPS is going to be in-service as planned in 2020, CDM initiatives will not effectively defer the need date for this transmission corridor because of the size of the additional load. Therefore, upgrading the existing Richview x Manby corridor or new supply path for the areas served by Manby TS will be required before the Metrolinx Mimico TPS can be connected.

The Trafalgar x Oakville line alternative, at $54M, is the highest cost alternative ($14.5M higher than the next most expensive alternative) and there is a risk that it may not be able to be completed in time to connect the the Metrolinx Mimico TPS in 2020. This alternative may also trigger the need for additional transformation facilities and thus would incur additional costs.

As a result, Working Group recommends that Hydro One proceed with the development and estimate work on the first three alternatives listed in Section 7.4.2 in 2016. Both EA and Section 92 approvals will be required and it is expected to take at least 3-4 years for the implementation of a wire solution. The Working Group will select the preferred alternative by December 2016. Hydro One will then plan to initiate project execution by summer 2018 in order to enable the connection of MetroLinx Mimico TPS by summer 2020.

7.5 Transmission Line Capacity – Circuit C10A (Duffin Jct. to Agincourt Jct)

C10A is a 20 km long radial circuit in Metro Toronto Northern Sub-Region from Cherrywood TS supplying Agincourt TS and Cavanagh MTS. The Metro Toronto Northern Sub-Region NA identified that the capacity of this circuit was thermally limited by a section approximately 4 km long between Duffin Jct. and Agincourt Jct. The flow on this section of the circuit might exceed its long-term emergency (LTE) rating under summer peak load conditions following certain contingencies.

A preliminary study based on the old field survey data was done in July 2015. The old record showed that the LTE rating was limited by some underbuilds along the line section. A new field survey was then carried out in October 2015. It was discovered that the aforementioned underbuilds had been previously removed, and the LTE rating of this line section should be 840A. The record is being updated. No further action is required.

7.6 Breaker Failure at Manby TS

7.6.1 Description

The failure of any of the Manby TS breakers A1H4 and H1H4 in the Manby West 230kV yard and the breaker H2H3 in the Manby east 230kV yard can cause the outage of any two of the three 230/115kV autotransformers at either the west or east yard of Manby TS. This may result in the overload of the remaining autotransformer. Based on the Coincident RIP Forecast the need date for the work is summer 2018 and summer 2021 for Manby West and Manby East respectively.

7.6.2 Recommended Plan and Current Status

The Working Group has recommended that installation of a Special Protection Scheme (SPS) is the most cost effective means to mitigate the breaker failure risk.

Hydro One is working on the development and estimate work for the SPS at Manby TS. The preliminary estimate for this work is approximately $2M and this will be updated when the development work is complete by summer 2016. The planned in-service of this work is summer 2018.

7.7 Breaker Failure at Leaside TS

The failure of breaker L14L15 at Leaside TS can cause the outage of two of the Leaside TS to Bridgman TS circuits. This may result in the loss of Transformers T11, T12, T14 and T15 at Bridgman TS. Under this scenario, two of the four LV buses will be lost by configuration. Only transformer T13 remains in service and supplies buses HLA1 and HLA7.

The 15 minute LTR for the X and Y windings of Transformer T13 is 55MVA. Therefore, as long as the loading on the HLA1 and HLA7 does not exceed the 15 minutes LTR, the operator can take action to reduce load to within transformer LTE ratings.

A new normally open switch is being installed at Bridgman TS as part of the Leaside-Bridgman Transmission Reinforcement project. This new switch can be closed remotely following the loss of the circuit L15W to resupply the two Bridgman transformers from the circuit L13W. This will alleviate the loading of the transformer T13 and the circuit L18W. and any possible voltage issue at Bridgman TS. Therefore, no investment is recommended.

7.8 Cherrywood to Leaside (CxL) Double Circuit Contingencies

Double circuit contingencies involving the lines C2L/C3L or C16L/C17L from Cherrywood TS to Leaside TS (CxL) can result in the loss of two of the three 230/115kV autotransformers on the same half of Leaside TS. The long-term emergency rating of the remaining autotransformer may be exceeded if only a single combustion unit at the Portland Energy Centre (PEC) is available, coincident with either of the abovementioned double contingencies during peak load condition.

The Working Group recommends that no further work is required in the near- and mid-term as there is already an existing operating instruction in place to cover the overload issue of the remaining Leaside autotransformer by closing the 115kV bus-tie at Leaside TS.

7.9 Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)

Bathurst TS, Fairchild TS, and Leslie TS are supplied by the 230 kV Richview x Cherrywood x Parkway system in the Metro Toronto Northern Sub-Region. Following two circuit contingencies, approximately 240-300 MW of load during summer peak time could be lost during each contingency scenario, as follows:

Table 7-3 Maximum Load Loss during Two Circuit Contingencies

Double Element Contingency	Station Connected	Non-Coincident Load Forecast (MW)	
		2015	2025
P22R + C18R	Bathurst TS	271	279
C18R + C20R	Fairchild TS	292	301
P21R + C5R	Leslie TS	239	249

There are currently no existing transmission switching facilities to allow load restoration immediately. Partial load could be restored via distribution transfer to the nearby stations.

For Bathurst and Leslie cases, the stations are supplied by circuits on separate transmission lines for all or most sections. The probability of occurrence of overlapping outages on circuits on different tower lines is extremely low. The supplied circuits for Fairchild TS are on common tower for two-third of the line (approximately 32km).

Based on the outage records in the past 25 years there has been no incidence of any double contingencies described above.

A single transformer station would require four motorized disconnect switches to be useful. Typical cost for installing these transmission switching facilities per station would be between $8-10M.

Based on the low probability of frequency of such events versus the high mitigation cost, the Working Group recommendation is that no further action is required.

7.10 Long Term Needs

Four longer term needs had been identified in the Central Toronto IRRP as follows:

- Transmission Line Capacity – 115 kV Manby West To Riverside Junction
- Transformation Capacity – 230/115 kV Manby TS
- Transformation Capacity – 230/115 kV Leaside TS
- Leaside TS x Wiltshire TS 115kV circuits

Loading on Manby TS and the Manby TS x Riverside Junction circuit are within ratings over the study period under the Coincident RIP forecast. The Working Group recommendation is that no further action is required.

The Leaside TS transformer and the Leaside TS x Wiltshire circuits will require relief in the long term. This issue will be considered in the next planning cycle. The Working Group recommendation is that no further action is required. However, Hydro One and IESO will continue to monitor loads and initiate necessary relief measures, if required.

8. CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE METRO TORONTO REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Supply Security – Breaker Failure at Manby West & East TS
II	West Toronto Area - Station Capacity and Line Capacity
III	Southwest Toronto - Station Capacity
IV	Downtown District - Station Capacity
V	230 kV Richview x Manby Corridor– Line Capacity
VI	Leaside Autotransformers
VII	Line Capacity – 115 kV Leaside x Wiltshire Corridor

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near-term and mid-term needs are summarized in the Table 8-2 below. Investments to address the long-term needs where there is time to make a decision (Need No. VI & VII), will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Est. Cost	Needs Mitigated
1	Manby SPS	Transmitter to carry out the work	Hydro One	2018	$2M	I
2	Runnymede Expansion & 115 kV Manby x Wiltshire Corridor Upgrade	Transmitter to carry out the work	Hydro One	2019	$90M	II
3	Horner Expansion	Transmitter to carry out the work	Hydro One	2020	$53M	III
4	230 kV Richview x Manby Corridor Upgrade	Transmitter to carry out the work	Hydro One	2020	$20-40M	V
5	Copeland Phase 2	LDC to carry out work & monitor growth	THESL	2020+	$46M	IV

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered every five years. The next planning cycle for the Metro Toronto Region is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1]. Independent Electricity System Operator, "Central Toronto Integrated Regional Resource Plan", 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/2015-Central-Toronto-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, Metro Toronto Region – Northern Sub-Region", 11 June 2014.
http://www.hydroone.com/RegionalPlanning/Toronto/Documents/Needs%20Assessment%20Report%20-%20Metro%20Toronto%20-%20Northern%20Subregion.pdf

Appendix A. Stations in the Metro Toronto Region

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L13W/L15W/L14W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Dufferin TS T1/T3	115/13.8	L13W/L15W
Dufferin TS T2/T4	115/13.8	L13W/L15W
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10EJ(C5E)/H9EJ(C7E)
Fairbank TS T1/T3	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W
Fairchild TS T1/T2	230/27.6	C18R/C20R

Station (DESN)	Voltage (kV)	Supply Circuits
Fairchild TS T3/T4	230/27.6	C18R/C20R
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T3/T4	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	C2L/C3L/C16L
Leaside TS T19/T20/T21 27.6	230/27.6	C2L/C3L/C16L
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T3/T4	115/27.6	K12W/K11W

Station (DESN)	Voltage (kV)	Supply Circuits
Scarboro TS T21/T22	230/27.6	C14L/C2L
Scarboro TS T23/T24	230/27.6	C15L/C3L
Sheppard TS T1/T2	230/27.6	C16L/C15L
Sheppard TS T3/T4	230/27.6	C15L/C16L
Strachan TS T12/T14	115/13.8	H2JK/K6J
Strachan TS T13/T15	115/13.8	K6J/H2JK
Terauley TS T1/T4	115/13.8	C7E/C5E
Terauley TS T2/T3	115/13.8	C7E/C5E
Warden TS T3/T4	230/27.6	C14L/C17L
Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T2/T5	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T3/T4	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
IBM Markham CTS T1/T2	230/13.8	P21R/P22R
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Copeland MTS T1/T3 (Future)	115/13.8	D11J/D12J

Appendix B. Transmission Lines in the Metro Toronto Region

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	H9EJ, H10EJ	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

Appendix C. Distributors in the Metro Toronto Region

Distributor Name	Station Name	Connection Type
Toronto Hydro-Electric System Limited	Agincourt TS	Tx
	Basin TS	Tx
	Bathurst TS	Tx
	Bermondsey TS	Tx
	Bridgman TS	Tx
	Carlaw TS	Tx
	Cecil TS	Tx
	Charles TS	Tx
	Dufferin TS	Tx
	Duplex TS	Tx
	Ellesmere TS	Tx
	Esplanade TS	Tx
	Fairbank TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Gerrard TS	Tx
	Glengrove TS	Tx
	Horner TS	Tx
	John TS	Tx
	Leaside TS	Tx
	Leslie TS	Tx
	Main TS	Tx
	Malvern TS	Tx
	Manby TS	Tx
	Rexdale TS	Tx
	Richview TS	Tx
	Runnymede TS	Tx
	Scarboro TS	Tx
	Sheppard TS	Tx
	Strachan TS	Tx
	Terauley TS	Tx
	Warden TS	Tx
	Wiltshire TS	Tx
	Cavanagh MTS	Tx
	Copeland MTS (Future)	Tx

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc. (Dx)	Agincourt TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Leslie TS	Tx
	Malvern TS	Tx
	Richview TS	Tx
	Sheppard TS	Tx
	Warden TS	Tx
PowerStream Inc.	Agincourt TS	Dx
	Fairchild TS	Dx
	Finch TS	Dx
	Leslie TS	Dx
Veridian Connections Inc.	Malvern TS	Dx
	Sheppard TS	Dx
Enersource Hydro Mississauga Inc.	Richview TS	Dx

Appendix D. Metro Toronto Regional Load Forecast (2015-2035)

Table D-1 Non-Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	Lea115	Basin	84	57	60	64	67	68	69	70	71	73	75	77	79	81	83
		Bridgman	179	174	177	179	181	182	183	184	185	187	189	191	193	195	198
		Carlaw	131	65	66	68	70	71	73	74	72	71	72	75	78	80	82
		Cecil	204	168	169	171	173	175	177	178	181	183	186	190	193	196	199
		Charles	200	151	153	156	158	159	161	162	165	167	170	172	173	177	181
		Dufferin	161	141	144	147	149	150	150	150	152	154	156	158	159	161	163
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	196	201	206	210	215
		Gerrard	62	44	45	46	48	49	50	51	63	78	88	90	92	93	94
		Glengrove	84	55	57	58	59	60	60	61	62	63	64	66	67	68	69
		Main	72	65	64	63	62	63	64	66	65	65	66	69	72	75	77
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	Wiltshire	113	67	68	69	70	70	71	72	72	72	72	73	74	75	76
	ManbyE115-27.6	Runnymede	109	116	118	120	122	122	123	123	125	126	128	129	131	132	133
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	175	178	181	184	186	187	188	190	193	195	197	199	201	203
	ManbyW115	Copeland	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	276	276	189	189	192	195	198	202	206	209	213	218	221	225
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2143	2175	2206	2255	2279	2303	2341	2390	2444	2495	2540	2587	2626	2666
Eastern 230kV	CxL230	Bermondsey	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	169	171	173	175	175	175	175	176	177	178	180	181	182	183
		Leaside	210	156	158	159	161	161	161	161	163	165	166	168	170	172	174
		Scarboro	340	222	225	227	230	230	230	230	231	233	234	236	238	239	241
		Sheppard	204	170	170	171	171	171	171	171	173	174	175	176	178	179	180
		Warden	183	126	128	129	130	130	130	130	131	132	133	134	135	136	137
	Metrolinx	Metrolinx - Warden	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1037	1047	1057	1067	1067	1107	1127	1155	1164	1172	1180	1189	1197	1206
Northern 230kV	CxR	Agincourt	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	271	272	274	275	275	275	275	277	279	281	283	285	287	289
		Cavanagh	157	141	141	141	142	142	142	142	143	144	145	146	147	148	149
		Fairchild	357	292	293	295	297	297	297	297	299	301	303	306	308	310	312
		Finch	363	289	292	295	298	298	298	298	300	302	304	306	309	311	313
		Leslie	325	239	241	244	246	246	246	246	248	249	251	253	255	256	258
		Malvern	176	106	106	107	107	107	107	107	108	109	109	110	111	112	113
Northern 230kV Total			1885	1433	1444	1455	1466	1467	1468	1469	1479	1490	1500	1511	1521	1532	1543
Western 230kV	Manby230	Horner	179	144	146	148	150	151	152	153	155	157	157	156	155	157	159
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	Metrolinx - Cityview	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	Rexdale	187	135	135	135	135	134	133	132	133	134	135	136	137	138	139
		Richview T1T2EZ	154	130	131	131	131	130	129	128	129	130	131	132	133	134	135
		Richview T5T6JQ	188	109	110	110	110	109	108	108	108	109	110	111	111	112	113
		Richview T7T8BY	113	54	54	54	54	54	54	53	54	54	54	55	55	56	56
Western 230kV Total			1042	805	811	818	825	825	905	945	994	1003	1013	1023	1034	1043	1052
Grand Total			6995	5419	5477	5537	5613	5638	5783	5883	6019	6100	6180	6254	6331	6398	6466

Table D-2 Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	**Lea115**	**Basin**	84	52	55	58	61	62	63	63	65	66	68	70	72	73	75
		Bridgman	179	171	173	175	177	179	180	181	182	183	185	187	189	192	194
		Carlaw	131	61	63	65	67	68	69	70	69	68	68	71	74	76	78
		Cecil	204	152	154	156	158	159	161	162	165	167	170	173	176	178	181
		Charles	200	150	152	155	157	159	160	161	164	166	169	171	172	176	180
		Dufferin	161	139	142	144	147	147	148	148	150	152	153	155	157	159	160
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	195	200	206	210	215
		Gerrard	62	44	45	46	47	48	49	50	62	77	87	89	91	92	93
		Glengrove	84	52	53	55	56	57	57	58	59	60	61	62	64	64	65
		Main	72	59	59	58	57	58	59	60	60	60	61	64	67	69	71
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	**Wiltshire**	113	61	61	62	63	64	64	65	65	65	65	66	67	68	69
	ManbyE115-27.6	**Runnymede**	109	96	98	99	101	101	102	102	103	105	106	107	109	110	110
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	174	177	179	183	184	185	186	188	191	193	195	197	199	201
	ManbyW115	**Copeland**	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	267	266	179	179	182	185	188	191	195	199	202	206	210	213
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2067	2097	2128	2176	2198	2222	2259	2307	2359	2409	2453	2498	2536	2575
Eastern 230kV	**CxL230**	**Bermondsey**	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	154	155	157	159	159	159	159	160	161	162	163	164	166	167
		Leaside	210	154	156	158	159	159	159	159	161	163	165	167	168	170	172
		Scarboro	340	220	222	225	227	227	227	227	229	230	232	234	235	237	239
		Sheppard	204	164	164	165	165	165	165	165	166	168	169	170	171	172	174
		Warden	183	125	126	127	129	129	129	129	130	130	131	132	133	134	135
	Metrolinx	**Metrolinx - Warden**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1010	1020	1030	1040	1040	1080	1100	1128	1136	1144	1152	1160	1168	1176
Northern 230kV	**CxR**	**Agincourt**	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	245	247	248	249	249	249	249	251	253	255	257	258	260	262
		Cavanagh	157	119	119	119	120	120	120	120	120	121	122	123	124	125	126
		Fairchild	357	256	257	259	260	260	260	260	262	264	266	268	270	272	273
		Finch	363	273	276	278	281	281	281	281	283	285	287	289	291	293	295
		Leslie	325	223	225	227	229	229	229	229	231	233	234	236	238	239	241
		Malvern	176	106	106	106	107	107	107	107	108	108	109	110	111	111	112
Northern 230kV Total			1885	1317	1327	1337	1347	1348	1349	1351	1360	1370	1379	1389	1399	1408	1418
Western 230kV	**Manby230**	**Horner**	179	129	131	133	135	136	137	138	140	141	142	141	139	141	143
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	**Metrolinx - Cityview**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	**Rexdale**	187	133	133	133	133	132	131	130	131	132	133	134	135	136	137
		Richview T1T2EZ	154	128	128	129	129	128	127	126	127	128	129	130	131	131	132
		Richview T5T6JQ	188	107	107	108	108	107	106	106	106	107	108	109	109	110	111
		Richview T7T8BY	113	52	52	52	52	52	51	51	51	52	52	53	53	53	54
Western 230kV Total			1042	782	788	794	801	801	881	921	970	979	988	998	1009	1018	1027
Grand Total			6995	5176	5232	5289	5363	5388	5532	5631	5765	5843	5920	5992	6066	6131	6196

Appendix E. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Northwest Ontario

REGIONAL INFRASTRUCTURE PLAN

June 9, 2017

hydro one

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Atikokan Hydro Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Kenora Hydro Electric Corporation Ltd.
Thunder Bay Hydro Electricity Distribution Inc.
Sioux Lookout Hydro Inc.
Fort Frances Power Corporation

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH INPUT AND SUPPORT FROM THE WORKING GROUP IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE NORTHWEST ONTARIO REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Atikokan Hydro Inc.
- Kenora Hydro Electric Corporation Ltd.
- Thunder Bay Hydro Electricity Distribution Inc.
- Sioux Lookout Hydro Inc.
- Fort Frances Power Corporation

This RIP is the final phase of the regional planning process and it follows the completion of Integrated Regional Resource Plan ("IRRP") by the IESO for the North of Dryden Sub-Region in January 2015, Greenstone-Marathon Sub-Region in June 2016, and West of Thunder Bay in July 2016 and for Thunder Bay Sub-Region in December 2016 [2-5]. This report also references the IESO Draft Remote Community Connection Plan report [6].

This RIP provides a consolidated summary of needs and recommended plans for North of Dryden, Greenstone-Marathon, West of Thunder Bay, and Thunder Bay Sub -Regions that make up the Northwest Ontario Region. The potential needs of the bulk system is not within the scope of the Regional Planning, however, some aspects of the bulk system needs and plans are discussed in this report in the context of regional plans.

The Working Group has reassessed and updated the LDC load forecasts, which have remained consistent with the forecasts used in the IRRPs. Accordingly, this RIP has confirmed the needs and the proposed or recommended infrastructure (wires) plans for the sub-regions as indicated in the IRRP reports.

The needs in the region are largely driven by the industrial load growth, particularly the mining sector. Considering the uncertainties in the forecast of the industrial loads, this RIP uses the forecast scenarios and assumptions developed for the Northwest IRRPs. The connection of remote communities to the electricity grid, as well as the load growth as a result of economic developments, are also contributing factors. Since the development timelines and plans for connection of the mining and other industrial loads are uncertain and frequently depend on the customer decision, the IRRP and RIP have both considered low, medium (or reference) and high load growth scenarios and identified alternatives and recommended plans to address the needs under each scenario in near-term (present-5 years), mid-term (5-10 years) and long term (10-20 years).

The following is the summary of the currently recommended or proposed near/mid/long-term wires plans for the sub-regions under low, medium and high load growth scenarios. The current status of these plans is also indicated in the following.

North of Dryden Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
1	Circuits E1C and E4D Capacity	A 230 kV transmission line from Dryden/Ignace area to Pickle Lake	Medium[1]	Near-term	Recommended in IRRP. Development has started.
2	Circuits E4D and E2R Capacity	Upgrade of transmission lines E2R and E4D, and additional voltage support	All Scenarios	Near-term	Recommended in IRRP. The need has not materialized.
3		A 115 kV or 230 kV transmission line from Dryden to Ear Falls	High	Long-term	Proposed in IRRP. Not needed in the planning horizon, assuming Projects 1 and 2 proceed.

Greenstone-Marathon Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
4	Circuit A4L Capacity	Upgrade of sections of transmission line A4L, and dynamic voltage support devices at Geraldton	Medium[2]	Near-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Geraldton mine.
5		Upgrade of other sections of transmission line A4L	Medium[2]	Mid-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Beardmore mine.
6	Capacity for Pipeline Project and Ring of Fire	A 230 kV transmission line from Nipigon or Terrace Bay to Geraldton, and voltage support devices	High[2]	Mid/Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of pipeline loads and mines.
7		A 115 kV transmission line from Manitouwadge to Geraldton, and voltage support devices	High[2]	Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of additional pipeline loads.

[1] The Medium growth scenario for North-of-Dryden sub-region corresponds to the "Reference Scenario" in the IRRP

[2] The Low growth scenario for Greenstone-Marathon sub-region corresponds to scenario "A" of the three sub-systems in the IRRP, the Medium growth scenario corresponds to scenario "B" of Greenstone and Marathon and scenario A of Northshore sub-systems in the IRRP, and the High growth scenario corresponds to scenario "D" of Greenstone, scenario "C" of Marathon and scenario "A" of Northshore sub-systems in the IRRP (see section 5 for details of Load Forecast Scenarios).

West of Thunder Bay Sub-Region Wires Plans					
No.	Need	Wires Options	Load Growth	Term	Status
8	Dryden 115 kV System Capacity	A 230/115 kV auto-transformer in Dryden area	High	Mid-term	Proposed in IRRP. Next planning cycle will reassess the need.

Thunder Bay Sub-Region Wires Plans					
No.	Need	Wires Options	Load Growth	Term	Status
9	Thunder Bay 115 kV System Capacity	A 230/115 kV auto-transformer in Thunder Bay area	High	Long-term	Proposed in IRRP. Next planning cycle will reassess the need.
10	Port Arthur TS Transformation Capacity	Upgrade of Low-Voltage equipment at Port Arthur TS	All Scenarios	Long-term	Proposed in IRRP. LV equipment are planned for End-of-Life replacement in mid-term. Next planning cycle will reassess the need.

The IRRP for Thunder Bay sub-region identified a near-term need for upgrading the thermal rating of circuit R2LB between Lakehead TS and Birch TS to that of the companion circuit R1LB. This upgrade has been completed in Q4 2016.

Most of the above plans are highly dependent on the needs of industrial customers in the region. Proceeding to the Development phase for the customer-driven projects requires request by, and agreement with, the customer(s). Currently, only Project No. 1 has proceeded to the Development phase. The only supply point in the region which is presently at its load-meeting capability limit is Pickle Lake and Project No. 1 will address the need at this location.

Additionally, the IESO Draft Remote Community Connection Plan report [6] has recommended the connection of 21 First Nations communities in the northern part of the region to the electricity grid. An Order in Council from the government, dated July 20, 2016, has directed the OEB to amend Wataynikaneyap Power LP's transmitter licence to develop and seek approvals for the connection of sixteen remote communities and the Dryden-Pickle Lake transmission line, i.e. Project No. 1 identified above.

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. There is adequate time to review the proposed or recommended plans to meet the long-term needs and develop preferred alternatives in the next planning cycle. Should there be a need that emerges prior to the next planning cycle such as but not limited to change in load forecast, the regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE NORTHWEST ONTARIO REGION.

The report was prepared by Hydro One Networks Inc. - Transmission ("Hydro One") with input and on behalf of the Working Group that consists of Hydro One, Hydro One Networks Inc. - Distribution, the Independent Electricity System Operator ("IESO"), Atikokan Hydro Inc., Kenora Hydro Electric Corporation Ltd., Thunder Bay Hydro Electricity Distribution Inc., Sioux Lookout Hydro Inc. and Fort Frances Power Corporation in accordance with the Regional Planning process established by the Ontario Energy Board in 2013.

Northwest Ontario region is divided into 4 sub-regions: City of Thunder Bay, West of Thunder Bay, North of Dryden, and Greenstone-Marathon. The IESO has also assessed the economic case for connecting the Remote Communities north of Red Lake and Pickle Lake to the provincial grid. Electrical supply to the Region is provided by fifty two 230kV and 115kV transmission and distribution stations. Some of the stations are shown in Figure 1-1.

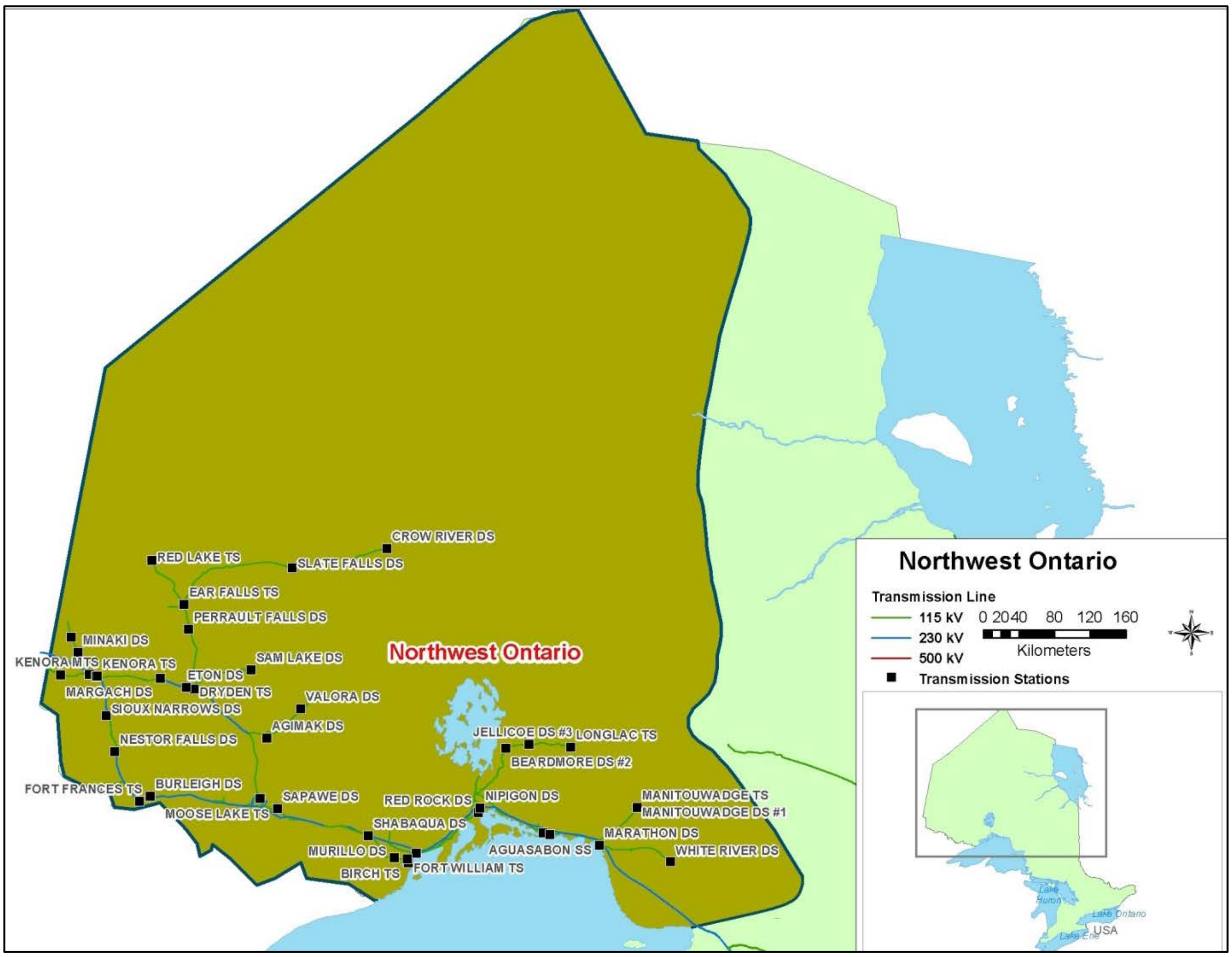

Figure 1-1 Map of Northwest Ontario Region

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1.1 Scope and Objectives

This RIP report examines the needs in the Northwest Ontario Region. Its objectives are to:

- Review of needs (near and medium-term) identified through the IRRP process.
- Develop a wires plan to address all needs where wires solution is the most appropriate.
- Discuss long-term needs identified during the planning process

The RIP reviews factors such as the LDC load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period;
- Develop an approach to address any longer term needs identified by the Working Group.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process;
- Section 3 describes the region;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast used in this assessment;
- Section 6 discusses the needs and provides the alternatives and preferred solutions;
- Section 7 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [3] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address one or more of the needs. If no further regional coordination is required and localized needs cannot be met by non-wires solutions, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and a Local Plan ("LP") is developed to address localized needs. Ultimately, local plans are also incorporated into the RIP report.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions and/or different needs.

The IRRP phase will generally assess integrated alternatives consisting of infrastructure (wires) and/or resource (CDM and Distributed Generation). Detailed information regarding wires options may not be available or necessary within the scope of the IRRP. The level of detail for wires options as part of the IRRP will be to a level which is sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and refine the assessment of specific wires alternatives, and recommend a preferred

[3] Also referred to as Needs Screening.

wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and may establish Local Advisory Committees (LAC) in the region or sub-region. For the Northwest Ontario Region, community engagement through a number of LACs is on-going.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

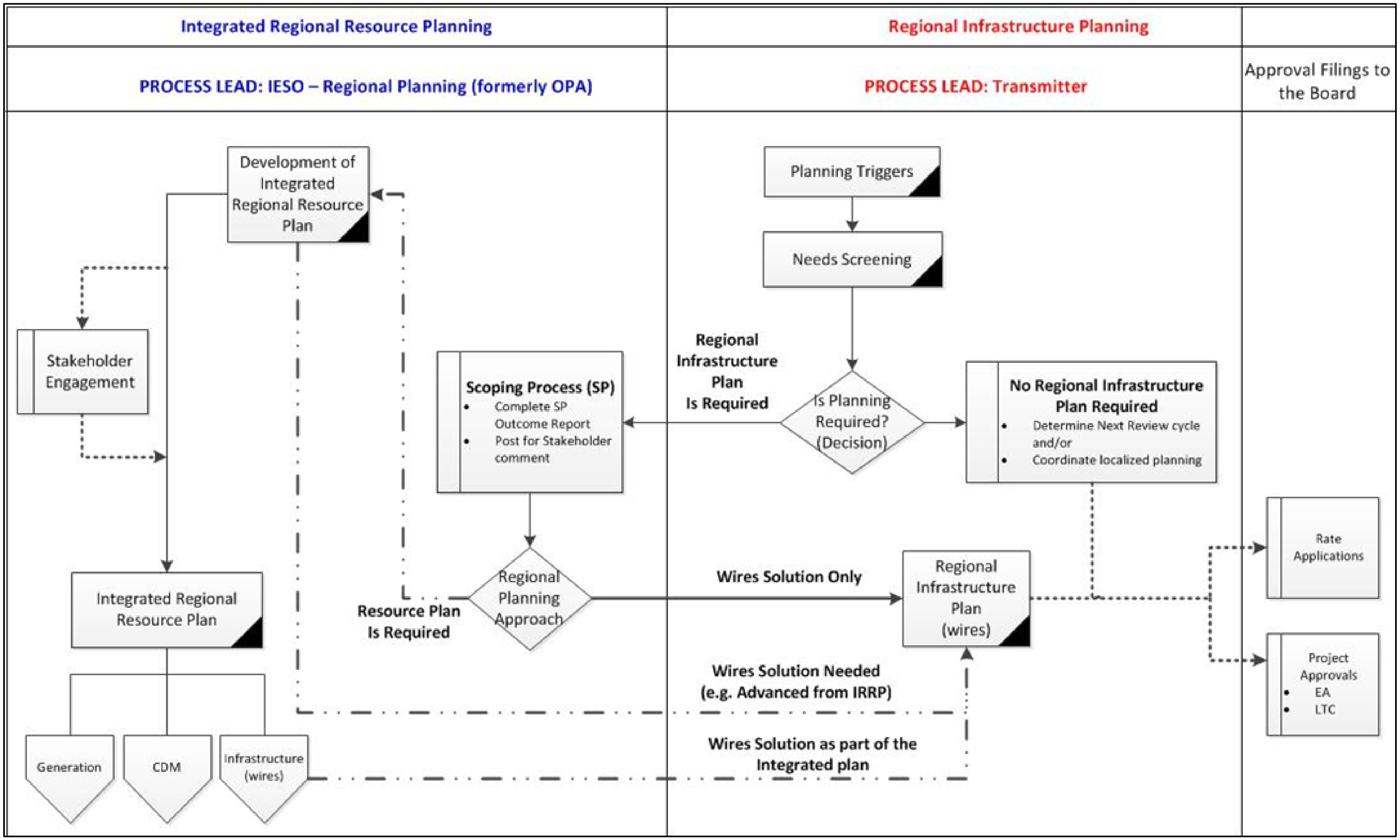


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1) Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

The extent and scope of each step naturally depends on the outcome of the previous step. The outcome of the previous stage of the regional planning process, i.e., IRRP, also influences the scope of Step 2 to a large extent.

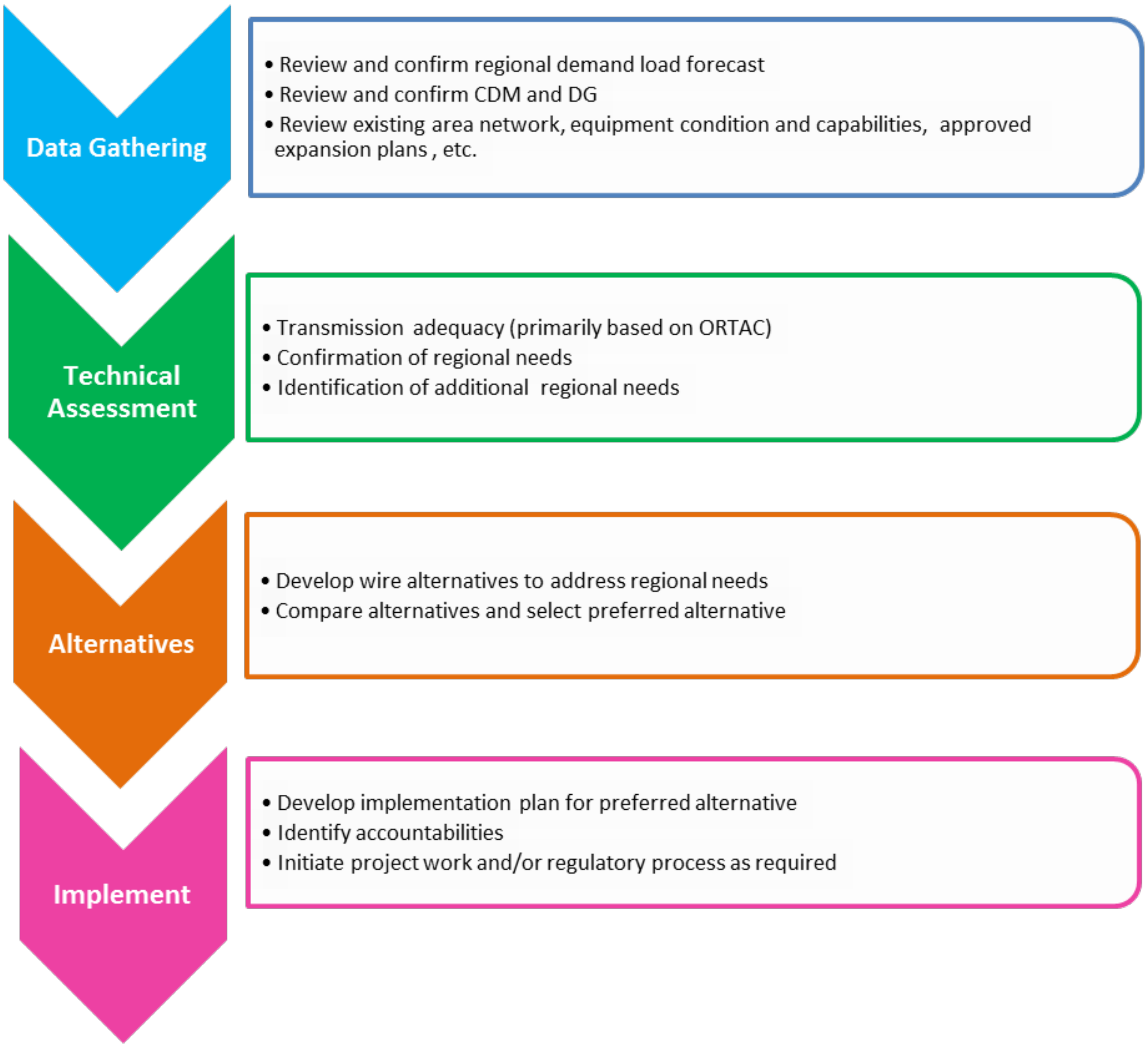


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

NORTHWEST ONTARIO REGION IS ROUGHLY BORDERED BY WEST OF HUDSON BAY AND JAMES BAY, NORTH AND WEST OF THE LAKE SUPERIOR, AND EAST OF THE CANADIAN PROVINCE OF MANITOBA. THE REGION CONSISTS OF THE DISTRICTS OF THUNDER BAY, KENORA AND RAINY RIVER. ALMOST 54 PERCENT OF REGION'S ENTIRE POPULATION LIVES IN THUNDER BAY. THE REGION ACCOUNTS FOR APPROXIMATELY 60 PERCENT OF LAND AREA OF THE PROVINCE AND ABOUT TWO PERCENT OF ONTARIO'S TOTAL POPULATION.

Bulk electrical supply to the Northwest Ontario Region is provided through a combination of local generation stations connected to the 230 kV and 115 kV network, and the East-West Tie transmission corridor.

The Local Distribution Companies ("LDCs") that serve the electricity demands for the Northwest Ontario are Hydro One Networks Inc. (Distribution), Atikokan Hydro Inc., Kenora Hydro Electric Corporation Ltd., Sioux Lookout Hydro Inc., Thunder Bay Hydro Electricity Distribution Inc., and Fort Frances Power Corporation. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The January 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report for North of Dryden Sub-Region, the June 2016 IRRP report for Greenstone-Marathon Sub-Region, the July 2016 IRRP report for West of Thunder Bay Sub-Region, and the December 2016 IRRP report for Thunder Bay Sub-Region focused on northern, eastern, western, and central parts, respectively, of the Region. All IRRP reports were prepared by the IESO in conjunction with Hydro One and the LDC. A map and a single line diagram showing the electrical facilities of the Northwest Ontario Region, consisting of the sub-regions, is shown in Figure 3-1 and Figure 3-2, respectively.

3.1 North of Dryden Sub-Region

A radial single-circuit 115 kV transmission line ("E4D") supplies electricity to the customers in the North of Dryden sub-region from Dryden TS. The major supplying station for this sub-region is Dryden TS, where the voltage is stepped down from the 230 kV to 115 kV, to serve local and industrial customers. Electricity demand in the North of Dryden sub-region is also supplied by local hydroelectric generation.

3.2 Greenstone-Marathon Sub-Region

Electrical supply to the customers in the Greenstone-Marathon Sub-Region comprises of Marathon TS and Alexander Switching Station ("SS"). Located in the town of Marathon, Marathon TS connects the Northwest electrical system to the East Lake Superior electrical system at Wawa TS, with two 230 kV lines - W21M and W22M. Marathon TS steps down 230 kV to 115 kV and supplies customers in the

Town of Marathon, White River and Manitouwadge through a 115 kV single circuit - M2W. Three circuits A5A, A1B, and T1M - in series connect Marathon TS to Alexander SS.

Alexander SS connects Alexander Generating Station ("GS"), Cameron Falls GS, and Pine Portage GS - to the system. A 115 kV single-circuit A4L, connected to the Alexander SS, supplies electricity to the Municipality of Greenstone and its surrounding areas. Nipigon GS is also connected to the circuit A4L.

3.3 West of Thunder Bay Sub-Region

Supply to this Sub-Region is provided from a 230 kV transmission system consisting of the Kenora TS, Fort Frances TS, Dryden TS, and Mackenzie TS. Kenora TS steps down 230 kV to 115 kV and supplies customers in the City of Kenora and surrounding areas. In addition, it also connects Ontario to Manitoba's electrical system through two 230 kV transmission lines – K21W and K22W. Fort Frances TS steps down 230 kV to 115 kV and supplies customers in the City of Fort Frances and surrounding areas. It also connects Ontario to Minnesota's electrical system through a 115 kV transmission line – F3M. Dryden TS steps down 230 kV to 115 kV and supplies customers in the City of Dryden and surrounding areas. It also connects West of Thunder Bay to North of Dryden Sub-Region. Mackenzie TS steps down 230 kV to 115 kV and supplies customers in Atikokan and surrounding areas. It also connects West of Thunder Bay to the Thunder Bay Sub-Region. The West of Thunder Bay Sub-Region is also supplied by many local hydroelectric generation facilities

3.4 Thunder Bay Sub-Region

Thunder Bay Sub-Region consists of the Lakehead TS as the 230 kV step-down transformation facility which steps down 230 kV to 115 kV and supplies customers in the City of Thunder Bay and surrounding areas. The area is served primarily at 115 kV by three step-down transformer stations - Birch TS, Fort William TS, and Port Arthur TS #1.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

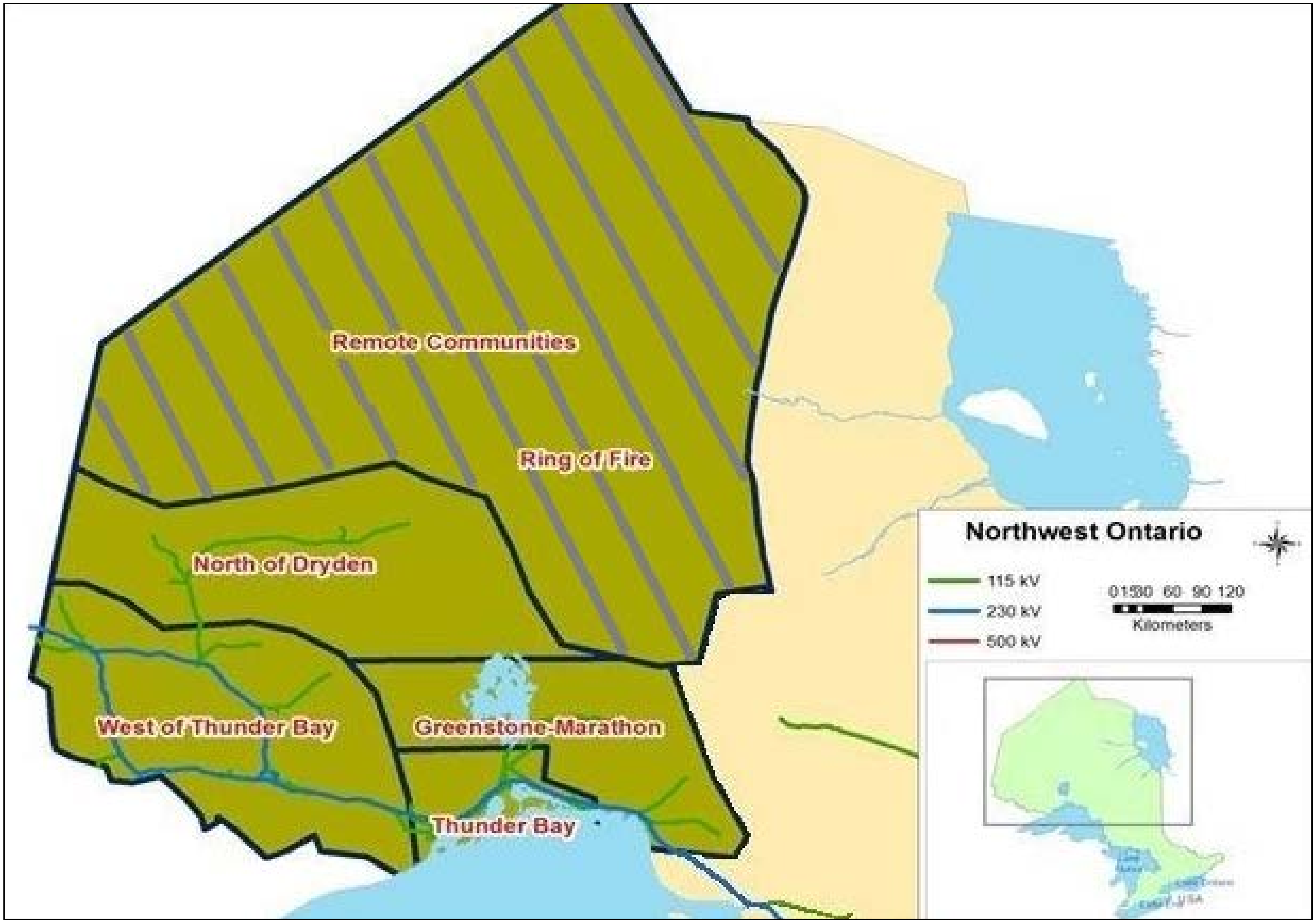


Figure 3-1 Northwest Ontario Region – Supply Areas

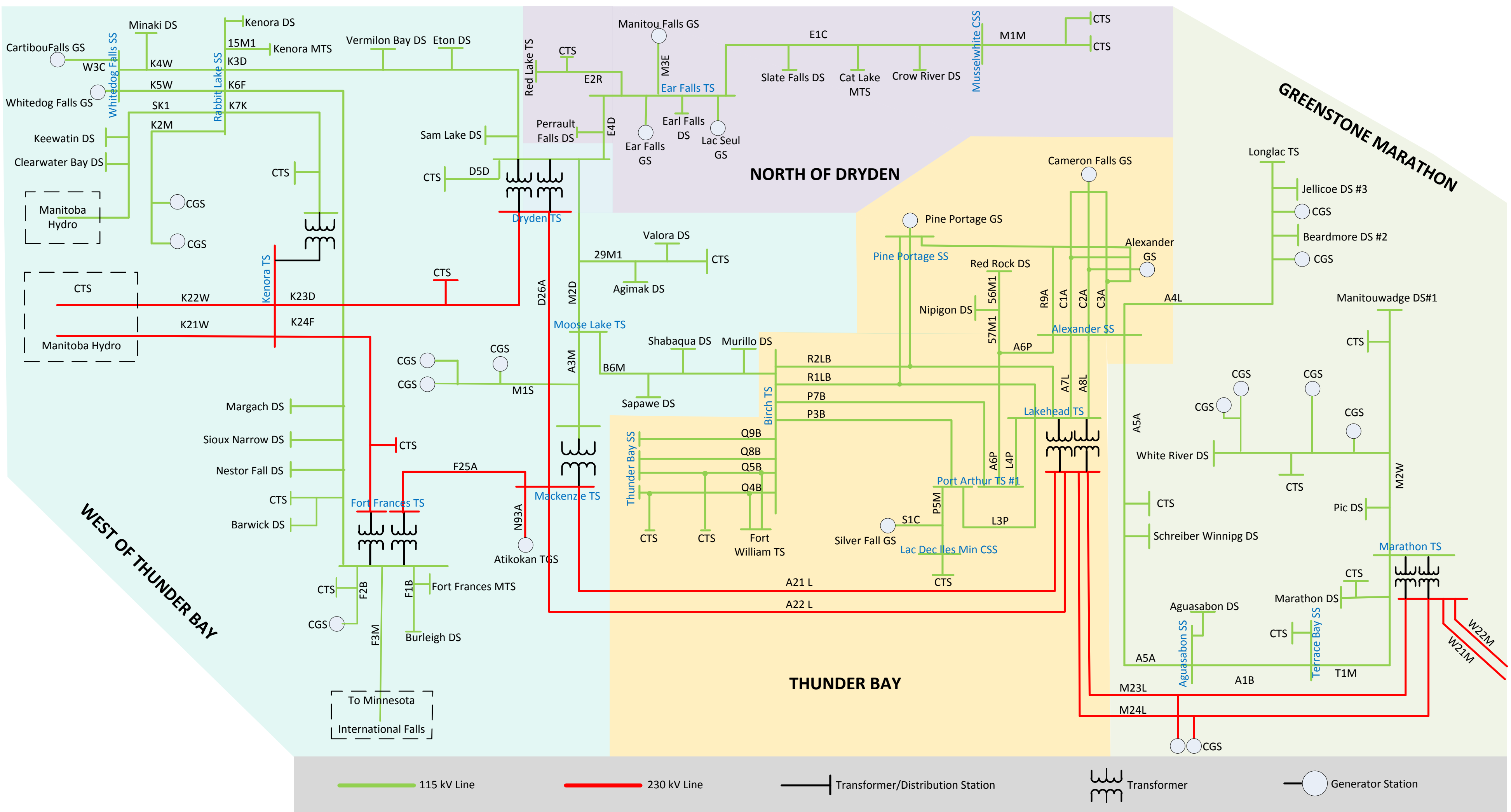


Figure 3-2 Northwest Ontario Region – Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS AND PLANNED FOR NEAR FUTURE

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, ARE UNDERWAY, OR ARE PLANNED FOR THE COMING YEARS, AIMED AT IMPROVING THE SUPPLY TO THE NORTHWEST ONTARIO REGION IN GENERAL.

This section describes the completed development and sustainment projects in the region, as well as the sustainment projects that are in the execution stage or planned for the coming years.

4.1 Past Major Projects

In the past 10 years, the following are some of the major projects completed in the Northwest Ontario Region.

1. **Barwick TS** –Barwick TS was built in the second and third quarter of 2013 to replace load-serving facilities at Fort Frances TS as majority of these assets were reaching the end of their useful life. The new facilities include: two 42 MVA 115/44 kV transformers and the associated breakers, switches, surge arresters, etc. and two cap banks, each rated 4.9 MVAR at 44 kV, and the associated breakers and switches.

2. **Birch TS –** One of three 42 MVA step down transformers (115/25 kV) at Birch TS was replaced in December 2015.

3. **Dryden TS** – In addition to replacing 5 HV breakers, 2 LV breakers and 12 switches between 2014-2016, 2x40 MVAR Shunt reactors at Dryden TS were installed in Q3 2014.

4. **Fort Frances** – In addition to replacing 2 LV breakers and 8 switches (2010-2016), 21.6 MVAR/13.8 kV capacitor bank was installed at Fort Frances in November 2010.

5. **Kenora TS** – 1 LV breaker and 4 switches were replaced between 2009 and 2015.

6. **Lakehead TS** – 3 HV breakers, 1 LV breaker, 5 switches, and 1 autotransformer (230/13.9 kV) were replaced between 2009 and 2016 as part of the sustainment work. In addition, one synchronous condenser at Lakehead TS was replaced by a +60/-40 MVAR SVC in December 2009.

7. **Longlac TS** –Transformers T2 and T3 were replaced with two 42 MVA 115/44 kV transformers and associated equipment protections i.e. breakers, switches, surge arresters, etc. In addition, four capacitor banks; each rated at 4.9 MVAR at 44 kV with associated breaker and switches were installed. This work was completed mid-2011.

8. **Manitouwadge TS** – 1 LV breaker, 1 switch, and 1 step down transformer (115/44 kV) were replaced in July 2016.

9. **Marathon TS** – In addition to replacing 1 HV breaker, 2 LV breakers, and 4 switches between 2009 and 2016, 2x40 MVAR shunt reactors were installed in December 2013 and March 2014.

10. **Moose Lake TS** – 5 HV breakers were replaced in 2014.

11. **Port Arthur TS #1** – 10 switches were replaced between 2009 and 2015. In addition, 2x0.5 ohms LV current limiting reactors were replaced with 2x1 ohm reactor. Work was completed in December 2014.

12. **Rabbit Lake SS** – 2 HV breakers and 4 switches were replaced between 2011 and 2016.

13. **Red Lake TS** –Five capacitor banks were upgraded by 2.5 MVAR each to 7.4 MVAR (at 44 kV). This work also included upgrading associated breakers and switches and was completed between December 2015 and July 2016.

4.2 Current or Planned Major Sustainment Projects

The following major sustainment projects are currently under execution or planned for the coming years. These projects are based on the assessment of end of life issues of the aging station's equipment and replacing those that represent risk to the security of the bulk transmission system and reliability for connected customers.

1. **Dryden TS**– is located in the city of Dryden and supplies majority of the customers in the area. It consists of three 115/44 kV power transformers rated at 15MVA each, which are non-standard units and are about 69 years old.

   Hydro One has planned to replace the three EOL transformers with two new standard-size transformers, rated at 42MVA each. The scope of work also includes the replacement of other deteriorating infrastructure, such as LV switchyard (which will be built to current standard), 115 kV OCBs, and select switches.

   This project is currently planned to be completed in 2018.

2. **Ear Falls TS** – supplies customers in the city of Ear Falls in the North of Dryden Sub-Region, through a single transformer T5 (115/44 kV, 19 MVA), backed-up by a spare transformer T5SP (115/44 kV, 8 MVA). The 44 kV LV voltage is further stepped-down to 12.5 kV through Ear Falls DS transformer T1 (44/12.5 kV). Ear Falls TS transformers T5 and T5SP are approximately 47 and 69 years old, respectively, while Ear Falls DS T1 is currently 49 years old.

   Hydro One has planned to eliminate the need for 44 kV to 12.5 kV conversion at Ear Falls DS by replacing T5 and T5SP transformers with 115/13.2 kV transformer units (rated at 12.5 MVA each). The scope of work also involves replacing 44kV equipment with 13.2 kV, replacing 115 kV circuit breakers, and replacing EOL protections, controls, and telecom in new relay building to ensure the integrity of power system protection is maintained.

   This project is currently planned to be completed in 2018.

3. **Alexander SS** – is a 115 kV switching station located in the Thunder Bay Sub-Region and was originally built in 1955. The station terminates five 115 kV circuits for the supply of customers in the area and connects 161 MW of generation from the Nipigon River and Cameron Falls. It consists of ten 115 kV breakers, nine of which are non-standard.

Hydro One has planned to replace all non-standard and EOL equipment at the station. The scope of work involves replacing 115 kV oil circuit breakers with new SF6 breakers, replacing select switches, upgrade of all protection & control facilities and AC station service system.

This project is currently planned to be completed in 2019.

4. **Birch TS** – is a 115 kV transmission station located in City of Thunder Bay in the Thunder Bay Sub-Region and was put in-service in 1955. Birch TS is comprised of a DESN station which supplies local load in the port area of Thunder Bay, as well as being a 115 kV bulk station with 9 lines and the three DESN transformers connected to it.

   Due to the criticality of the station to both transmission and distribution systems, protection and control equipment that is presently located in the basement will be relocated to a new relay building. The scope of work involves replacing 115 kV circuit breakers and 25 kV capacitor banks, and replacing/relocating end of life protections in the new relay building.

   This project is currently planned to be completed in 2019.

5. **Pine Portage SS** – is a 115 kV switching station located in the Greenstone-Marathon Sub-Region and was put in-service in 1954. The switching station has three outgoing 115 kV transmission lines connecting to Lakehead TS, Birch TS and Alexander SS. Pine Portage GS is also connected to this switching station.

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing five 115 kV oil circuit breakers with new 2000A SF6 breakers, associated disconnect switches, protection, control and teleprotection facilities.

   This project is currently planned to be completed in 2020-2023.

6. **Aguasabon SS** – is a 115 kV switching station in Greenstone-Marathon Sub-Region and was put in-service in 1948. The station has two transmission lines connecting to Alexander SS and Terrace Bay SS. The station is also critical to the connection of Aguasabon DS.

   Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing/upgrading AC/DC station service, and replacing equipment protections.

   This project is currently planned to be completed in 2021-2024.

7. **Port Arthur TS #1** – Port Arthur TS #1 is a 115/25 kV station located in the Thunder Bay Sub-Region and was put in-service in 1950.

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing AC/DC station service systems, 25kV switchyard and associated protection equipment in the new building, and 115 kV associated protection equipment in the existing building

   This project is currently planned to be completed in 2021-2024.

8. **Rabbit Lake SS** – is a 115 kV switching station located in the West of Thunder Bay Sub-Region. The switching station has seven 115 kV transmission lines connecting to three customer generating stations (CGSs) as well as Whitedog Falls SS, Kenora TS, Fort Frances TS, Dryden TS, and the interconnection

with Manitoba Hydro. There are six 115 kV oil circuit breakers and two 115 kV SF6 circuit breakers in the yard.

Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing EOL 115 kV circuit breakers, select switches, and equipment protections.

This project is currently planned to be completed in 2021-2024.

9. **Terrace Bay SS** – is located in the Greenstone-Marathon Sub-Region and was put in-service in 1973. The switching station has two 115 kV transmission lines connecting to Marathon TS and Aguasabon SS. The station is also critical to the connection of a Customer Transformer Station (CTS).

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing protections, controls, telecom, select switches, and AC/DC station service system.

   This project work is currently planned to be completed in 2021-2024

10. **Whitedog Falls SS** – is a 115 kV switching station located in the West of Thunder Bay Sub-Region. The switching station has three 115 kV transmission lines, connecting to Rabbit Lake SS, Caribou Falls GS, and Whitedog Falls GS.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing 115 kV circuit breakers and select switches. In addition, scope of work includes replacing/upgrading of DC station supply system.

    This project is currently planned to be completed in 2021-2024.

11. **Moose Lake TS** – is a 115/44 kV transformer station built in 1948. It is located on Moose Lake near Atikokan in the West of Thunder Bay Sub-Region. Moose Lake TS consists of two non-standard step-down transformers T2 and T3 rated at 8MVA and 15MVA, respectively. In addition, the two transformers are 69 years old.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing the two non-standard power transformers (T2, T3) with standard 110-44 kV, 25/41.7 MVA units, two low voltage oil circuit breakers with new SF6 breakers, and replacing and upgrading the protection, control and AC/DC station service facilities

    This project is currently planned to be completed in 2022-2025

12. **Kenora TS** – is a 230/115 kV station located in the West of Thunder Bay Sub-Region and critical to supply of the city of Kenora and the interconnection with the province of Manitoba.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing/upgrading AC/DC station service systems and replacing protection equipment.

    This project is currently planned to be completed in 2024-2027.

13. **Mackenzie TS** – is a 230/115 kV station is located in the West of Thunder Bay Sub-Region. Mackenzie TS has six 230 kV breakers which are about 46 years old.

Hydro One has planned to replace all EOL equipment at the station. The scope of work involves replacing 230 kV circuit breakers, select protections, and AC/DC station service system.

This project is currently planned to be completed in 2024-2027.

14. **Fort Frances TS** – is located in the Town of Fort Frances and was put in-service in 1947.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing high voltage circuit breakers, replacing/upgrading AC/DC station service system and protection equipment.

    This project is currently planned to be completed in 2025-2028.

15. **Lakehead TS** – is a 230/115 kV transformer station located in the Thunder Bay Sub-Region and was put in-service in 1955. The station is critical to the transmission system of the Northwest and a major hub for East-West power transfer.

    Hydro One has planned to replace all EOL equipment at the station to ensure reliability of the transmission system and supply to the customers. The scope of work involves replacing high voltage circuit breakers with new SF6 breakers, replacing four LV circuit breakers with new SF6 breakers, replacing protection equipment associated with 115 kV facilities and the synchronous condenser, replacing select switches, and replacing/upgrading AC station service system.

    This project is currently planned to be completed in 2025-2028.

16. **Marathon TS** – is a 230/115 kV transformer station, located in the City of Marathon in the Greenstone-Marathon Sub-Region. It was put in-serviced in 1970. The station is critical to the transmission system of the Northwest and a major hub for East-West power transfer. All four 115 kV oil circuit breakers at the station are about 40 years old. Whereas, three 230 kV circuit breaker at the station are about 48 years old.

    Hydro One has planned to replace all EOL equipment at the station to ensure reliability of the transmission system and supply to customers. The scope of work involves replacing three EOL 230 kV circuit breakers with new SF6 breakers, and four EOL 115 kV circuit breakers with new SF6 breakers. In addition, the scope of work also includes replacing disconnect switches, protection equipment, and AC station service system.

    This project is currently planned to be completed in 2025-2028.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast Scenarios

For the purpose of this RIP, the LDCs reviewed their load forecasts and confirmed that they have not changed significantly from the load forecasts reported in the Northwest IRRPs. Based on the load forecasts from the LDCs and the industrial (mining) load forecasts of the Northwest IRRPs, three scenarios of future demand has been considered for each Northwest sub-region in this RIP. Table 5-1, Table 5-2, Table 5-3, and Table 5-4 show the forecasted load for the Low, Medium and High growth scenarios.

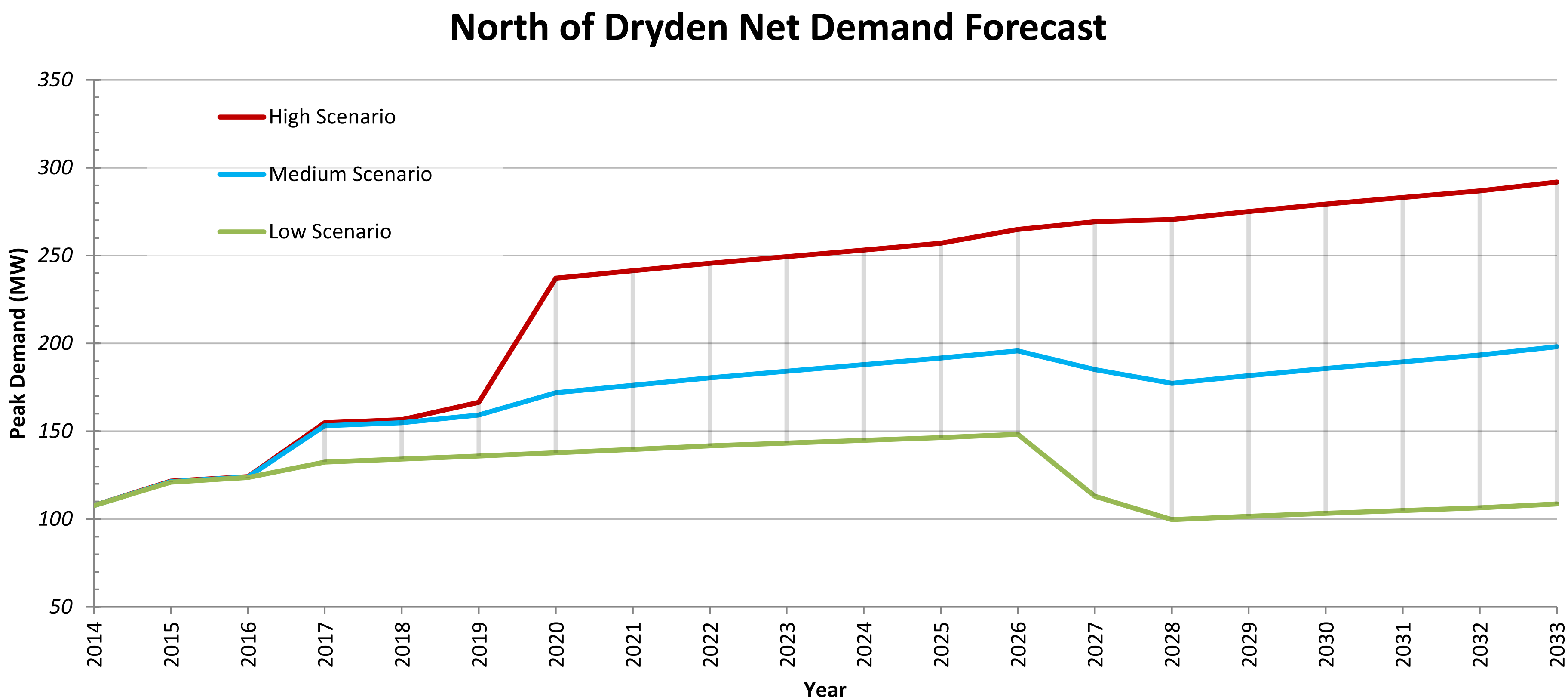
5.2 Other Study Assumptions

The other assumptions made in this RIP report include,

- The study period is 2016-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be available by the specified in-service dates.
- Since in the Northwest region winter peak is more critical than the summer peak, the study is based on winter peak conditions.

Table 5-1 North of Dryden Load Forecast Scenarios

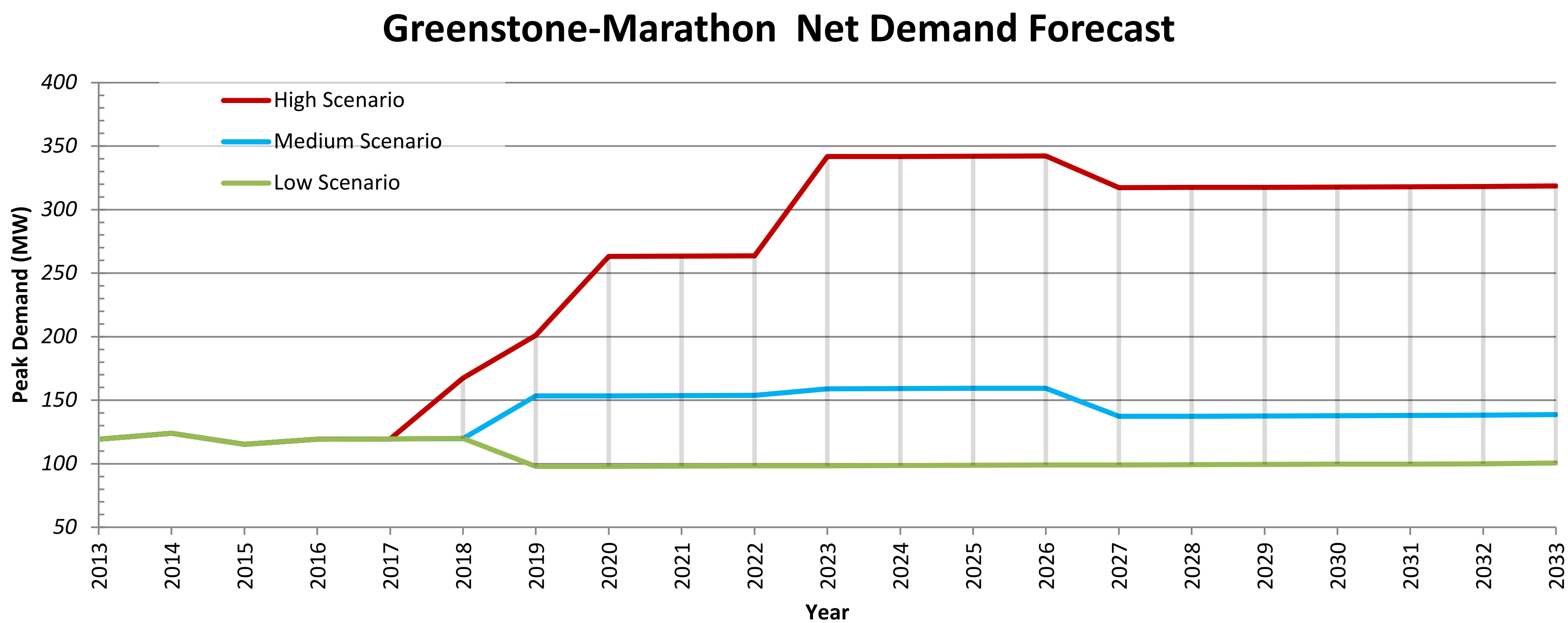
Net Demand Forecast (MW)																				
Scenario	2014 Historic	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Low	107.6	121.1	123.7	132.4	134.1	135.9	137.8	139.7	141.7	143.3	144.8	146.5	148.2	113.0	99.7	101.6	103.3	104.9	106.5	108.7
Medium[5]		121.4	124.0	153.1	154.8	159.3	171.9	176.1	180.3	184.1	187.9	191.7	195.7	185.2	177.3	181.6	185.7	189.5	193.3	198.0
High		121.6	124.2	154.9	156.6	166.5	237.1	241.3	245.5	249.3	253.1	256.9	264.9	269.3	270.6	275.0	279.2	283.1	286.8	291.7



[4] In the North of Dryden IRRP, load forecast starts from year 2015. For consistency, instead of the actual load in 2015 and 2016, the above table shows the IRRP load forecast for these years.
[5] The Medium scenario in the above table corresponds to the Reference scenario in the North of Dryden IRRP

Table 5-2 Greenstone-Marathon Load Forecast Scenarios[7]

Net Demand Forecast (MW)																					
Scenario	**2013 Historical**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Low		124.0	115.2	119.3	119.5	120.0	97.9	97.9	98.2	98.3	98.5	98.6	98.8	99.0	99.1	99.3	99.4	99.6	99.8	100.0	100.6
Medium	119.2	124.0	115.2	119.3	119.5	119.9	153.4	153.4	153.7	153.8	159.0	159.1	159.3	159.5	137.3	137.4	137.6	137.8	137.9	138.1	138.7
High		124.0	115.2	119.3	119.5	167.4	201.0	263.3	263.5	263.6	341.8	341.9	342.1	342.2	317.4	317.5	317.6	317.8	317.9	318.1	318.6

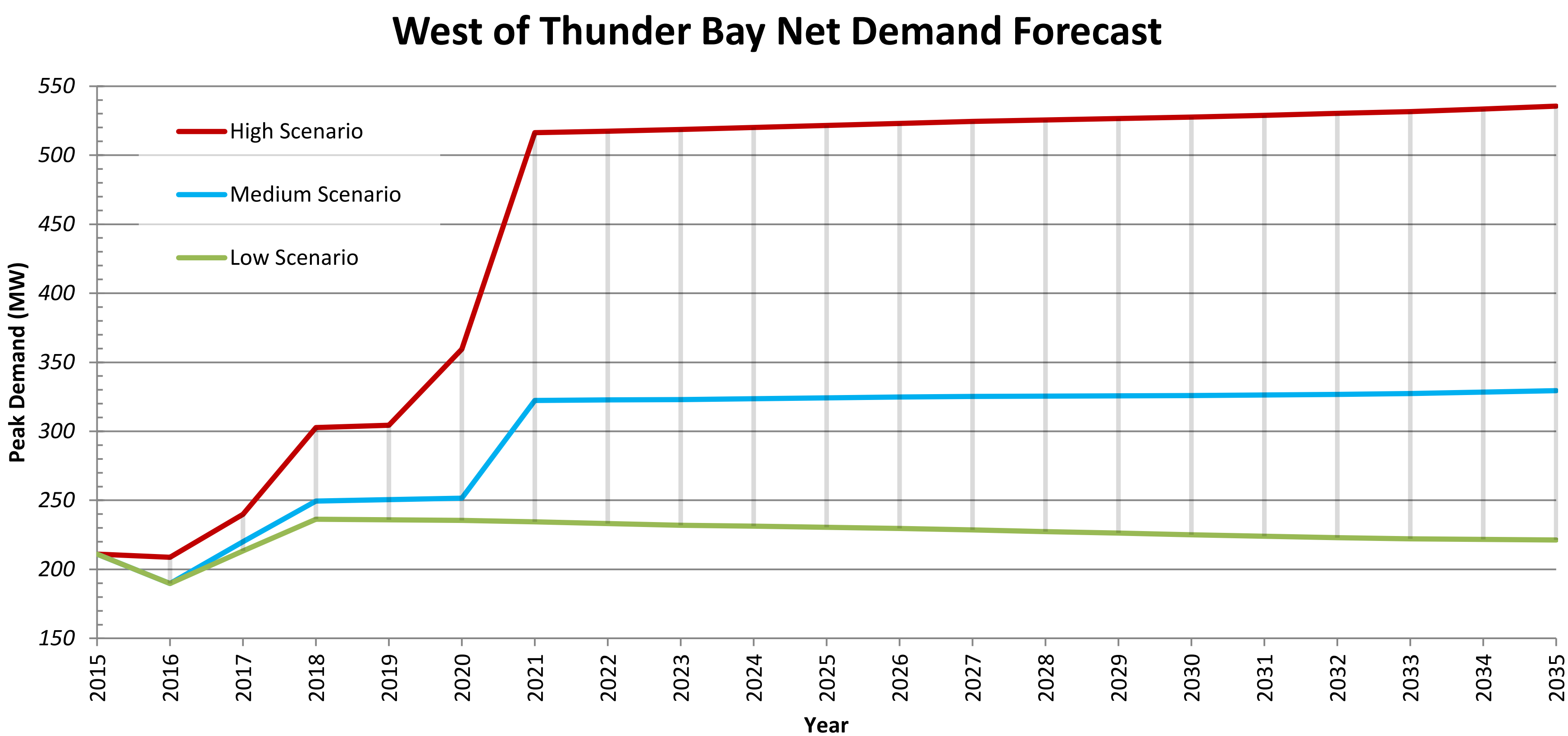


[6] In the Greenstone-Marathon IRRP, load forecast starts from year 2014. For consistency, instead of the actual load in 2014 to 2017, the above table is based on the IRRP load forecast for these years.

[7] . The Low growth scenario for Greenstone-Marathon sub-region corresponds to scenario “A” of the three sub-systems in the IRRP, the Medium growth scenario corresponds to scenario “B” of Greenstone and Marathon and scenario A of Northshore sub-systems in the IRRP, and the High growth scenario corresponds to scenario “D” of Greenstone, scenario “C” of Marathon and scenario “A” of Northshore sub-systems in the IRRP (see section 5 for details of Load Forecast Scenarios).

Table 5-3 West of Thunder Bay Load Forecasts Scenarios

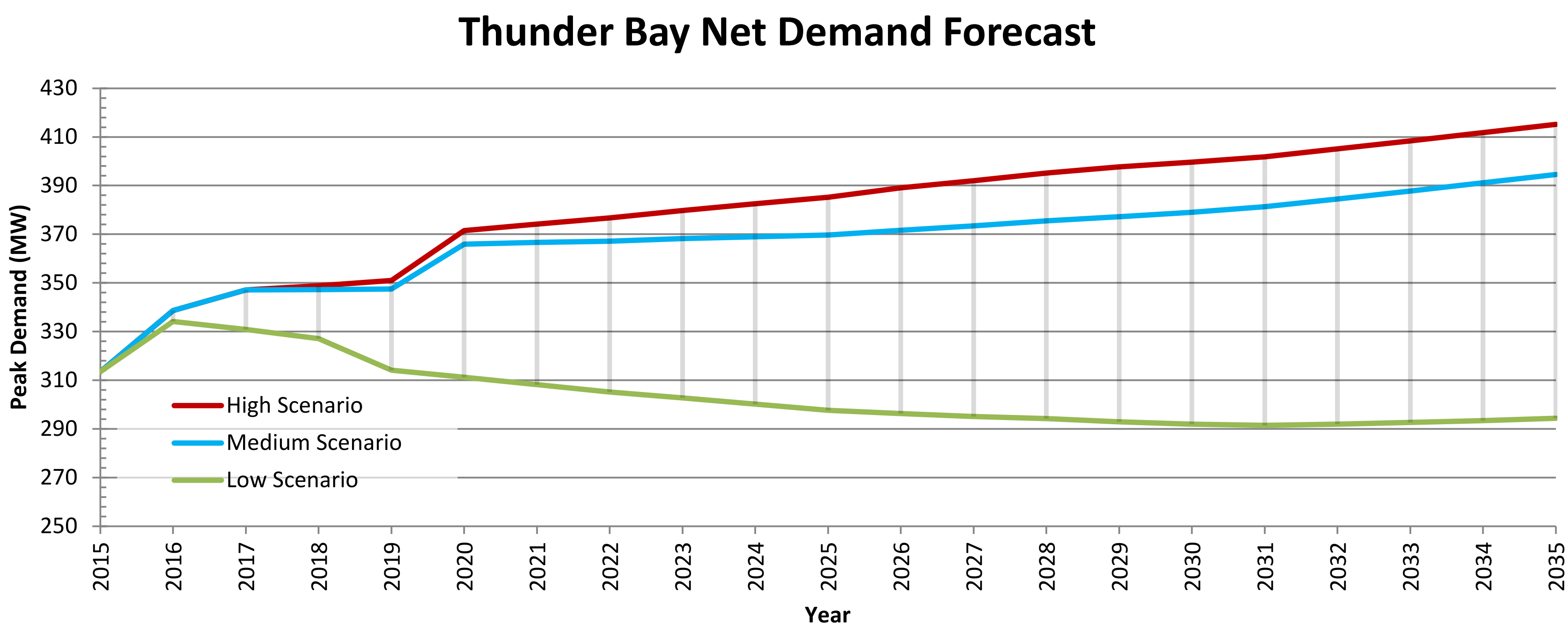
Net Demand Forecast (MW)																					
Scenario	2015 Historical	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low		189.7	213.4	236.3	235.9	235.5	234.4	233.2	232.0	231.2	230.4	229.5	228.6	227.4	226.2	225.0	223.9	223.0	222.1	221.7	221.3
Medium	211.1	189.8	220.1	249.6	250.5	251.6	322.4	322.7	322.9	323.6	324.2	324.8	325.3	325.4	325.7	325.9	326.3	326.8	327.3	328.3	329.4
High		208.8	239.9	302.6	304.5	359.6	516.3	517.4	518.5	520.0	521.5	523.0	524.4	525.4	526.6	527.6	528.9	530.2	531.6	533.5	535.4



[8] In the West of Thunder Bay IRRP, load forecast starts from year 2016. For consistency, instead of the actual load in 2016, the above table shows the IRRP load forecast for this year.

Table 5-4 Thunder Bay Load Forecast Scenarios

Net Demand Forecast (MW)																					
Scenario	2015 Historical	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low	313.6	334.1	330.9	327.1	314.2	311.2	308.2	305.1	302.7	300.2	297.6	296.4	295.1	294.2	292.9	292.0	291.5	292.0	292.6	293.4	294.3
Medium		338.7	347.1	347.3	347.5	365.9	366.7	367.1	368.2	369.0	369.7	371.6	373.4	375.5	377.1	379.0	381.3	384.5	387.8	391.2	394.6
High		338.7	347.1	348.8	351.0	371.5	374.2	376.7	379.7	382.5	385.2	389.1	391.9	395.1	397.7	399.6	401.9	405.1	408.4	411.7	415.1



[9] In the Thunder Bay IRRP, load forecast starts from year 2016. For consistency, instead of the actual load in 2016, the above table shows the IRRP load forecast for this year.

6. SUMMARY OF REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES THE WIRE NEEDS FOR THE NORTHWEST ONTARIO REGION AND SUMMARIZES THE RECOMMENDED WIRES PLANS FOR ADDRESSING THE NEEDS.

This section provides a summary of the needs and plans for the four Northwest sub-regions. The load forecasts from the LDCs have not materially changed since the completion of the previous phase (IRRP) of Regional Planning for the Northwest. Therefore, the assumptions and load growth scenario for industrial loads, as well as the needs and plans identified in this RIP are consistent with the Northwest IRRPs. The needs and recommended plans in the region are largely driven by the industrial load growth, particularly the mining sector. Proceeding to the Development phase of the customer-driven projects requires formal request by the customers and commercial agreements between Hydro One and the customers.

6.1 North of Dryden Sub-Region

Most of the demand in the North of Dryden sub-region is from the mining sector. The demand growth is driven by the expansion of this sector, as well as the connection of up to 21 remote communities in the northern parts of the region to Red Lake and Pickle Lake and growth in the mining sector, including potential developments in the Ring of Fire which may be supplied from Pickle Lake.

The North of Dryden IRRP [2] for this sub-region has assumed Low, Medium (referred to as Reference in IRRP [2]) and High load growth scenarios. Based on these scenarios, it has identified the needs and recommended wires plans in near-term, mid-term and long-term. The following are summaries of the needs and recommended plans for this sub-region, which consists of Pickle Lake sub-system, Red Lake sub-system, and Ring of Fire sub-system.

6.1.1 Pickle Lake Needs and Recommended Plans

The North of Dryden IRRP [2] has identified that the existing single supply to Pickle Lake, i.e. the 115 kV circuit E1C, is serving 24 MW of load and is at its capacity. Any load growth in the near-term from the existing mine or connection of remote communities will require increase of LMC. The additional capacity needs, based on the medium (reference) load growth scenario are 18 MW, 28 MW and 47 MW in near-term, mid-term and long-term, respectively.

Pickle Lake LMC is limited by voltage stability. Providing dynamic voltage support, e.g. installing Static VAR Compensator (SVC) at Pickle Lake offers moderate increase in LMC, assuming the remaining capacity of circuit E4D will be available for this load increase. One alternative assessed in the IRRP is to install a new 115 kV single-circuit line from Valora, south of Dryden, to Pickle Lake to provide additional LMC that meets the near-term needs of Pickle Lake and releases some capacity on circuit E4D. However, in the long-term, with the development of new mines and potential for connection of the Ring of Fire to Pickle Lake (one the alternatives identified in the IRRP), an increase of over 130 MW in LMC may be required under the high growth forecast. As a result, the recommendation is to proceed with a plan required to meet the needs of the medium (reference) and high growth scenarios in the long-term. This plan can make the full capacity of circuit E4D available to serve the Red Lake sub-system.

<u>Recommended Plan:</u>

- Install a new 230 kV transmission line to Pickle Lake from either the Dryden area (e.g. Dinorwic) or Ignace area;

- Install a new 230 kV switching station to connect the new line to the existing circuits D26A;
- Install a new 230/115 kV auto-transformer at the end of the new line in Pickle Lake;
- Install new 115 kV switching facilities (circuit breakers) to connect the existing circuit E1C, existing customers at Pickle Lake and the new connections of the remote communities to the new auto-transformer; and
- Install required reactive compensation for voltage control

An Order in Council from the government, dated July 20, 2016, has directed the OEB to amend Wataynikaneyap Power LP's (Wataý Power) licence for Wataý Power to develop and seek approvals for the Line to Pickle Lake and the connection of sixteen remote communities. Wataý Power has initiated the Development phase of the project for these connections. Currently the planned in-service date of the 230 kV line to Pickle Lake is Q2 2020, based on Wataý Power's active connection assessment with the IESO.

6.1.2 Red Lake Needs and Recommended Plans

The North of Dryden IRRP [2] has identified that the current LMC of 61 MW at Red Lake, supplied by circuits E2R and E4D, is insufficient to meet the needs of the mining load, based on the expected growth at this location, even in near-term. The additional capacity needs, based on the medium (reference) load growth scenario are 30 MW, 44 MW and 48 MW in near-term, mid-term and long-term, respectively. Additional capacity needs increase to 75 MW under high load growth scenario.

The wires plans to meet the near-term needs are the following.

Recommended Plan:

- Upgrade circuit E4D to a summer rating of 660 A
- Upgrade circuit E2R to a summer rating of 610 A
- Provide additional voltage control at Ear Falls and/or Red Lake

However, since the load increase in the mining sector has not materialized at the same pace as previously anticipated, the initial plans for the upgrade of circuits E4D and E2R have been put on hold, awaiting customer request. A recent System Impact Assessment by the IESO for a load increase at Red Lake has determined that although the existing system can meet the demand, circuit E4D is reaching its thermal limit. Therefore, the above plan for the upgrade of circuit E4D (and E2R) can proceed in case of a request by, and agreement with, customers for additional load. Alternatively, operating measures can be used until additional firm capacity becomes available in the mid-term.

In the mid/long-term, assuming that the planned 230 kV line to Pickle Lake (see the previous section) is completed, which can make the full capacity of circuit E4D available to serve the Red Lake sub-system, there will be sufficient capacity to meet the needs under medium (reference) and high load growth scenarios. Only if the needs exceed the high growth forecast of this planning horizon, or the planned 230 kV line to Pickle Lake is not completed, a new 115 kV or 230 kV line from Dryden to Ear Falls will be one of the alternatives for meeting the demand.

6.1.3 Ring of Fire Sub-system Needs and Potential Options

The North of Dryden IRRP [2] has indicated that as the Ring of Fire sub-system is remote from the existing transmission system, any additional capacity needs would require new facilities. The IRRP has also indicated that transmission supply is the most economic option under all of the forecast scenarios, which considers the five remote communities in the vicinity of the Ring of Fire that have been identified as being economic to connect in the IESO's Remote Community Connection Plan [6] as well as possible mining customers. If mining load does not fully materialize, the North of Dryden IRRP [2] concluded that an east-west supply from the Pickle Lake area was the most economic option. If mining load fully materializes, the IRRP concluded that the economic option is either an east-west supply from the Pickle Lake area or a north-south supply from a point along the East-West Tie. Development in the area is still at an early stage and no firm recommendations can be made at this time.

6.2 Greenstone-Marathon Sub-Region:

The identified needs and recommended wire plans for this sub-region are directly related to a few large industrial developments. Based on the current load meeting capability (LMC) of the sub-region, all circuits except circuit A4L in Greenstone-Marathon sub-region are adequate to meet the projected demand forecast under all scenarios during the planning cycle. Circuit A4L is also adequate under the low demand scenario. The IRRP report [3] has recommended near term (present-5 years), medium term (5-10 years) and long term (10-20 years) actions to address the A4L limitations under the medium and high demand scenarios as described below.

6.2.1 Low Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, Low Scenario assumptions are as follows:

- Hydro One Distribution customer growth
- Two saw mill re-starts

The existing circuits have sufficient LMC to meet Low Scenario's forecasted demand.

No wire plans are required for this scenario.

6.2.2 Medium Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, Medium Scenario assumptions are as follows:

- Low Scenario assumptions
- Development of Geraldton mine
- Development of Beardmore mine
- Life extension of the existing Marathon Area mine

Under this scenario, the needs and recommended wires plans are the following.

Accommodate Geraldton mine – Increase Circuit A4L Capacity:

Single-circuit 115 kV line A4L runs from Alexander SS to Longlac TS. A mining development in Geraldton area, with the proposed in-service date of 2019, would increase the near-term demand on circuit A4L to 51 MW, which is higher than its current LMC of approximately 25 MW. The LMC of circuit A4L is limited by voltage.

A major deciding factor in the recommendation for meeting the forecasted demand is the lead time relative to the proposed timelines for the mine development.

<u>Recommended Plan:</u>

If the proposed in service date of 2019 does not change, Installing Reactive Compensation and gas-fired generation in the near term is the recommended solution.

Installing reactive compensation of about +40 MVARs in the form of either synchronous condenser or Static Synchronous Compensators (STATCOM) at the Geraldton mine site would increase the LMC of circuit A4L to 45 MW, making full thermal capability of the circuit available. This form of Reactive Compensation is recommended considering the low short-circuit level at the end of circuit A4L relative to the requirements of the mine. The remaining short fall of approximately 6 MW to meet the needs of the mine can be provided by a customer-based grid-connected gas-fired generation plant with sufficient redundancy, for example, installing two 10 MW gas-fired units.

If the in-service date of the mine is delayed, replacing a section of circuit A4L, between Nipigon and Longlac, along with the installation of the above reactive compensation, would increase the LMC of circuit A4L to about 60 MW. Replacing the section of circuit A4L has a lead time of approximately five years.

Accommodate Beardmore mine – Increase Circuit A4L Capacity

A potential gold mine near Beardmore may be operational within the medium term. If Geraldton mine doesn't connect to circuit A4L as described above, the existing system would be sufficient to support the Beardmore mine.

If the Geraldton mine connects to circuit A4L and the plans for the high-demand scenario (described below) do not proceed, in order to accommodate the Beardmore mine, additional capacity would be required.

Recommended Plan:

Upgrading a section of circuit A4L from Alexander SS to Beardmore Junction is a medium term wires option for supplying the potential mine.

6.2.3 High Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, High Scenario assumptions are as follows

- Medium Scenario assumptions
- Development of the proposed Energy East pipeline
- Development of additional mines in Marathon Area
- Development of Ring of Fire, with connection to the Greenstone area

Under this scenario, the needs and recommended wires plans are the following.

Accommodate Energy East Pipeline and, potentially, the Ring of Fire – Install New Wires:

Potential Energy East load is subjected to customers' request for connection of the pumping stations to the provincial electricity grid. The medium or long term recommended plans for the High Scenario depend on the Energy East plans and timelines for connecting some or all of the pumping stations, in one or two phases.

The Greenstone-Marathon Sub-Region IRRP [3] also indicates that the Ring of Fire could be potentially connected by an east-west corridor to Pickle Lake or by a north-south corridor to the Nipigon or Marathon areas.

Recommended Plan:

According to the IRRP report [3], the preferred option under the High Scenario, with or without the potential connection of the Ring of Fire, is the following wires plan.

- Install a new 230 kV transmission line to Longlac TS from either from the Nipigon area or from the Marathon (or Terrance Bay) area;
- Install a new 230 kV switching station to connect the new line to the existing circuits M23L-M24L;
- Install a new 230/115 kV auto-transformer at Longlac TS;

- Install required reactive compensation for voltage control and short-circuit level requirements at the mine; and
- Install a new 115 kV Line from Longlac TS to Manitouwadge TS to supply all the pumping stations in the area, possibly in the second phase.

Advancing the plan for the new transmission line and transformer, in order to meet the timelines of the Geraldton mine and the Beardemore mine developments, is an alternative to the upgrade of circuit A4L described under the Medium Scenario above. During outages of the new line or transformer, the new mines and industrial loads need to be interrupted to maintain the loading on circuit A4L below its LMC.

The above plan will improve the reliability for the customers served from Longlac TS by maintaining their supply through the new transmission line and transformer during outages of circuit A4L.

6.3 West of Thunder Bay Sub-Region

This sub-region, as described in the IRRP report [4], consists of four main sub-systems, Moose Lake, Fort Frances, Kenora and Dryden. The West of Thunder Bay Sub-Region is also a source of supply to the North of Dryden sub-region (through the Dryden 115 kV system) and therefore the needs and recommendations from the North of Dryden IRRP (described in the previous sections) were considered in the West of Thunder Bay IRRP.

Similar to the other sub-regions described above, because of the uncertainty in the development plans and connection options, the IRRP has considered low, medium (or reference) and high load growth scenarios in the West of Thunder Bay sub-region and has identified near/mid/long-term needs and recommendations for each scenario.

The low load growth scenario has forecasted a peak demand of close to 240 MW in 2017 (with the startup of a new mine near Rainy River) which will remain fairly flat until 2034.

In the medium load growth scenario, involving new mines and industrial load (pumping stations of the pipeline conversion project), the load forecast increases from 252 MW in 2017 to 345 MW in 2034.

In the high load growth scenario, involving additional mines, the load forecast increases from 305 MW in 2017 to 551 MW in 2034.

6.3.1 Dryden Needs and Plans

The Dryden 115 kV sub-system can provide up to 240 MW of continuous supply to the Dryden and North of Dryden Sub-Region. Under the low and medium (reference) load growth scenarios, this LMC is sufficient to meet the demand of this sub-system.

Under the high load growth scenario, additional capacity of 50 MW will be required on the 115 kV system at Dryden by the mid-2020s. This scenario considers high growth in the North of Dryden Sub-Region, and assumes that all load on circuit E1Cwill be supplied by the proposed 230 kV line to Pickle Lake. The IRRP identified one option for meeting the need of the 115 kV system to install a third autotransformer at Dryden TS. A recommended plan has not been finalized at this time given the long lead time and uncertainty associated with potential developments in the area. The next cycle of Regional Planning will reassess the need.

6.3.2 Kenora Needs and Plans

The transformer station supplying the City of Kenora and surrounding areas ("Kenora MTS") can supply 25 MW. This transformer station currently supplies up to 20 MW. Since the increase in the residential and commercial load in the Kenora area is forecast to be modest over the planning period, the remaining 5 MW margin will be adequate for the Kenora area.

The IRRP has identified that an industrial customer, currently supplied by a local generating station is considering pursuing an alternative supply arrangement from Kenora MTS. Furthermore, potential developments at the former Abitibi mill site may also require additional transformer station capacity in the Kenora area. The magnitude and timing of these developments remains uncertain and is not expected to have major regional implications. No actions were recommended in the IRRP to address the need at this time.

6.3.3 Moose Lake Needs and Plans

The Moose Lake 115 kV sub-system has sufficient supply capacity to meet demand in the planning horizon under each load growth scenario. Therefore, no actions were recommended in the IRRP at this time.

6.3.4 Fort Frances Needs and Plans

The Fort Frances 115 kV sub-system was found to have sufficient supply capacity to meet demand in the planning horizon under each load growth scenario. Therefore, no actions were recommended in the IRRP at this time.

6.4 Thunder Bay Sub-Region

The IRRP for the Thunder Bay sub-region [5] considered low, medium and high load growth scenarios and identified near/mid/long-term needs and recommendations for each scenario. The assessments of this sub-region have assumed that the most impactful scenario in the Greenstone sub-system will materialize, resulting in 60 MW supply need from the Thunder Bay sub-region (i.e. on circuit A4L in case it would be upgraded).

The low load growth scenario has forecast the peak demand of close to 325 MW in 2015 will decline to about 300 MW by 2035 as a result of continuing decline in the pulp and paper sector and without new mining or industrial developments in Thunder Bay.

In the medium load growth scenario, involving new mines and industrial load (one pumping station of the Energy East gas-to-oil pipeline development supplied from the Thunder Bay transmission system) and no change in the pulp and paper sector, the load is forecasted to increase to 400 MW in 2035. This is comparable to the sub-region's historic peak demand in 2006/2007.

In the high load growth scenario, involving additional transmission connected mining developments north of Thunder Bay; the load is forecasted to increase to 415 MW by the end of planning period.

In addition to the potential long-term wires options for medium/high growth scenarios described below, the IRRP for Thunder Bay sub-region identified the near-term need for upgrading the thermal rating of circuit R2LB between Lakehead TS and Birch TS to that of the companion circuit R1LB. This work has been completed.

6.4.1 Long-Term Needs and Plans

Port Arthur TS - Transformation Capacity

The long-term load forecast indicates that the demand from the customers supplied by Port Arthur TS will exceed the station's current capacity by 2033, and additional station capacity will be required if this load growth materializes.

Currently, the low voltage equipment at Port Arthur TS are limiting the station capacity to 55 MW. The station transformers provide up to 59 MW of capacity.

<u>Wires Option:</u>

The low voltage equipment, which are limiting the station capacity are nearing end-of-life and are planned to be replaced and upgraded in mid-term. This upgrade would bring the station capacity up to 59 MW, sufficient to meet the need beyond 2035. No additional plan is required at this time and load at Port Arthur TS will be monitored and supply options will be assessed in the next cycle of Regional Planning.

Lakehead TS and Birch TS - Transformation Capacity

Currently the Thunder Bay 115 kV system can accommodate approximately 150 MW of additional load growth. This capacity is sufficient under the low and medium load growth scenarios in the long-term.

Under the High growth scenario, and assuming the most impactful Greenstone sub-system scenario (60 MW, as described above), the Thunder Bay system would require additional supply capacity of approximately 20 MW by 2030.

The Thunder Bay IRRP indicates that a firm plan to increase the LMC of the Thunder Bay 115 kV system is not required at this time, as the large margin remaining on the system provides significant lead time for the Working Group to monitor demand growth and study options. The IRRP report explored various wires and non-wires options as potential long term solutions to increase the LMC of the system, however no action beyond monitoring is recommended at this time.

The wires options discussed in the Thunder Bay IRRP are described below:

1. Installing a third 230/115 kV 250 MVA autotransformer at Lakehead TS to increase the LMC of Lakehead TS by approximately 240 MW.

2. A new 230 kV line from Lakehead TS to Birch TS and a 230 kV 250 MVA autotransformer at Birch TS to create a supply point for the southern part of Thunder Bay, with a supply capacity of 240 MW. The new 230 kV line would require a new Right-of-Way and would take 5 years or longer to build.

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7. CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE NORTHWEST ONTARIO REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This section provides a summary of the Needs and Plans for the Northwest Region as identified in this RIP.

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

North of Dryden Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
1	Circuits E1C and E4D Capacity	A 230 kV transmission line from Dryden/Ignace area to Pickle Lake	Medium[1]	Near-term	Recommended in IRRP. Development has started.
2	Circuits E4D and E2R Capacity	Upgrade of transmission lines E2R and E4D, and additional voltage support	All Scenarios	Near-term	Recommended in IRRP. The need has not materialized.
3		A 115 kV or 230 kV transmission line from Dryden to Ear Falls	High	Long-term	Proposed in IRRP. Not needed in the planning horizon, assuming Projects 1 and 2 proceed.

Greenstone-Marathon Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
4	Circuit A4L Capacity	Upgrade of sections of transmission line A4L, and dynamic voltage support devices at Geraldton	Medium[2]	Near-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Geraldton mine.
5		Upgrade of other sections of transmission line A4L	Medium[2]	Mid-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Beardmore mine.
6	Capacity for Pipeline Project and Ring of Fire	A 230 kV transmission line from Nipigon or Terrace Bay to Geraldton, and voltage support devices	High[2]	Mid/Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of pipeline loads and mines.
7		A 115 kV transmission line from Manitouwadge to Geraldton, and voltage support devices	High[2]	Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of additional pipeline loads.

West of Thunder Bay Sub-Region Wires Plans					
No.	**Need**	**Wires Options**	**Load Growth**	**Term**	**Status**
8	Dryden 115 kV System Capacity	A 230/115 kV auto-transformer in Dryden area	High	Mid-term	Proposed in IRRP. Next planning cycle will reassess the need.

Thunder Bay Sub-Region Wires Plans					
No.	**Need**	**Wires Options**	**Load Growth**	**Term**	**Status**
9	Thunder Bay 115 kV System Capacity	A 230/115 kV auto-transformer in Thunder Bay area	High	Long-term	Proposed in IRRP. Next planning cycle will reassess the need.
10	Port Arthur TS Transformation Capacity	Upgrade of Low-Voltage equipment at Port Arthur TS	All Scenarios	Long-term	Proposed in IRRP. LV equipment are planned for End-of-Life replacement in mid-term. Next planning cycle will reassess the need.

8. REFERENCES

[1]. Northwest Region Scoping Assessment (SA) Outcome Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Final_Northwest_Scoping_Process_Outcome_Report.pdf

[2]. North of Dryden Sub-Region Integrated Regional Resource Plan (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/North_of_Dryden/North-Dryden-Report-2015-01-27.pdf

[3]. Greenstone-Marathon Sub-Region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Greenstone_Marathon/2016-Greenstone-Marathon-IRRP-Report.pdf

[4]. West of Thunder Bay Sub-Region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/West_of_Thunder_Bay/2016-West-of-Thunder-Bay-IRRP.pdf

[5]. Thunder Bay Sub-Region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Thunder-Bay-IRRP.pdf

[6]. 2014 Draft Remote Community Connection Plan
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Remote_Community/OPA-technical-report-2014-08-21.pdf

Appendix A. Stations in the Northwest Ontario Region

Sub-Region	Station	Voltage (kV)	Supply Circuits
North of Dryden	Ear Falls TS	115/44	M3E, E4D, E1C, E2R
	Red Lake TS	115/44	E2R
	Cat Lake MTS	115/25	E1C
	Crow River DS	115/25	E1C
	Perrault Falls DS	115/12.5	E4D
	Slate Falls DS	115/24.9	E1C
Greenstone-Marathon	Longlac TS	115/44	A4L
	Manitouwadge TS	115/44	M2W
	Marathon TS	230/115	T1M, W21M, M23L, M2W, M24L, W22M
	Beardmore DS #2	115/25	A4L
	Jellicoe DS #3	115/12.5	A4L
	Manitouwadge DS #1	115/12.5	M2W
	Marathon DS	115/25	T1M
	Pic DS	115/25	M2W
	Schreiber Winnipeg DS	115/12.5	A5A
	White River DS	115/25	M2W
West of Thunder Bay	Barwick TS	115/44	K6F
	Dryden TS	230/115	K3D, D26A, E4D, D5D, K23D, M2D
	Fort Frances TS	232/115	K24F, F25A, K6F, F1B, F2B, F3M
	Kenora TS	230/115	K24F, K7K, K21W, K23D, K22W
	Mackenzie TS	230/115	D26A, A22L, A3M, F25A, A21L, N93A
	Moose Lake TS	115/44	A3M, M1S, M2D, B6M
	Fort Frances MTS	115/12.47	F1B
	Kenora MTS	115/12.5	15M1
	Agimak DS	115/25	29M1
	Burleigh DS	115/12.5	F1B
	Clearwater Bay DS	115/25	SK1
	Eton DS	115/12.48	K3D
	Keewatin DS	115/12.5	SK1
	Margach DS	115/25	K6F
	Minaki DS	115/25	K4W
	Nestor Falls DS	115/13.2	K6F
	Sam Lake DS	115/26.4	K3D
	Sapawe DS	115/12.5	B6M
	Shabaqua DS	115/12.5	B6M
	Sioux Narrows DS	115/12.5	K6F
	Valora DS	115/25	29M1
	Vermilion Bay DS	115/12.5	K3D
Thunder Bay	Birch TS	115/28.4	Q9B, P7B, Q8B, Q5B, R2LB, P3B, Q4B, R1LB, B6M
	Fort William TS	115/25	Q5B, Q4B
	Lakehead TS	230/115	A22L, M23L, A21L, R2LB, L4P, M24L, A7L, R1LB, A8L, L3P
	Port Arthur TS #1	115/25	P7B, P1T, A6P, L4P, P3B, P5M, L3P
	Murillo DS	115/26.40	B6M
	Nipigon DS	115/4.16	57M1
	Red Rock DS	115/12.5	56M1

Appendix B. Transmission Lines in the Northwest Ontario Region

Circuit(s)	Location	Voltage (kV)
D26A	Mackenzie x Dryden	230
F25A	Mackenzie x Fort Frances	230
K23D	Dryden x TCPL Vermill Bay x Kenora	230
K24F	Fort Frances x Kenora	230
N93A	Mackenzie x Marmion Lake x Atikokan	230
K21W, K22W	Kenora x Whiteshell (Manitoba Hydro)	230
A21L, A22L	Mackenzie x Lakehead	230
M23L, M24L	Marathon x Lakehead	230
15M1	Kenora x Rabbit Lake	115
29M1	Ignace x Camp Lake x Valora x Mattabi	115
A3M	Mackenzie x Moose Lake	115
B6M	Moose Lake x Sapawe x Shabaqua x Stanley x Murillo x Birch	115
D5D	Dryden x Domtar Dryden	115
F1B	Fort Frances x Burleigh	115
F3M	Fort Frances x Internat Fls (Minnesota Power)	115
K2M	Kenora x Norman	115
K3D	Dryden x Sam Lake x Eton x Vermilion Bay x Rabbit Lake	115
K4W	White Dog x Minaki x Rabbit Lake	115
K6F	Fort Frances x Ainsworth x Nestor Falls x Sioux Narrows x Rabbit Lake	115
K7K	Kenora x Weyerhaeuser Ken x Rabbit Lake	115
M1S	Moose Lake x Valerie Falls x Mill Creek	115
M2D	Moose Lake x Ignace x Dryden	115
SK1	Rabbit Lake x Keewatin x Forgie	115
W3C	White Dog x Caribou Falls	115
56M1	Nipignon x Red Rock	115
57M1	Reserve x Nipignon	115
A6P	Alexander x Port Arthur	115
L3P, L4P	Lakehead x Port Arthur	115
P3B, P7B	Port Arthur x Birch	115
P5M	Port Arthur x Conmee	115
Q4B, Q5B, Q8B, Q9B	Thunder Bay x Birch	115
R1LB, R2LB	Lakehead x Pine Portage x Birch	115
S1C	Silver Falls x Lac Des Iles x Conmee	115
A1B	Aguasabon x Terrace Bay	115
A4L	Alexander x Nipignon x Beardmore x Jellicoe x Roxmark x Longlac	115
A5A	Alexander x Minnova x Schreiber x Aguasabon	115
C1A, C2A, C3A	Alexander x Cameron Falls	115
GA1	Upper White River x Lower White River	115
M2W	Marathon x Black River x Umbata Falls x Hemlo Mine x White River	115
R9A	Alexander x Pine Portage	115
E1C	Ear Falls x Selco x Slate Falls x Cat Lake x Crow River x Musselwhite	115
E2R	Ear Falls x Balmer x Red Lake	115
E4D	Ear Falls x Scout Lake x Dryden	115
M3E	Manitou Falls x Ear Falls	115
T1M	Terrace Bay x Marathon	115

Appendix C. Distributors in the Northwest Ontario Region

Distributor Name	Station Name	Connection
ATIKOKAN HYDRO INC.	Moose Lake TS	Tx
FORT FRANCES POWER CORPORATION	Fort Frances MTS	Tx
HYDRO ONE NETWORKS INC.	Agimak DS	Tx
	Aguasabon GS	Tx
	Barwick TS	Tx
	Beardmore DS #2	Tx
	Burleigh DS	Tx
	Cat Lake MTS	Tx
	Clearwater Bay DS	Tx
	Crow River DS	Tx
	Dryden TS	Tx
	Ear Falls DS	Tx
	Ear Falls TS	Tx
	Eton DS	Tx
	Fort Frances TS	Tx
	H2O Pwr SturgFls CGS	Tx
	Jellicoe DS #3	Tx
	Keewatin DS	Tx
	Kenora DS	Tx
	Longlac TS	Tx
	Manitouwadge DS #1	Tx
	Manitouwadge TS	Tx
	Marathon DS	Tx
	Margach DS	Tx
	Minaki DS	Tx
	Murillo DS	Tx
	Nestor Falls DS	Tx
	Nipigon DS	Tx
	Perrault Falls DS	Tx
	Pic DS	Tx
	Port Arthur TS #1	Tx
	Red Lake TS	Tx
	Red Rock DS	Tx
	Sam Lake DS	Tx
	Sapawe DS	Tx
	Schreiber Winnipg DS	Tx
	Shabaqua DS	Tx
	Sioux Narrows DS	Tx
	Slate Falls DS	Tx
	Valora DS	Tx
	Vermilion Bay DS	Tx
	White River DS	Tx
	Whitedog Falls GS	Tx
	Whitedog DS	Tx
KENORA HYDRO ELECTRIC CORPORATION	Kenora MTS	Tx
SIOUX LOOKOUT HYDRO INC.	Sam Lake DS	Dx
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	Birch TS	Tx
	Fort William TS	Tx
	Port Arthur TS #1	Tx

Appendix D. Northwest Ontario Stations Non Coincident Load Forecast (2016-2025)

Table D-1 Stations Non Coincident Net Load Forecast (MW)

Station LDCs
Atikokan Hydro
Fort Frances Power Corp
Kenora Hydro
Thunder Bay Hydro
Hydro One Distribution

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
West of Thunder Bay	*Moose Lake TS*	Non Coincidental Gross						6.10	6.16	6.22	6.28	6.35	6.38	6.41	6.44	6.48	6.51
		CDM						0.04	0.07	0.12	0.17	0.21	0.24	0.28	0.31	0.33	0.37
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.50	4.30	4.53	4.93	6.06	6.06	6.09	6.10	6.11	6.14	6.13	6.13	6.13	6.14	6.13
West of Thunder Bay	*Fort Frances MTS*	Non Coincidental Gross						17.10	17.02	16.93	17.10	17.27	17.45	17.62	17.80	17.97	18.15
		CDM						0.11	0.18	0.32	0.46	0.56	0.66	0.76	0.85	0.92	1.03
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	16.93	16.29	17.17	17.92	16.79	16.99	16.83	16.61	16.64	16.70	16.78	16.85	16.95	17.05	17.11
West of Thunder Bay	*Fort Frances TS*	Non Coincidental Gross						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	15.60	16.37	16.73	16.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West of Thunder Bay	*Barwick TS*	Non Coincidental Gross						17.07	17.07	17.29	17.56	17.69	17.81	17.93	18.04	18.19	18.33
		CDM						0.11	0.19	0.32	0.47	0.58	0.68	0.78	0.86	0.93	1.04
		DG						1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Non Coincidental Net					14.00	15.96	15.88	15.96	16.08	16.11	16.13	16.15	16.18	16.25	16.28
West of Thunder Bay	*Kenora MTS*	Non Coincidental Gross						21.45	21.66	21.88	22.10	22.10	22.32	22.32	22.54	22.76	22.99
		CDM						0.14	0.24	0.41	0.59	0.72	0.85	0.97	1.07	1.17	1.31
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	20.49	20.77	21.27	21.62	20.57	21.30	21.41	21.46	21.49	21.37	21.46	21.34	21.45	21.58	21.66
Thunder Bay	*Birch TS*	Non Coincidental Gross						77.88	78.54	78.80	79.31	79.81	80.32	80.55	81.34	81.96	82.52
		CDM						0.51	0.85	1.48	2.13	2.60	3.06	3.50	3.87	4.21	4.70
		DG						0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
		Non Coincidental Net	70.48	70.02	86.01	87.04	74.01	77.33	77.64	77.28	77.14	77.17	77.22	77.01	77.43	77.71	77.77

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Thunder Bay	*Fort Williams TS*	Non Coincidental Gross						77.90	78.14	80.46	81.23	83.61	87.49	91.88	91.11	89.64	89.29
		CDM						0.51	0.85	1.51	2.18	2.73	3.33	3.99	4.33	4.60	5.09
		DG						4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45
		Non Coincidental Net	74.99	73.18	80.22	80.81	79.20	72.94	72.84	74.50	74.59	76.43	79.70	83.44	82.33	80.59	79.76
Thunder Bay	*Port Arthur TS#1*	Non Coincidental Gross						37.00	37.40	37.90	38.50	39.10	39.60	40.20	40.90	41.50	42.20
		CDM						0.24	0.41	0.71	1.03	1.27	1.51	1.74	1.94	2.13	2.40
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	34.92	35.73	35.36	39.98	30.70	36.74	36.98	37.18	37.45	37.81	38.08	38.44	38.94	39.36	39.78
Thunder Bay	*Port Arthur TS #1*	Non Coincidental Gross						8.54	8.65	8.77	8.80	8.94	9.10	9.19	9.28	9.36	9.44
		CDM						0.06	0.09	0.16	0.24	0.29	0.35	0.40	0.44	0.48	0.54
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	8.12	7.48	8.52	8.52	7.90	8.49	8.56	8.60	8.56	8.65	8.76	8.79	8.84	8.88	8.90
West of Thunder Bay	*Agimak DS*	Non Coincidental Gross						3.32	3.33	3.39	3.46	3.50	3.53	3.57	3.60	3.65	3.69
		CDM						0.02	0.04	0.06	0.09	0.11	0.13	0.15	0.17	0.19	0.21
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.96	3.04	3.24	3.70	4.30	3.30	3.30	3.33	3.36	3.38	3.40	3.41	3.43	3.46	3.48
Greenstone-Marathon	*Beardmore DS #2*	Non Coincidental Gross						1.23	1.23	1.25	1.28	1.29	1.30	1.31	1.33	1.34	1.36
		CDM						0.01	0.01	0.02	0.03	0.04	0.05	0.06	0.06	0.07	0.08
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	1.19	1.30	1.21	1.17	1.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West of Thunder Bay	*Burleigh DS*	Non Coincidental Gross						4.12	4.12	4.18	4.24	4.27	4.30	4.33	4.35	4.39	4.42
		CDM						0.03	0.04	0.08	0.11	0.14	0.16	0.19	0.21	0.23	0.25
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.63	3.80	4.10	4.05	3.70	4.09	4.08	4.10	4.13	4.13	4.14	4.14	4.14	4.16	4.17
North of Dryden	*Cat Lake MTS*	Non Coincidental Gross						0.82	0.83	0.85	0.86	0.88	0.89	0.90	0.91	0.92	0.94
		CDM						0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.79	0.69	0.80	0.72	0.74	0.82	0.82	0.83	0.84	0.85	0.85	0.86	0.87	0.88	0.88
West of Thunder Bay	*Clearwater Bay DS*	Non Coincidental Gross						5.47	5.47	5.54	5.61	5.65	5.68	5.71	5.74	5.78	5.83
		CDM						0.04	0.06	0.10	0.15	0.18	0.22	0.25	0.27	0.30	0.33
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.66	4.94	5.38	5.32	4.50	5.43	5.41	5.43	5.46	5.47	5.47	5.46	5.47	5.49	5.49
West of Thunder Bay	*Crilly DS*	Non Coincidental Gross						2.17	2.21	2.25	2.29	2.33	2.36	2.40	2.43	2.46	2.49
		CDM						0.01	0.02	0.04	0.06	0.08	0.09	0.10	0.12	0.13	0.14
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.02	1.98	2.02	1.99	2.05	2.15	2.19	2.21	2.23	2.25	2.27	2.29	2.32	2.33	2.35

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
North of Dryden	*Crow River DS*	Non Coincidental Gross						2.70	2.70	2.74	2.79	2.81	2.84	2.86	2.88	2.90	2.93
		CDM						0.02	0.03	0.05	0.07	0.09	0.11	0.12	0.14	0.15	0.17
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.89	2.52	2.64	2.58	2.12	2.68	2.68	2.69	2.72	2.72	2.73	2.73	2.74	2.75	2.76
West of Thunder Bay	*Dryden TS*	Non Coincidental Gross						21.14	21.33	21.80	22.31	22.65	22.99	23.31	23.63	24.02	24.41
		CDM						0.14	0.23	0.41	0.60	0.74	0.88	1.01	1.12	1.23	1.39
		DG						0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
		Non Coincidental Net	18.66	19.07	20.21	19.94	19.61	20.59	20.69	20.99	21.31	21.51	21.71	21.89	22.10	22.38	22.62
North of Dryden	*Ear Falls DS*	Non Coincidental Gross						4.29	4.32	4.34	4.37	4.39	4.42	4.44	4.46	4.49	4.51
		CDM						0.03	0.05	0.08	0.12	0.14	0.17	0.19	0.21	0.23	0.26
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.43	2.46	2.74	4.23	4.55	4.26	4.27	4.26	4.25	4.25	4.25	4.25	4.25	4.26	4.25
West of Thunder Bay	*Eton DS*	Non Coincidental Gross						5.04	5.04	5.10	5.17	5.21	5.24	5.27	5.30	5.34	5.38
		CDM						0.03	0.05	0.10	0.14	0.17	0.20	0.23	0.25	0.27	0.31
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	4.06	4.16	4.00	3.97	3.74	5.00	4.98	5.00	5.03	5.03	5.03	5.04	5.04	5.06	5.07
Greenstone-Marathon	*Jellicoe DS #3*	Non Coincidental Gross						0.47	0.47	0.48	0.49	0.49	0.50	0.50	0.50	0.51	0.51
		CDM						0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.48	0.47	0.46	0.45	0.33	0.47	0.47	0.47	0.48	0.48	0.48	0.48	0.48	0.48	0.48
West of Thunder Bay	*Kenora DS*	Non Coincidental Gross						6.88	6.88	6.97	7.10	7.17	7.24	7.30	7.37	7.44	7.51
		CDM						0.05	0.07	0.13	0.19	0.23	0.28	0.32	0.35	0.38	0.43
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	11.44	12.50	6.73	6.67	5.93	6.83	6.80	6.84	6.90	6.93	6.96	6.98	7.02	7.06	7.08
West of Thunder Bay	*Keewatin DS*	Non Coincidental Gross						5.55	5.55	5.62	5.73	5.79	5.84	5.89	5.95	6.00	6.06
		CDM						0.04	0.06	0.11	0.15	0.19	0.22	0.26	0.28	0.31	0.35
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net		5.29	5.43	5.41	4.62	5.51	5.49	5.52	5.57	5.60	5.62	5.64	5.66	5.70	5.72
Greenstone-Marathon	*Longlac TS*	Non Coincidental Gross						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	9.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Greenstone-Marathon	*Longlac TS*	Non Coincidental Gross						12.79	13.00	18.00	18.19	18.38	18.57	18.76	18.96	19.15	19.35
		CDM						0.08	0.14	0.34	0.49	0.60	0.71	0.81	0.90	0.98	1.10
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	9.80	10.78	12.66	12.60	11.94	12.70	12.86	17.66	17.70	17.78	17.86	17.95	18.06	18.17	18.25

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Greenstone-Marathon	*Manitouwadge DS #1*	Non Coincidental Gross						1.56	1.56	1.59	1.61	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.01	0.02	0.03	0.04	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.86	1.36	1.54	1.34	1.29	1.55	1.55	1.56	1.56	0.00	0.00	0.00	0.00	0.00	0.00
Greenstone-Marathon	*Manitouwadge TS*	Non Coincidental Gross						11.07	11.10	11.28	11.48	13.21	13.33	13.44	13.55	13.69	13.83
		CDM						0.07	0.12	0.21	0.31	0.43	0.51	0.58	0.64	0.70	0.79
		DG						7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84
		Non Coincidental Net	9.48	10.37	10.79	9.66	9.05	3.15	3.14	3.23	3.33	4.94	4.98	5.02	5.06	5.15	5.20
Greenstone-Marathon	*Marathon DS*	Non Coincidental Gross						11.16	11.21	11.42	11.64	11.78	11.91	12.03	12.16	12.31	12.47
		CDM						0.07	0.12	0.21	0.31	0.38	0.45	0.52	0.58	0.63	0.71
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	7.22	8.08	10.71	10.57	7.56	11.08	11.09	11.20	11.33	11.39	11.45	11.51	11.58	11.68	11.76
West of Thunder Bay	*Margach DS*	Non Coincidental Gross						9.60	9.60	9.73	9.88	9.95	10.01	10.07	10.12	10.21	10.29
		CDM						0.06	0.10	0.18	0.27	0.32	0.38	0.44	0.48	0.52	0.59
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	8.77	9.38	9.44	9.37	8.82	9.53	9.50	9.55	9.61	9.62	9.63	9.63	9.64	9.68	9.70
West of Thunder Bay	*Minaki DS*	Non Coincidental Gross						0.99	0.99	1.00	1.02	1.02	1.03	1.03	1.04	1.05	1.06
		CDM						0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.94	1.06	0.97	0.93	1.00	0.98	0.98	0.98	0.99	0.99	0.99	0.99	0.99	0.99	1.00
Thunder Bay	*Murillo DS*	Non Coincidental Gross						19.37	19.61	19.88	19.95	20.27	20.64	20.84	21.03	21.21	21.39
		CDM						0.13	0.21	0.37	0.54	0.66	0.79	0.90	1.00	1.09	1.22
		DG						0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.12	0.12
		Non Coincidental Net	12.12	12.93	12.43	11.34	15.35	19.22	19.37	19.48	19.39	19.59	19.83	19.91	20.01	20.00	20.05
West of Thunder Bay	*Nestor Falls DS*	Non Coincidental Gross						3.36	3.36	3.41	3.46	3.48	3.50	3.52	3.54	3.56	3.59
		CDM						0.02	0.04	0.06	0.09	0.11	0.13	0.15	0.17	0.18	0.20
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.22	3.32	3.33	3.29	3.05	3.34	3.33	3.34	3.36	3.36	3.37	3.36	3.37	3.38	3.39
Thunder Bay	*Nipigon DS*	Non Coincidental Gross						2.21	2.24	2.27	2.29	2.33	2.38	2.41	2.44	2.47	2.50
		CDM						0.01	0.02	0.04	0.06	0.08	0.09	0.10	0.12	0.13	0.14
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.32	2.19	2.31	2.23	2.17	2.19	2.21	2.23	2.23	2.26	2.29	2.31	2.32	2.34	2.36
North of Dryden	*Perrault Falls DS*	Non Coincidental Gross						0.79	0.80	0.81	0.83	0.83	0.84	0.85	0.86	0.87	0.88
		CDM						0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.89	0.91	0.78	0.86	0.86	0.79	0.79	0.79	0.80	0.81	0.81	0.81	0.82	0.82	0.83

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Greenstone-Marathon	*Pic DS*	Non Coincidental Gross						6.57	6.58	6.67	6.78	6.84	6.89	6.94	6.98	7.05	7.11
		CDM						0.04	0.07	0.12	0.18	0.22	0.26	0.30	0.33	0.36	0.41
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.96	6.94	6.37	6.50	6.38	6.52	6.50	6.55	6.60	6.61	6.62	6.63	6.65	6.68	6.71
North of Dryden	*Red Lake TS*	Non Coincidental Gross						26.58	26.81	27.04	27.27	27.41	27.64	27.88	28.12	28.36	28.61
		CDM						0.18	0.29	0.51	0.73	0.89	1.05	1.21	1.34	1.46	1.63
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	45.06	47.55	48.55	49.17	50.28	26.40	26.52	26.53	26.54	26.51	26.59	26.67	26.78	26.91	26.98
Thunder Bay	*Red Rock DS*	Non Coincidental Gross						4.01	4.02	4.04	4.02	4.06	4.09	4.10	4.10	4.11	4.11
		CDM						0.03	0.04	0.08	0.11	0.13	0.16	0.18	0.20	0.21	0.23
		DG						0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.23	0.23
		Non Coincidental Net	3.97	3.87	4.08	4.09	4.02	3.95	3.94	3.93	3.88	3.88	3.90	3.88	3.87	3.67	3.64
West of Thunder Bay	*Sam Lake DS*	Non Coincidental Gross						23.97	24.05	24.44	24.88	25.12	25.36	25.57	25.79	26.07	26.36
		CDM						0.16	0.26	0.46	0.67	0.82	0.97	1.11	1.23	1.34	1.50
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	19.80	22.25	23.23	23.00	23.42	23.80	23.78	23.98	24.20	24.30	24.38	24.46	24.56	24.73	24.85
West of Thunder Bay	*Sapawe DS*	Non Coincidental Gross						0.95	0.95	0.97	0.98	0.99	1.00	1.01	1.01	1.02	1.03
		CDM						0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.95	0.80	0.94	0.92	2.61	0.95	0.94	0.95	0.96	0.96	0.96	0.96	0.97	0.97	0.97
Greenstone-Marathon	*Schreiber Winnipg DS*	Non Coincidental Gross						5.19	5.20	5.29	5.38	5.43	5.48	5.52	5.57	5.63	5.69
		CDM						0.03	0.06	0.10	0.14	0.18	0.21	0.24	0.26	0.29	0.32
		DG						0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	4.47	5.21	5.19	5.07	5.32	5.15	5.15	5.19	5.22	5.24	5.26	5.27	5.29	5.33	5.35
West of Thunder Bay	*Shabaqua DS*	Non Coincidental Gross						2.80	2.81	2.85	2.89	2.92	2.94	2.96	2.98	3.01	3.04
		CDM						0.02	0.03	0.05	0.08	0.10	0.11	0.13	0.14	0.15	0.17
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.64	2.83	2.83	2.81	2.74	2.78	2.77	2.79	2.81	2.82	2.83	2.83	2.84	2.85	2.86
West of Thunder Bay	*Sioux Narrows DS*	Non Coincidental Gross						4.49	4.49	4.55	4.62	4.65	4.68	4.71	4.73	4.77	4.81
		CDM						0.03	0.05	0.09	0.12	0.15	0.18	0.20	0.23	0.25	0.27
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.09	4.25	4.37	4.34	4.22	4.46	4.44	4.46	4.49	4.50	4.50	4.50	4.51	4.53	4.54
North of Dryden	*Slate Falls DS*	Non Coincidental Gross						0.64	0.64	0.65	0.66	0.67	0.67	0.68	0.68	0.69	0.70
		CDM						0.00	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.04	0.04
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.56	0.63	0.62	0.61	0.61	0.64	0.63	0.64	0.64	0.65	0.65	0.65	0.65	0.65	0.66

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
West of Thunder Bay	*Valora DS*	Non Coincidental Gross						0.77	0.78	0.79	0.81	0.83	0.84	0.85	0.86	0.88	0.89
		CDM						0.01	0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.04	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.64	0.70	0.74	0.73	0.69	0.77	0.77	0.78	0.79	0.80	0.81	0.81	0.82	0.83	0.84
West of Thunder Bay	*Vermilion Bay DS*	Non Coincidental Gross						3.95	3.97	4.01	4.06	4.09	4.12	4.15	4.18	4.21	4.25
		CDM						0.03	0.04	0.08	0.11	0.13	0.16	0.18	0.20	0.22	0.24
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.22	2.36	2.37	2.43	2.10	3.93	3.92	3.94	3.95	3.96	3.96	3.97	3.98	3.99	4.00
West of Thunder Bay	*Whitedog DS*	Non Coincidental Gross						2.37	2.39	2.41	2.44	2.46	2.49	2.51	2.54	2.56	2.59
		CDM						0.02	0.03	0.05	0.07	0.08	0.09	0.11	0.12	0.13	0.15
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	1.97	2.19	2.30	2.40	2.31	2.35	2.36	2.37	2.37	2.38	2.39	2.40	2.42	2.43	2.44
Greenstone-Marathon	*White River DS*	Non Coincidental Gross						7.02	7.06	7.18	7.32	7.41	7.49	7.56	7.64	7.73	7.83
		CDM						0.05	0.08	0.13	0.20	0.24	0.29	0.33	0.36	0.40	0.45
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.20	3.20	6.80	6.74	6.44	6.98	6.98	7.05	7.13	7.16	7.20	7.23	7.28	7.34	7.38

Appendix E. Past Sustainment Activities in Northwest Ontario

Station	I/S Date	Asset Class
ALEXANDER SS	8-Dec-16	Breaker: SF6_115 kV
BIRCH TS	3-Dec-15	Transformer: Step-down_115 kV
DRYDEN TS	29-Aug-16	Breaker: SF6_115 kV
	14-Jul-16	Breaker: SF6_115 kV
	20-Oct-16	Breaker: SF6_115 kV
	10-Nov-16	Breaker: SF6_115 kV
	29-May-16	Breaker: SF6_115 kV
	23-Jul-14	Breaker: SF6_13.8 kV
	4-Sep-14	Breaker: SF6_13.8 kV
	29-Aug-16	Switch: Air Break_115 kV
	29-Aug-16	Switch: Air Break_115 kV
	14-Jul-16	Switch: Air Break_115 kV
	14-Jul-16	Switch: Air Break_115 kV
	31-Aug-16	Switch: Air Break_115 kV
	20-Oct-16	Switch: Air Break_115 kV
	10-Nov-16	Switch: Air Break_115 kV
	20-Oct-16	Switch: Air Break_115 kV
	29-May-16	Switch: Air Break_115 kV
	1-Nov-16	Switch: Air Break_115 kV
	23-Jul-14	Switch: Air Break_13.8 kV
	4-Sep-14	Switch: Air Break_ 13.8 kV
FORT FRANCES TS	23-Nov-10	Breaker: SF6_13.8 kV
	2-Sep-10	Breaker: SF6_13.8 kV
	2-Oct-13	Switch: Air Break_115 kV
	27-Nov-15	Switch: Air Break_230 kV
	2-Oct-13	Switch: Ground_115 kV
	27-Nov-15	Switch: Ground_230 kV
	2-Sep-10	Switch: Air Break_ 13.8 kV
	2-Oct-16	Switch: Air Break_115 kV
	12-Sep-14	Switch: Ground_ 44 kV
	23-Nov-10	Switch: Air Break_ 13.8 kV
LAKEHEAD TS	27-Sep-11	Breaker: SF6_115 kV
	14-Dec-11	Breaker: SF6_115 kV
	14-Dec-11	Breaker: SF6_115 kV
	1-Dec-09	Breaker: SF6_13.8 kV
	4-Apr-12	Switch: Ground_ 13.8 kV
	16-Nov-09	Switch: Ground_ 13.8 kV
	16-Nov-09	Switch: Air Break_ 13.8 kV
	21-Oct-09	Switch: Ground_ 13.8 kV
	21-Oct-09	Switch: Air Break_ 13.8 kV
	12-Sep-16	Transformer: Autotransformer_230 kV

Station	I/S Date	Asset Class
KENORA TS	15-Jul-2009	Breaker: SF6_13.8 kV
	29-May-2015	Switch: Air Break_230 kV
	29-May-2015	Switch: Ground_230 kV
	26-Feb-2013	Switch: Air Break_230 kV
	15-Jul-2009	Switch: Air Break_ 13.8 kV
MACKENZIE TS	17-Jun-2010	Breaker: SF6_13.8 kV
MANITOUWADGE TS	2-Jul-2016	Breaker: SF6_27.6 kV
	10-Jul-2016	Switch: Air Break_ 44 kV
	9-Jul-2016	Transformer: Step-down_115 kV
MARATHON TS	25-May-2009	Breaker: SF6_230 kV
	26-Mar-2014	Breaker: SF6_13.8 kV
	18-Dec-2013	Breaker: SF6_13.8 kV
	23-Dec-2016	Switch: Air Break_230 kV
	23-Dec-2016	Switch: Ground_230 kV
	26-Mar-2014	Switch: Air Break_ 13.8 kV
	18-Dec-2013	Switch: Air Break_ 13.8 kV
MOOSELAKE TS	8-Sep-2014	Breaker: SF6_115 kV
	31-Jul-2014	Breaker: SF6_115 kV
	29-May-2014	Breaker: SF6_115 kV
	8-Sep-2014	Breaker: SF6_115 kV
	11-Jul-2014	Breaker: SF6_115 kV
PORT ARTHUR TS #1	11-Aug-2015	Switch: Air Break_115 kV
	25-Nov-2009	Switch: Air Break_115 kV
	11-Nov-2009	Switch: Air Break_115 kV
	21-Sep-2012	Switch: Air Break_115 kV
	20-Nov-2009	Switch: Air Break_115 kV
	6-Nov-2009	Switch: Air Break_115 kV
	22-Jun-2015	Switch: Air Break_115 kV
	2-Jun-2015	Switch: Air Break_115 kV
	21-Sep-2012	Switch: Air Break_115 kV
	21-Sep-2012	Switch: Ground_115 kV
RABBIT LAKE SS	16-Dec-2011	Breaker: SF6_115 kV
	10-Nov-2011	Breaker: SF6_115 kV
	22-Oct-2011	Switch: Air Break_115 kV
	25-Nov-2016	Switch: Air Break_115 kV
	15-Nov-2016	Switch: Ground_115 kV
	23-Oct-2011	Switch: Air Break_115 kV

Appendix F. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Windsor-Essex

REGIONAL INFRASTRUCTURE PLAN

December 22, 2015

hydro one

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Prepared and endorsed by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
E.L.K. Energy Inc.
Entegrus Powerlines Inc.
EnWin Utilities Ltd.
Essex Powerlines Corporation
Hydro One Networks Inc. (Distribution)

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and also any additional near and mid-term needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE WINDSOR-ESSEX REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator
- E.L.K. Energy Inc.
- Entegrus Powerlines Inc.
- EnWin Utilities Ltd.
- Essex Powerlines Corporation
- Hydro One Networks Inc. (Distribution)

This RIP provides a consolidated summary of needs and recommended plans for Windsor-Essex Region. No long-term needs (10 to 20 years) and associated plans have been identified.

This RIP is the final phase of the regional planning process and it follows the completion of the Windsor-Essex Region Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 [1].

The major infrastructure investments planned, or being planned, for the Windsor-Essex Region over the near and medium-term identified in the various phases of the regional planning process are given in the table below.

No.	Project	I/S Date	Cost
1*	Supply to Essex County Transmission Reinforcement (SECTR TX) Project	June 2018	$77.4M
2*	Supply to Essex County Transmission Reinforcement (SECTR DX) Project	June 2018	$19.3M
3	Replacement of Keith end-of-life autotransformers	2020	$45M
4	Replacement of Kingsville end-of-life transformers	2018	$12M
5	230kV/115kV circuit and 27.6kV feeder reconfiguration at Keith TS due to Gordie Howe International Bridge (GHIB) Project	2018	$63M
6	Additional feeder position at Malden TS	TBD	TBD
7	Decommission of Tilbury TS	2019	TBD
8	Decommission of T1 Transformer at Keith TS	TBD	TBD

* These projects address the needs identified in the Windsor-Essex IRRP study for the region in the near and medium-term.

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. Should there be any new needs that emerge due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE WINDSOR-ESSEX REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") and documents the results of the joint study carried out by Hydro One, EnWin Utilities Ltd. ("EnWin"), Essex Powerlines Corporation, E.L.K. Energy Inc. ("E.L.K Energy"), Entegrus Inc. ("Entegrus"), Hydro One Networks Inc. (Distribution) ("Hydro One Distribution), and the Independent Electricity System Operator ("IESO") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013.

The Windsor-Essex Region comprises the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. The map of the region is shown in Figure 1-1 below.

The Windsor-Essex area is supplied from a combination of generation located in the region and from the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations. The region peak electricity demand of about 800 MW is provided from three 230 kV and fourteen 115 kV step-down transformer stations.

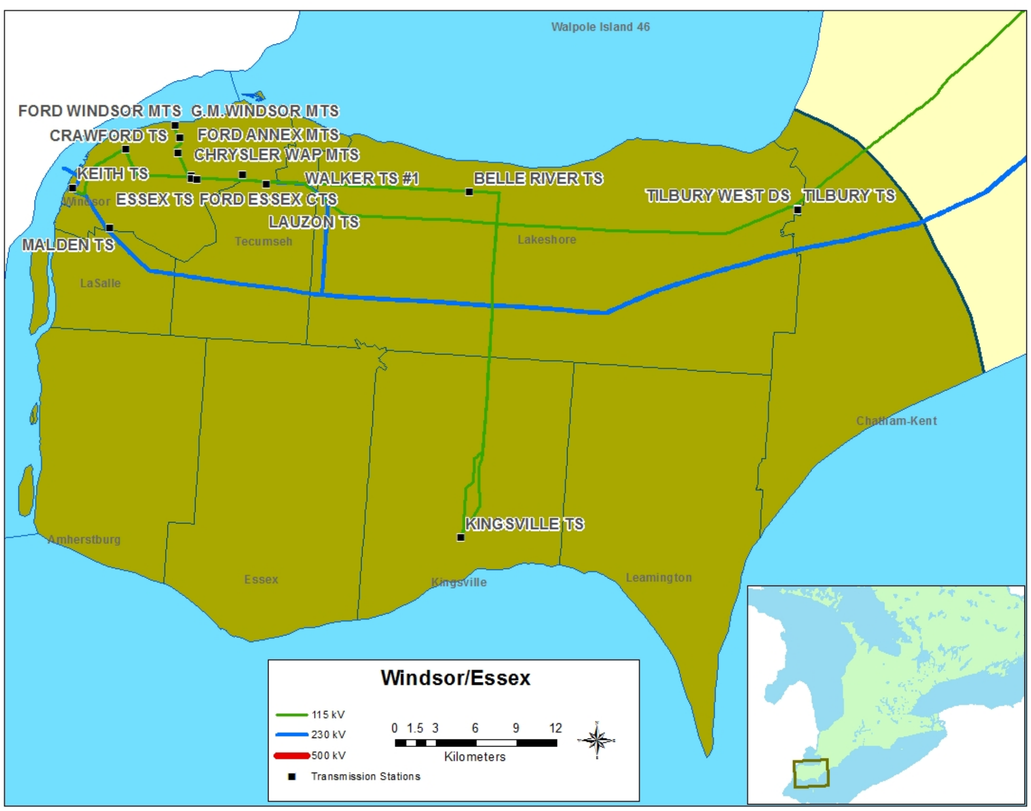


Figure 1-1 Geographical Map of Windsor-Essex Region

1.1 Scope and Objectives

This RIP report examines the needs in the Windsor-Essex Region. Its objectives are to: identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), Local Plan ("LP"), and/or Integrated Regional Resource Plan ("IRRP")); assess and develop wires plans to address these needs; provide the status of wires planning currently underway or completed for specific needs; and identify investments in transmission and distribution facilities or both that should be developed and implemented to meet the electricity infrastructure needs within the region.

Planning activities for the Windsor-Essex Region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete and the Windsor-Essex Region was identified as a "transitional" region. The planning status for the region was considered to be in the IRRP phase of the regional planning process. An IRRP for the region was completed in April 2015.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (NA, SA, LP, and/or IRRP).
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information.
- Develop a plan to address any longer term needs identified by the Working Group.

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the region.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the regional needs.
- Section 7 provides a summary of regional plans.
- Section 8 provides summary of other projects.
- Section 9 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a

[1] Also referred to as Needs Screening

need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region. Since the Windsor-Essex Region was in transition to the new regional planning process, the IESO led IRRP engagement for this region was initiated after the completion of the IRRP.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

The regional planning process specifies a 20 year planning assessment period for the IRRP. The RIP focuses on the wires options and, given the forecast uncertainty and the fact that adequate time is available to identify and plan new wire facilities in subsequent planning cycles, a study period of 10 years is considered adequate for the RIP. The exception would be the case where major transmission infrastructure investments are required. In these cases the RIP would review and assess longer term needs and develop a longer term plan.

To efficiently manage the regional planning process in the region, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- Participating in and conducting wires planning as part of the IRRP for the region.
- Working and planning connection capacity requirements with the LDCs.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

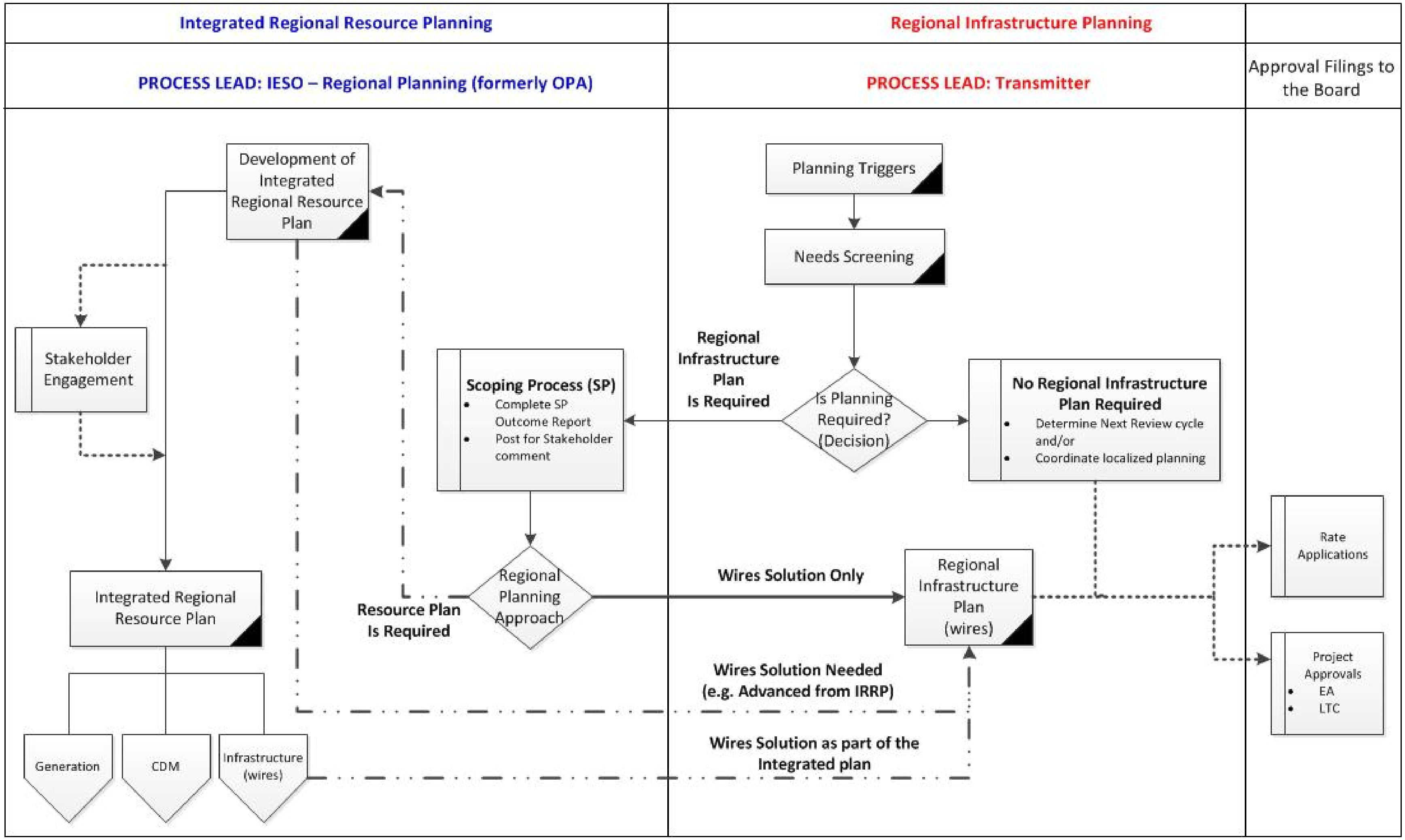


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP process is a four step process as shown in Figure 2-2 below.

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

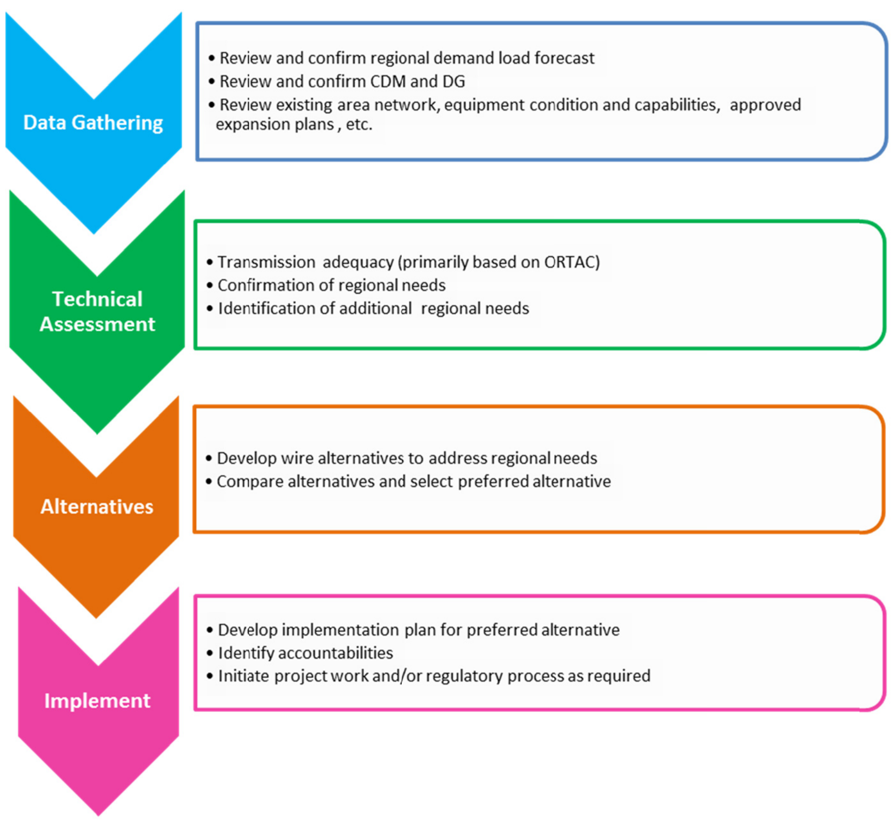


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE WINDSOR-ESSEX REGION COMPRISES THE CITY OF WINDSOR, TOWN OF AMHERSTBURG, TOWN OF ESSEX, TOWN OF KINGSVILLE, TOWN OF LAKESHORE, TOWN OF LASALLE, MUNICIPALITY OF LEAMINGTON, TOWN OF TECUMSEH, THE WESTERN PORTION OF THE MUNICIPALITY OF CHATHAM-KENT AND THE TOWNSHIP OF PELEE ISLAND.

The region is served by five LDCs: EnWin, Essex Powerlines Corporation, E.L.K. Energy, Entegrus, and Hydro One Distribution, whose service territories are shown in Figure 3-1. EnWin and Hydro One Distribution are directly connected to the transmission system, while the three other LDCs have low voltage connections.

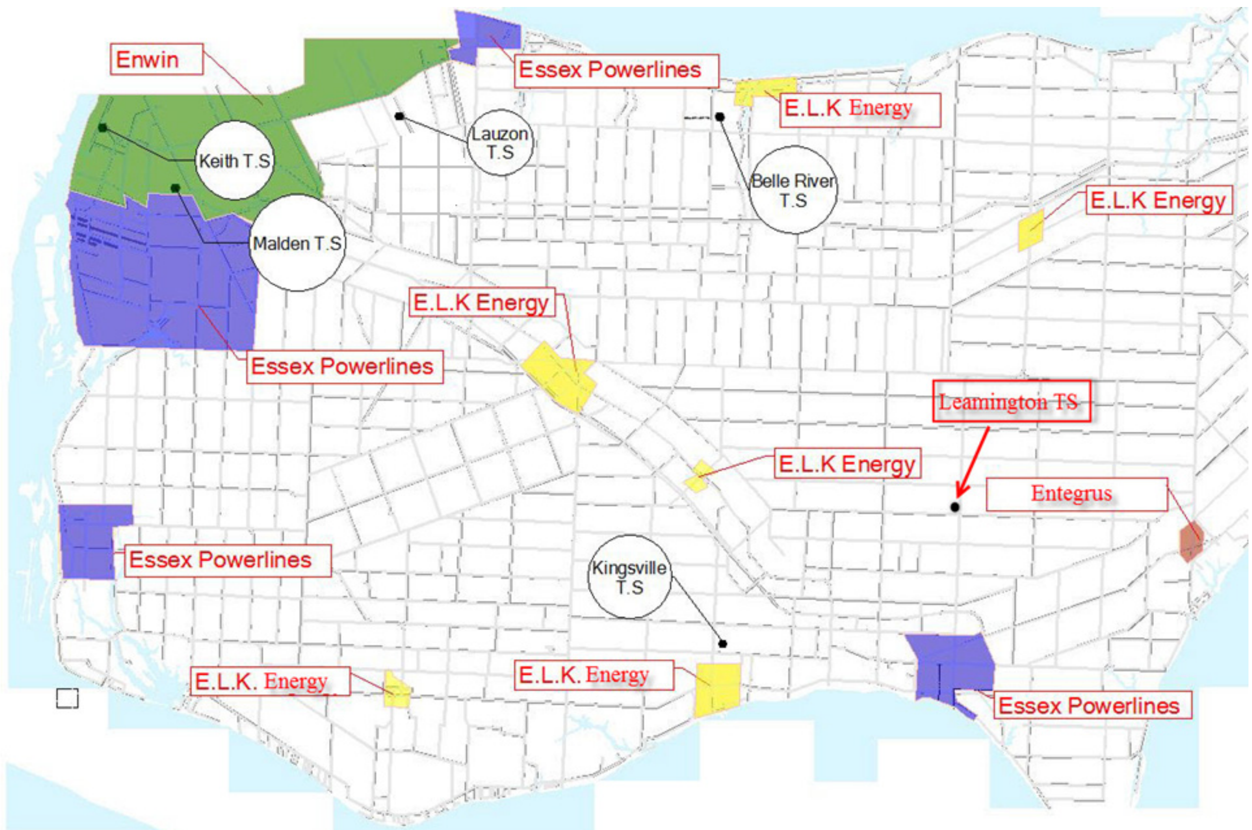


Figure 3-1 LDC Service Territories

The region peak electricity demand of about 800 MW is supplied from a combination of local generation and from connection to the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations shown in Figure 3-2 below.

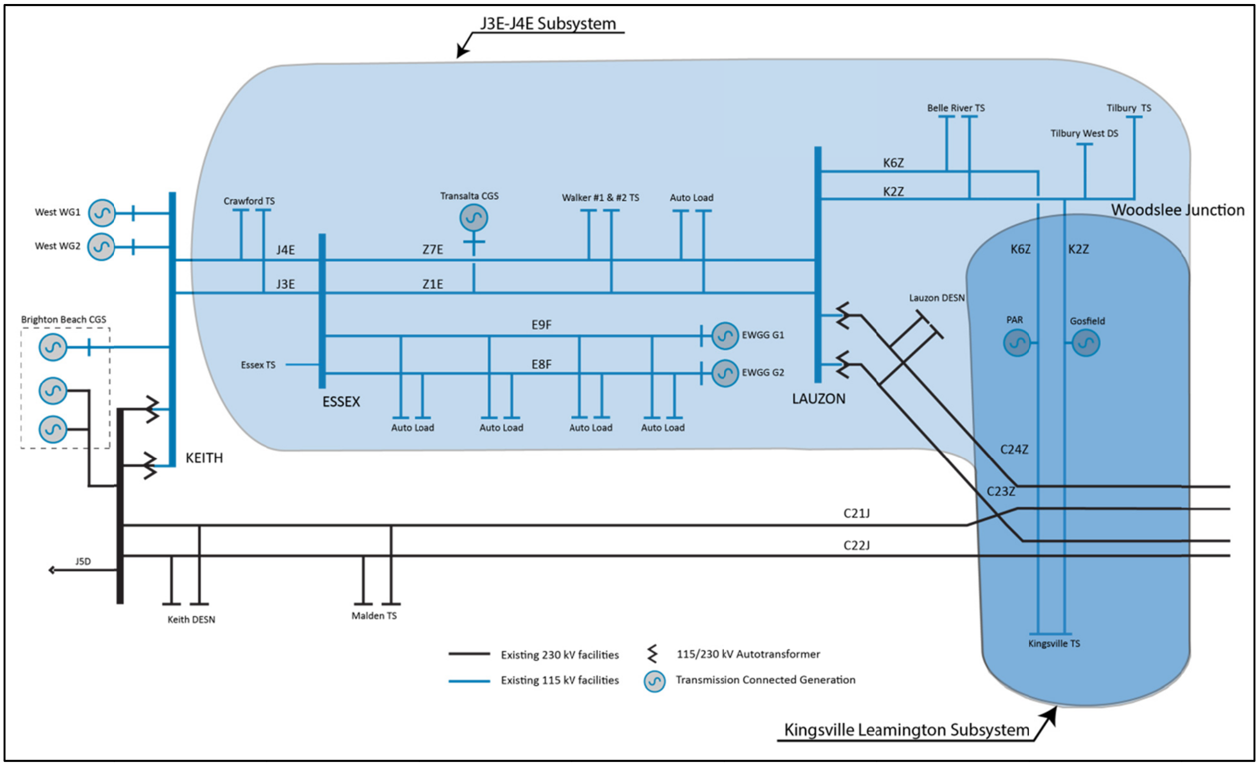


Figure 3-2 Windsor-Essex Area Subsystems/Single Line Diagram

The main transmission corridor in the region connects with the rest of the Hydro One system at Chatham Switching Station ("SS") and connects the Ontario transmission system with the Michigan transmission system at Keith TS.

The region's 115 kV network connects to the 230 kV transmission system at Keith TS and Lauzon TS via two auto-transformers in each station. About 65% of the area load is supplied by fourteen step-down transformers stations connected to the 115 kV network, while the balance is supplied by three step-down transformer stations connected to the 230 kV network. Table 3-1 lists the region's step-down transformer stations.

There are six customer-owned generating plants in the region connecting at the 230 kV and 115 kV levels with a combined contract capacity of 927 MW. In addition, the distributed generation connected at various locations to low-voltage ("LV") feeders in the region account for about 65 MW of effective capacity. Table 3-1 list the region's transmission connected generations.

The transmission system in the region can be divided into two "nested" sub-systems:

- The Kingsville-Leamington subsystem: customers supplied from Kingsville TS and
- The J3E-J4E subsystem: customers supplied from stations connected to the Windsor-Essex 115 kV system, as well as customers supplied from the 230/27.6 kV Lauzon DESN.

As can be noted in Figure 3-2 below, the Kingsville-Leamington subsystem is nested within the J3E-J4E subsystem. Therefore, increasing supply to the Kingsville-Leamington subsystem or transferring load from the existing Kingsville TS to a new 230 kV TS will impact the supply and demand balance in the J3E-J4E subsystem.

Table 3-1 Stations Included in the Windsor-Essex Region

Station (DESN)	Voltage Level (kV)	Supply Circuits	Connected Customer(s)
Belle River TS (T1/T2)	115/27.6	K2Z/K6Z	Hydro One Distribution
Kingsville TS (T1/T2/T3/T4)	115/27.6	K2Z/K6Z	E.L.K. Energy Essex Powerlines Corp. Hydro One Networks Inc.
Lauzon TS (T5/T6/T7/T8)	230/27.6	C23Z/C24Z	EnWin Utilities Ltd. Hydro One Distribution
Tilbury West DS	115/27.6	K2Z	Hydro One Distribution
Tilbury TS (T1)	115/27.6	K2Z	Hydro One Distribution
Chrysler WAP MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Crawford TS (T3/T4)	115/27.6	J3E/J4E	EnWin Utilities Ltd.
Essex TS (T5/T6)	115/27.6	Z7E/	EnWin Utilities Ltd.
Ford Annex MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Ford Essex CTS	115/13.8	Z1E/Z7E	EnWin Utilities Ltd.
Ford Windsor MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
G.M. Windsor MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Keith TS (T1)	115/27.6	C21J/C22J	Brighton Beach Power LP West Windsor Power EnWin Utilities Ltd. Essex Powerlines Corp. Hydro One Distribution
Keith TS (T22/T23)	230/27.6	C21J/C22J	
Malden TS (T1/T2)	230/ 27.6	C21J/C22J	EnWin Utilities Ltd. Essex Powerlines Corp. Hydro One Distribution
Walker MTS #2	115/27.6	Z1E/Z7E	EnWin Utilities Ltd.
Walker TS #1 (T3/T4)	115/27.6	Z1E/Z7E	EnWin Utilities Ltd.

Table 3-2 Transmission Connected Generation Facilities in the Region

Technology	Station Name	Contract Expiry Date	Connection Point	Contract Capacity (MW)	Summer Effective Capacity (MW)
Combined Cycle Generating Facility	Brighton Beach Power Station	Dec. 31, 2024	Keith TS	541	526
Combined Heat and Power (CHP)	West Windsor Power	May 31, 2031	J2N (Keith TS)	128	107
	TransAlta Windsor	Dec. 1, 2031	Z1E	74	74
	East Windsor Cogeneration Centre	Nov. 5, 2029	E8F/E9F	84	80
Renewables	Gosfield Wind Project	Jan. 12, 2029	K2Z	51	8
	Point Aux Roches Wind Farm	Dec. 5, 2031	K6Z	49	8

4. TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED OR ARE UNDERWAY BY HYDRO ONE, AIMED AT IMPROVING THE SUPPLY TO THE WINDSOR-ESSEX REGION. A BRIEF LISTING OF THE COMPLETED PROJECTS OVER THE LAST 10 YEARS IS GIVEN BELOW:

- Belle River TS (May 2006): Built a new 2-25/33/42 MVA 115/27.6 kV transformer station in the Town of Lakeshore supplied from 115 kV circuits K2Z/K6Z. The station provides additional load supply capability to meet the load requirements of Hydro One Distribution customers in the Town of Lakeshore. The connection of new station required the untwining of K6Z to obtain two circuits (K2Z and K6Z) with K6Z on the north side of the towers. The new K2Z circuit section which only extends to Belle River TS was then connected to the then existing K2Z circuit just outside of Lauzon TS.

- Essex TS (October 2008): The station was refurbished with new 2-50/66/83 MVA 115/27.6 kV transformers. The 115 kV supply circuits were reconfigured to mitigate exposure to customer load loss for loss of a single transmission element under certain system conditions.

- Malden TS: Transformer T2 75/100/125 230/27.6 kV was replaced (July 2010) and T1 was replaced (December 2011).

- Keith TS: T23 transformer 50/67/83 MVA 230/27.6 kV was replaced (October 2008) and T22 transformer 50/67/83 MVA 230/27.6 kV was replaced (December 2013).

- Walker TS #1: Reactor installation for short circuit mitigation (June 2011).

- Kingsville TS: Reactor installation for short circuit mitigation (November 2011).

- Keith TS: Reactor installation for short circuit mitigation (April 2012).

- Lauzon TS: Three breakers were replaced: SC2Q (June 2012), SC3E (April 2012) and SC4J (April 2012).

- Keith TS: Six breakers were replaced: SC11K (May 2014), SC11SC (May 2014), SC1B (June 2014), T11P (August 2014), T12P (October 2014), SC2Y (January 2015).

The following projects are currently underway:

- Crawford TS: is a 115/28 kV, with two 50/67/83 MVA units in Windsor. It supplies the downtown Windsor area with a current peak load of 60 MW. The existing T3 transformer is at the end-of-life with leaky fittings and headboard. The T3 fire suppression system and separation wall also needs to be upgraded to current standards. The current plan is to replace T3 transformer and install neutral grounding reactors on the T3 and T4 transformer units. The project includes protection and control upgrades and relocation of battery, necessary spill containment facilities at Crawford TS. The project is under execution for $8.46 million with an in-service date of December 15, 2016. There are no cost implications for the LDCs. Once this project is complete the station will meet the current design standards.

5. LOAD FORECAST AND OTHER ASSUMPTIONS

THE FORECASTS REFLECT THE EXPECTED PEAK DEMAND AT EACH STATION UNDER EXTREME WEATHER CONDITIONS, BASED ON FACTORS SUCH AS POPULATION, HOUSEHOLD AND ECONOMIC GROWTH, CONSISTENT WITH MUNICIPAL PLANNING ASSUMPTIONS.

5.1 Historical Demand

The peak demand in the Windsor-Essex Region has declined from a high of 1060 MW in the summer of 2006 to approximately 800 MW in both 2013 and 2014.

Figure 5-1 shows the historical summer peak demand observed in the region from 2004 to 2014. A noticeable peak in 2006 is coincident with the all-time peak in Ontario power demand, while a dip in 2008 and 2009 shows the area's response to the global recession. There is a large concentration of automotive manufacturing facilities in the City of Windsor. The sector is a major economic driver and electricity user within the region. The decline in Ontario's manufacturing sector and the 2008/09 economic downturn have both contributed to a decline in electricity use in the region.

While the manufacturing sector continues to face challenges in recovering, economic diversification is changing the region's growth and electricity use. The five-year Windsor-Essex Regional Economic Roadmap, released in 2011, identifies nine industry groups that hold growth potential for the region, including advanced manufacturing, tourism, and agri-business.

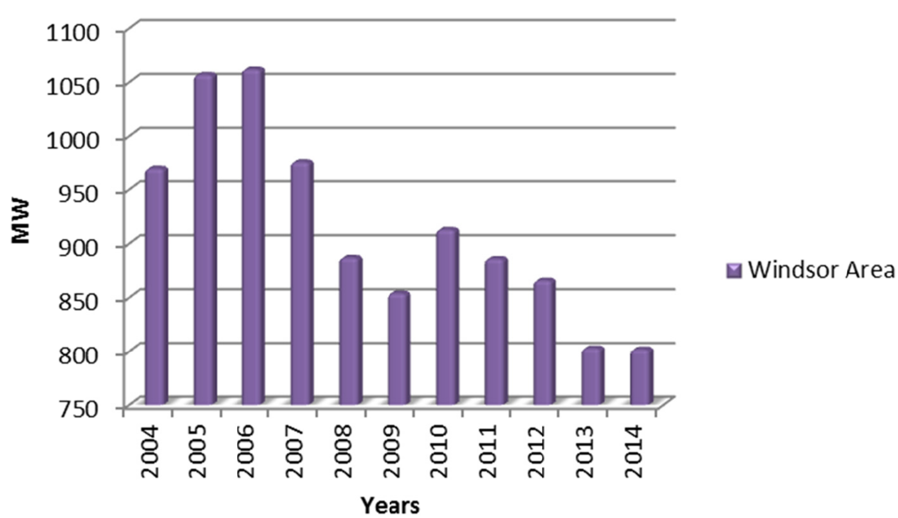


Figure 5-1 Historical Load Demand in Windsor-Essex Region

The peak demand in the Kingsville-Leamington area has also experienced fluctuations over the 2004-2014 period as shown in Figure 6-1.

5.2 Contribution of CDM and DG

In developing the planning forecast, the following process was used to assess the Windsor-Essex Region:

a) First, "gross demand" is established. Gross demand reflects the forecast developed and provided by the area LDCs and is influenced by a number of factors such as economic, household and population growth.
b) Second, "net demand" is derived by reducing the gross demand by expected savings from improved building codes and equipment standards, customer response to time-of-use pricing, and projected province-wide CDM programs. This information is provided by the IESO.
c) Lastly, a "planning forecast" is determined by reducing net demand by the contribution in the area from existing, committed and forecast DG. This information is provided by the IESO.

5.3 Gross and Net Demand Forecast

Summer peak gross non-coincident demand forecasts for the 20-year planning horizon were provided by EnWin and Hydro One Distribution, the two LDCs which are directly connected to the transmission system, for each of the transformer stations in the area. The forecasts from Hydro One Distribution include forecasts provided by the appropriate embedded LDCs.

The development of the load forecast for this RIP report followed a two-stage process:

(a) Using the forecast provided by the LDCs, the year by year growth rate for each station was first developed.
(b) The 2014 summer actual peak load, corrected for extreme weather, for each station was obtained.
(c) The growth rates from (a) were then applied to the 2014 summer peak load of (b) to obtain the gross load forecast for each station for extreme weather conditions.

The gross load forecasts, for extreme weather conditions, by station and by subsystem are shown in Appendix A. This load forecast reflects the following:

- A shift of load, commencing in 2016, from Walker TS #1 and #2 to Essex TS and GM MTS.
- Reduction in Kingsville TS load.
- Increase in loads at Keith TS, Crawford TS and Lauzon TS.

The gross load forecasts, for extreme weather conditions, by station and by subsystem are shown in Appendix A. Figure 5-2 is a graph of the Windsor – Essex Region extreme weather peak summer non-coincident load forecast. The overall region will experience an average annual growth rate of just less than 1%, while the Kingsville-Leamington area average growth rate would be about 1.6%.

Figure 5-2 also shows the load forecast from the IRRP report. The two forecasts are not materially different; hence the load forecast in this RIP report will not alter the conclusions of the IRRP.

The Reference Planning forecast (Appendix D) for each station is obtained by reducing the gross load forecast for the station by the amount of forecast conservation and DG. The conservation forecast (Appendix B) and the DG forecast (Appendix C) are the same as used in the IRRP report.

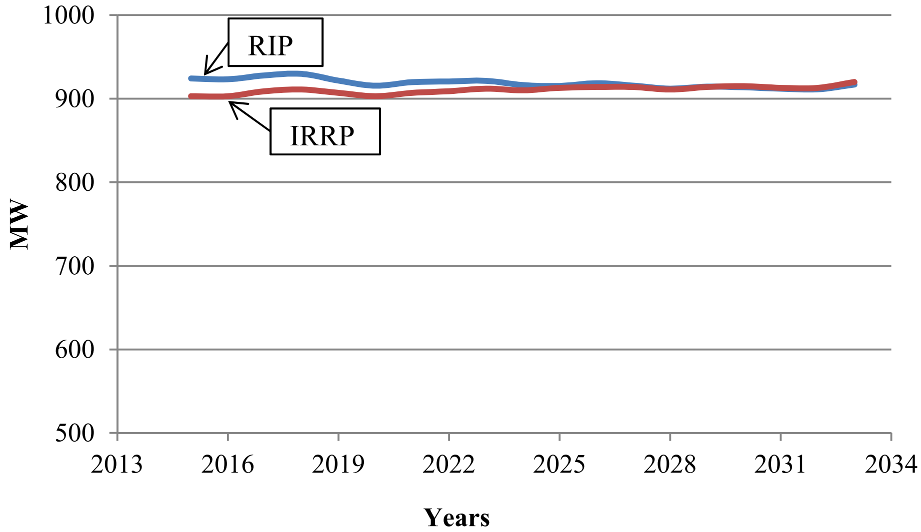


Figure 5-2 Reference Forecast in Windsor-Essex Region

5.4 Other Study Assumptions

The following other assumptions are made in this report.

1) The Study period for the RIP assessment is 2015-2025.
2) All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
3) Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity. Load is assumed at 90% lagging power factor, unless known.
5) Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR), while some LDCs use different methodologies for determining transformer station LTR.

6. REGIONAL NEEDS

THIS SECTION SUMMARIZES THE WINDSOR-ESSEX REGION NEEDS OVER THE NEAR AND MID TERM. NO LONG TERM NEEDS HAVE BEEN IDENTIFIED.

Earlier studies by the IESO, ("Windsor-Essex Region Integrated Regional Resource Plan" - April 28, 2015, Supply to Essex County Transmission Reinforcement Project, January 2014) identified two near-term needs in the region. These needs are:

- **Minimize the Impact of Supply Interruptions in the J3E-J4E Subsystem:**
  The existing system lacks the capability to restore power to customers in the J3E-J4E subsystem in accordance with the ORTAC criteria, i.e., restoration of all loads within 8 hours. Based on current and forecast demand, up to 170 MW 0f the load interrupted cannot be restored by 2017.

- **Additional Supply Capacity in the Kingsville-Leamington Area:**
  Demand in the Kingsville-Leamington subsystem has already exceeded the load meeting capability of 120 MW in recent 3 years and is expected to continue to exceed the supply capacity over the forecast period. Figure 6-1 below shows the historical and forecast demand and supply capabilities in the Kingsville-Leamington subsystem after conservation and DG are taken into consideration.

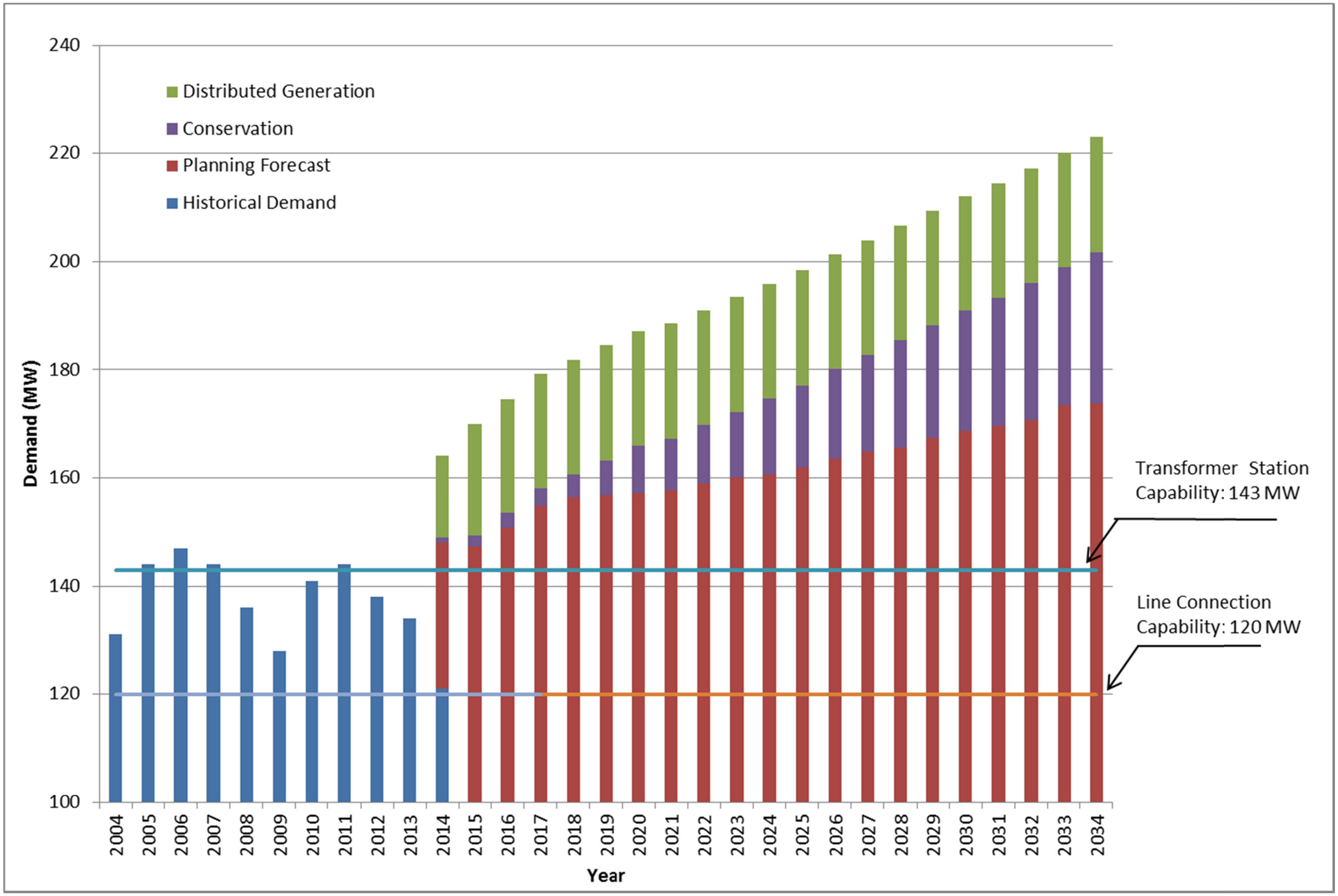


Figure 6-1 Historical and Forecast Demand of Kingsville-Leamington Subsystem

In addition, Hydro One has also identified infrastructure and major equipment which need replacement during the study period. The current plan is essentially a like-for-like replacement of 3 step-down transformers at Kingsville TS and 2 auto-transformers at Keith TS.

These regional needs are summarized in Table 6-1 and include needs for which work is already underway and/or being addressed. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

Table 6-1 Summary of Needs

Type	Needs	Timeline	Process
Capacity to Meet Demand	Kingsville-Leamington Subsystem	2018	**IRRP**
Minimize the Impact of Interruption	J3E-J4E Subsystem	2018	**IRRP**
Aging Equipment Replacement	3 transformers at Kingsville TS are at end-of-life	Near-Term	**RIP**
Aging Equipment Replacement	2 autotransformers at Keith TS are at end-of-life	Near-Term	**RIP**

7. REGIONAL INFRASTRUCTURE PLANS

THIS SECTION PRESENTS WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES SOLUTION FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE WINDSOR-ESSEX REGION.

7.1 Supply to Essex County Transmission Reinforcement (SECTR) Project

7.1.1 Description

The SECTR project as presented in the IRRP is an integrated solution to address both the J3E-J4E subsystem restoration need and the Kingsville – Leamington capacity need. As illustrated in Figure 7-1 the project consists of the installation of a new 230 kV supplied transformer station near Leamington connected to the existing C21J/C22J circuits via a new 13 km double-circuit 230 kV connection line on a new right-of-way.

The total cost of this project is $96.7M made up of:

(a) Build 230/27.6 – 27.6 kV 75/100/125 MVA Leamington TS with six LV breaker positions, plus other required switchgear: $32.1M
(b) Build a 13 km 2-circuit 230 kV line on a new right-of-way tapping into existing 230 kV circuits C21J/C22J plus Optical Ground Wire: $45.3M.
(c) Carry out distribution work for Leamington TS: $19.3M. Other additional distribution work includes two additional feeder positions at Leamington TS, and protection upgrades for in-service Kingsville DG transferred to Leamington TS.

With the establishment of Leamington TS, load will be transferred from Kingsville TS to the new station, such that the Kingsville TS load will be reduced to about 50 MW. As discussed in the IRRP report, this presents an opportunity to downsize the station from four transformers to two transformers, and would result in a combined supply capability in the Kingsville-Leamington area of 210 MW.

Figure 7-2 is a preliminary plan for the transfer of Kingsville TS feeders to Leamington TS. Feeders which are shown in blue will be completely transferred to Leamington TS, and the ones shown in green will be partially transferred to Leamington TS.

7.1.2 Recommended Plan and Current Status

Hydro One filed an application on January 22, 2014 with the OEB under Section 92 of the OEB Act for an order granting leave to construct approximately 13 km of new 230 kV transmission lines on steel lattice towers on a new right of way in the Windsor-Essex area and the installation of optic ground wire for system telecommunication purposes on existing C21J/C23Z towers near Leamington Junction and on new 230 kV towers. The application included a request for OEB approval of the methodology for allocating project cost to Hydro One Distribution, embedded LDCs and Sub-Transmission class customers.

On February 12, 2015, Hydro One filed an updated application that included the new 230/27.6 kV Leamington Transformer Station (Leamington TS). The OEB decided that the proceeding would be addressed in two phases. Phase 1 would only deal with the leave to construct application and Phase 2 of the proceeding would deal with cost allocation. Phase 1 of the SECTR S.92 proceeding has concluded and the "Leave to Construct" approval was granted by the OEB on July 16, 2015. The expected in-service date for the SECTR Project is June 2018. Phase 2 of the proceeding is continuing via an OEB policy review rather than the originally planned adjudicative process.

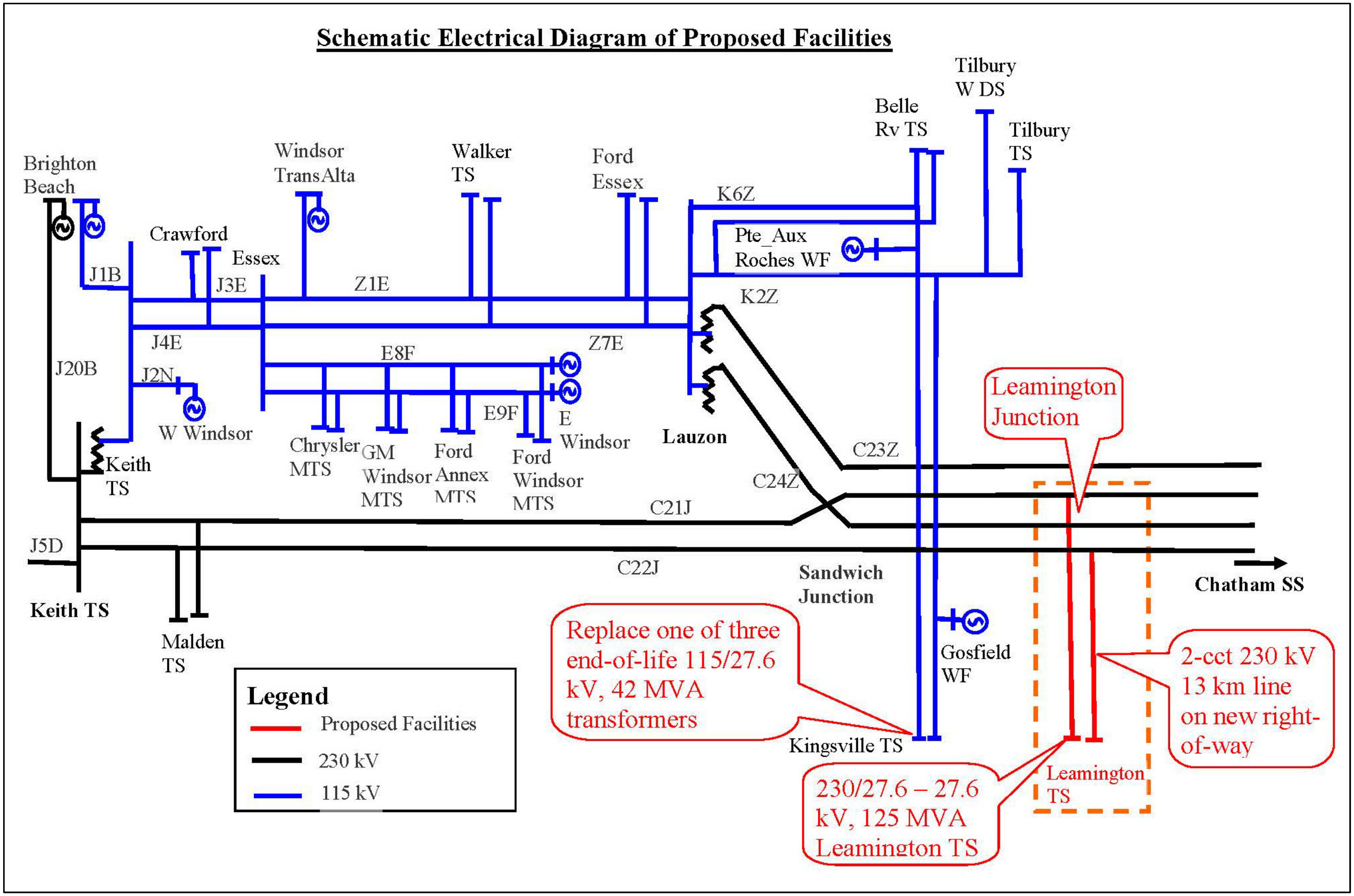


Figure 7-1 Schematic Electrical Diagram of the Proposed Facilities

Figure 7-2 Preliminary Distribution Feeder Plans for SECTR Project

7.2 Keith TS End-of-Life Auto-Transformer Replacement

7.2.1 Description

Keith TS is equipped with 2-230/115 kV 115 MVA autotransformers. These autotransformers are 1950's vintage and near end-of-life and require replacement.

7.2.2 Recommended Plan and Current Status

Due to SECTR project additional capacity will not be required and the end-of-life autotransformers at Keith TS will be replaced with equivalent like-for-like 125 MVA units. The expected in-service date is 2020. There are no cost implications for the LDCs.

7.3 Kingsville TS End-of-Life Transformer Replacement

7.3.1 Description

Kingsville TS is equipped with 4-115/27.6 kV 25/33/42 MVA transformers. One of these transformers was recently replaced, but the other three are 1950's vintage and will require replacement in the near future.

Due to SECTR project and the associated reduction in load at Kingsville TS, the station may be downsized and reconfigured as a two-transformer station. Hydro One Distribution is further reassessing to justify retaining the four-transformer arrangement if they receive additional request for connections at Kingsville area.

7.3.2 Recommended Plan

Hydro One Distribution to complete their connection capacity assessment as part of distribution system planning before Q3 2016 so that replacement and reconfiguration plan can be finalized by Hydro One in a timely manner.

7.4 Gordie Howe International Bridge (GHIB)

7.4.1 Description

The Gordie Howe International Bridge (GHIB) is a construction project under a bi-lateral agreement between the federal governments of Canada and the USA, and the governments of Ontario and Michigan, to construct a new border crossing between Windsor and Detroit. It will comprise a 12 km westerly extension of Hwy 401 to a site near Keith Transformer Station, where a new customs plaza and a new bridge over the Detroit River will be constructed. The highway will be extended by the Ministry of Transportation of Ontario (MTO), while the customs plaza and the bridge will be constructed by Transport Canada.

The GHIB project is multi-faceted in its impacts on Hydro One facilities and operations at Keith TS including: transmission lines, fiber lines and feeders relocation; insulation contamination due to salt spray effects from new bridge; relocation of access routes; possible security issues for staff accessing and working at the station; impacts on existing utilities (water/sewer/gas). In addition, the GHIB project will reduce the footprint of the station and encumber egress from the station. Consequently, this project will impact future expansion work at the station and possibly limit the extent to which the station can be developed relative to its ultimate plan development over the long term.

7.4.2 Recommended Plan and Current Status

In order to mitigate these impacts, as illustrated in Figure 7-3 below, additional real estate is required for future expansion to the north of McKee Rd. The existing transmission lines and feeders will also need to egress the station via underground cables so as not to interfere with the bridge operations.

The cost of this project will be fully recovered from the Windsor Detroit Bridge Authority (WDBA). A Transmission Assets Modification Agreement (TAMA) with the WDBA is expected to be finalized by early January 2016. Approvals for executing the project are expected by March 2016 for a planned in-service date by the end of 2018.

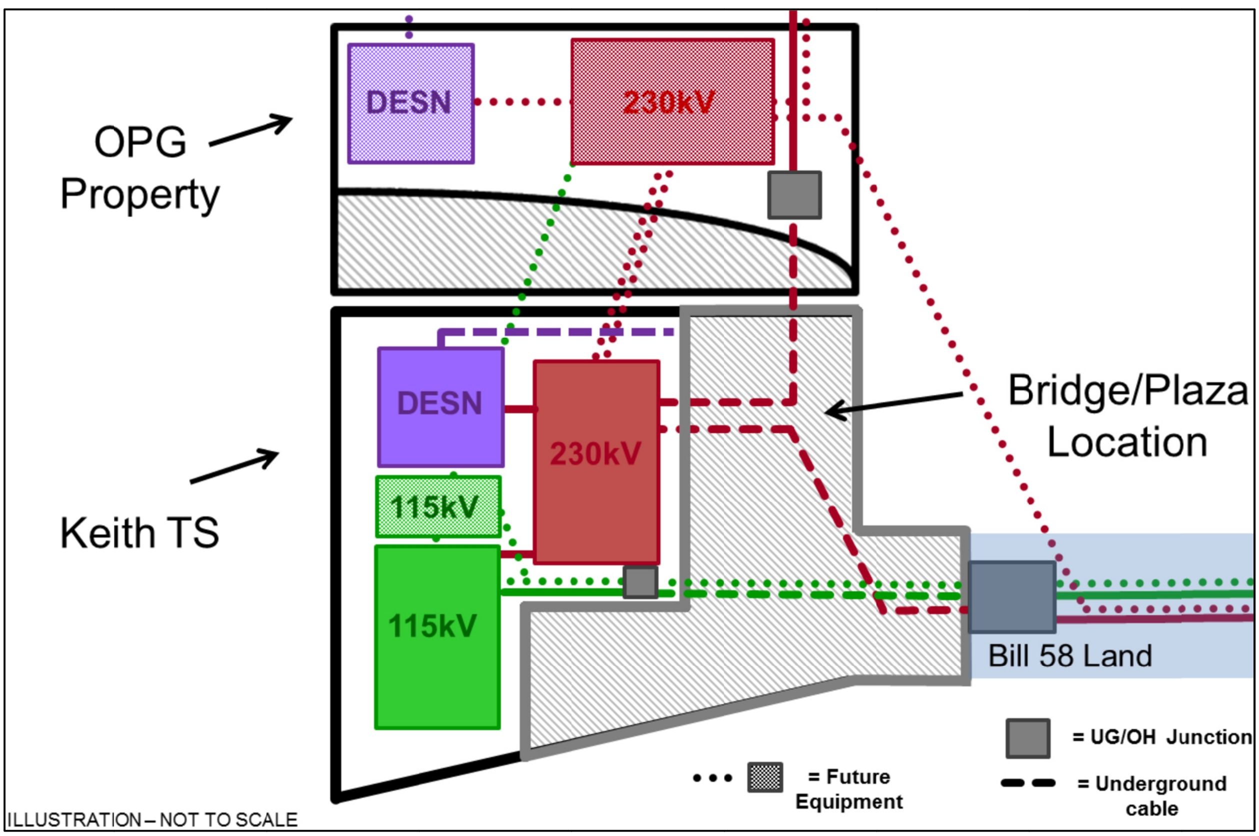


Figure 7-3 Gordie Howe International Bridge (GHIB) Project

8. OTHER PROJECTS

There are other wires projects that are currently under development and pending decision in the Windsor-Essex Region. These projects are local in nature and being planned and developed by Hydro One and relevant LDC as discussed below.

8.1 Malden TS Additional Feeder Positions

8.1.1 Description

Due to the load increase that's expected from the planned Detroit River International Crossing work and local highway construction, Essex Power has identified a need for two additional 28 kV feeder positions to be constructed at Malden TS.

The Malden transformer station is currently equipped with two 75/125 MVA transformers, 12 feeder positions and two capacitor banks and this plan involves expanding the station to 14 feeders. The two transformers at Malden TS were recently replaced, and there is additional capacity available at the station to meet the load requirement of the customer.

Based on a preliminary estimate the following will be the cost for the different layouts:

- Installation of two 28kV feeder breaker positions with feeder tie with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $1.1M
- Installation of one 28kV feeder breaker position with no feeder tie with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $875k
- Installation of one 28kV feeder breaker position with a break before make connection to alternate bus with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $925k

8.1.2 Recommended Plan and/or Current Status

The above options have been provided to Essex Powerlines Corp. Hydro One is awaiting its decision on the preferred option expected to be made in 2016.

8.2 Tilbury TS Transformer End-of-Life Replacement

8.2.1 Description

Tilbury West HVDS and Tilbury TS are both supplied from 115 kV circuit K2Z and are adjacent to each other. The two stations supply the Town of Tilbury and surrounding area. Tilbury West HVDS consists of 2 x 15/20/25 MVA, 115/27.6 kV transformers of 1980's vintage with two feeder positions; and Tilbury TS consists of 1 x 6/8 MVA 115/27.6 kV transformer of 1950's vintage with one feeder position. The

2014 peak load at Tilbury TS was 1.0 MW, and 16 MW at Tilbury West HVDS. The future load levels over the next 10 years at these stations are not expected to grow significantly.

Tilbury TS is near its end-of-life, and a decision to replace or retire should be made by 2017. Following three options are under consideration for Tilbury TS:

(1) Transfer Tilbury TS load (M1 feeder) to Tilbury West DS and decommission Tilbury TS at a cost of about $1.7M. This option is feasible as there is sufficient capacity at Tilbury West HVDS to accommodate both the Tilbury West HVDS forecast load and the Tilbury TS forecast load into the long term. Further, Tilbury West HVDS has sufficient capacity to accommodate its existing DG connections plus the existing 5 MW solar DG currently connected to Tilbury TS.
(2) Refurbish Tilbury TS at a cost of about $5M. This option would retain the supply capacity level and supply diversity that currently exists.
(3) Build a new DESN station at Tilbury TS with dual 115kV circuit supply from the K2Z and K6Z for an expected cost of about $20M. This would include building the 115kV line out from Tilbury Junction to the TS and a complete new station.

8.2.2 Recommended Plan and Current Status

Option 1 is the least cost alternative. It is recommended that Hydro One will have further discussions with the LDCs regarding these options and associated costs. These discussions are expected in 2016, and a decision is expected to be made by no later than 2017. Project construction is planned to commence in 2018 for an expected in-service in 2019. Depending on the option selected, costs may have to be recovered from the LDCs consistent with the TSC.

8.3 Keith TS T1 Transformer End-of-Life Replacement

8.3.1 Description

Keith TS transformer T1 (25/33/42 MVA 115/27.6 kV) is of 1950's vintage and it is approaching end-of-life. EnWin is the only LDC supplied from this Keith T1 and exclusively serves a single customer Nemak. The peak load was 8 MW in 2014. The load growth is expected to remain at this level in the long-term.

There is sufficient capacity at the Keith DESN station to accommodate both the forecast at Keith DESN load plus the forecast Keith TS T1 load over the next 10 years.

Following three possible options are considered to address the end-of life issue for Keith TS T1:

(1) Replace Keith TS T1.
(2) Transfer Keith TS T1 load to Keith T22/T23 DESN station.
(3) Resupply Nemak from another EnWin feeder connected to Keith T22/T23 DESN.

8.3.2 Recommended Plan and Current Status

It is recommended to develop cost estimates for each of the option. Following that Hydro One will initiate discussions with EnWin to review the options and decide on a preferred option.

Cost estimates are expected in Q1 of 2016 and selection of a preferred option is expected before the end of 2016. Discussions will then ensue with Hydro One and EnWin regarding planned construction dates.

9. CONCLUSION

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE WINDSOR-ESSEX REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report provides a single consolidated source of information for infrastructure plans in the Windsor-Essex Region. It develops and outlines a plan for investments in transmission and/or distribution facilities to meet the electricity needs within the region. The RIP report was developed in collaboration of a Technical Working Group consisting of representation from the LDCs in the region, the IESO, and led by Hydro One consistent with the requirements set out in the TSC, DSC and the PPWG report.

This report highlights several near-term needs in the region for which implementation plans have already been developed and are planned for completion in the next five years. Table 9-1 provides a status of these projects along with their cost and timelines. Projects requiring further planning on scoping and pending decisions on the preferred alternative are provided in Table 9-2. Over the next five years, the total transmission and distribution investments associated with these projects is approximately $215M - $225M.

Table 9-1 Project Under Development

Project/Plan	Cost	I/S	Performed by
Supply to Essex County Transmission Reinforcement "SECTR TX"	$77.4 Million	March 2018	Hydro One
Supply to Essex County Transmission Reinforcement "SECTR DX"	$19.3 Million	March 2018 (first stage)	Hydro One Distribution
Replacement of Keith end-of-life autotransformers	$45 Million	2020	Hydro One
Replacement of Kingsville end-of-life transformers	$12 Million	2018	Hydro One
230kV/115kV circuit and 27.6kV feeder reconfiguration at Keith TS due to Gordie Howe International Bridge (GHIB) Project	$63 Million	October 2018	Hydro One
Transformer replacement and station refurbishment at Crawford TS	$8.46 Million	December 2016	Hydro One

Table 9-2 Project Pending Decision

Project/Plan	Cost	I/S	Performed by
Additional feeder position at Malden TS	TBD	TBD	Hydro One
Replacement of Tilbury end-of-life transformer	TBD	2019	Hydro One
Keith TS end-of-life T1 Transformer	TBD	TBD	Hydro One

There are no long-term needs in this region that requires plans to be developed at this time. As with any region, the Windsor-Essex Region is monitored as part of Hydro One and LDC operations. Should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

10. REFERENCES

[1] Independent Electricity System Operator. "Windsor-Essex Region Integrated Regional Resource Plan". April 28, 2015.
http://www.ieso.ca/Documents/Regional-Planning/Windsor_Essex/2015-Windsor-Essex-IRRP-Report.pdf

APPENDIX A. GROSS FORECAST BY SUBSYSTEM & STATION

J3E/J4E Sub-System	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (extreme weather)		*Forecast*																			
Kingsville TS	158	133	137	141	145	146	147	148	149	150	151	152	153	155	156	157	158	159	160	161	162
Belle River TS	59	46	46	47	48	49	50	51	52	53	53	54	55	56	57	58	59	60	61	62	63
Tilbury West DS	34	17	17	17	17	18	18	18	18	18	19	19	19	19	19	19	19	19	19	20	20
Tilbury TS	10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Lauzon TS	225	191	193	195	197	199	201	203	204	206	208	209	211	213	215	217	219	221	223	224	226
Walker TS #1	99	71	79	76	77	77	78	78	79	79	80	80	81	81	82	82	83	83	84	84	85
Walker TS #2	99	95	111	92	92	93	93	94	94	95	96	96	97	97	98	99	99	100	100	101	102
Essex TS	116	55	63	73	73	74	74	75	75	76	76	77	77	78	78	78	79	79	80	80	81
Crawford TS	90	83	84	84	85	85	86	86	87	87	88	88	89	89	90	90	91	91	92	93	93
Chrysler	65	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Ford Powerhouse	65	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
General Motors	43	2	0	14	14	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15
Ford Annex	43	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Ford Essex Engine Plant	43	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Subtotal	**N/A**	**769**	**807**	**816**	**824**	**830**	**836**	**843**	**849**	**854**	**860**	**866**	**872**	**878**	**884**	**891**	**897**	**903**	**909**	**916**	**922**

Additional Stations in the Windsor-Essex Region	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (extreme weather)		*Forecast*																			
Keith TS T1	54	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Keith TS T22/T23	114	68	67	67	67	67	67	67	68	68	68	68	68	68	68	68	68	69	69	69	69
Malden TS	200	117	118	119	120	120	121	122	124	124	125	126	127	127	128	129	130	131	131	132	133
Windsor Essex Total	**N/A**	**962**	**1000**	**1009**	**1019**	**1026**	**1033**	**1041**	**1048**	**1055**	**1061**	**1068**	**1074**	**1082**	**1089**	**1096**	**1104**	**1111**	**1118**	**1125**	**1133**

Kingsville-Leamington Sub-system	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (weather normal)		*Forecast*																			
Total	**N/A**	**155**	**160**	**165**	**169**	**172**	**174**	**177**	**178**	**181**	**183**	**186**	**188**	**191**	**193**	**196**	**199**	**201**	**204**	**206**	**209**

APPENDIX B. CONSERVATION ASSUMPTIONS BY SUBSYSTEM & STATION

J3E/J4E Sub-System	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation		Forecast																			
Kingsville TS	158	1	2	3	3	4	6	9	10	11	12	14	15	16	18	20	21	22	24	25	26
Belle River TS	59	0	1	1	1	1	2	3	3	3	4	4	5	5	5	6	6	7	7	8	8
Tilbury West DS	34	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3
Tilbury TS	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lauzon TS	225	1	3	4	4	5	8	11	12	13	14	17	18	19	21	23	24	26	28	29	30
Walker TS #1	99	1	1	2	2	2	4	5	5	6	6	7	8	8	9	10	11	11	12	13	13
Walker TS #2	99	1	1	2	2	3	4	6	6	7	8	9	10	10	11	13	13	14	15	16	16
Essex TS	116	0	1	1	1	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	9
Crawford TS	90	1	1	1	2	2	3	4	4	5	5	6	7	7	8	9	9	10	10	11	11
Chrysler	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Powerhouse	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General Motors	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Annex	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Essex Engine Plant	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Subtotal	**N/A**	**5**	**10**	**14**	**16**	**20**	**31**	**41**	**45**	**50**	**55**	**64**	**69**	**75**	**81**	**89**	**94**	**100**	**107**	**114**	**115**

Additional Stations in the Windsor-Essex Region	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation		Forecast																			
Keith TS T1	54	0	1	1	1	1	2	3	3	3	3	4	4	5	5	6	6	7	7	8	8
Keith TS T22/T23	114	0	1	1	1	1	2	3	3	3	3	4	4	5	5	6	6	7	7	8	8
Malden TS	200	1	2	2	3	3	5	7	7	8	9	11	11	12	14	15	16	17	18	19	19

Windsor Essex Total	**N/A**	**7**	**12**	**18**	**20**	**26**	**40**	**53**	**58**	**65**	**72**	**83**	**89**	**97**	**105**	**116**	**122**	**130**	**139**	**148**	**149**

Kingsville-Leamington Sub-system	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation		Forecast																			
Total	**N/A**	**1**	**2**	**3**	**3**	**4**	**6**	**9**	**10**	**11**	**12**	**14**	**15**	**16**	**18**	**20**	**21**	**22**	**24**	**25**	**26**

APPENDIX C. DISTRIBUTED GENERATION ASSUMPTIONS BY SUBSYSTEM & STATION

J3E/J4E Sub-System Distributed Generation	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Kingsville TS	158	15	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Belle River TS	59	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Tilbury West DS	34	2	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Tilbury TS	10	2	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Lauzon TS	225	8	16	18	19	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Walker TS #1	99	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Walker TS #2	99	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Essex TS	116	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Crawford TS	90	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Chrysler	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Powerhouse	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General Motors	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Annex	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Essex Engine Plant	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	**N/A**	**35**	**59**	**64**	**66**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**

Additional Stations in the Windsor-Essex Region Distributed Generation	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Keith TS T1	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Keith TS T22/T23	114	21	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Malden TS	200	9	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Windsor Essex Total	**N/A**	**65**	**63**	**69**	**71**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**

Kingsville-Leamington Sub-system Distributed Generation	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Total	**N/A**	**15**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**

APPENDIX D. REFERENCE PLANNING FORECAST BY SUBSYSTEM & STATION

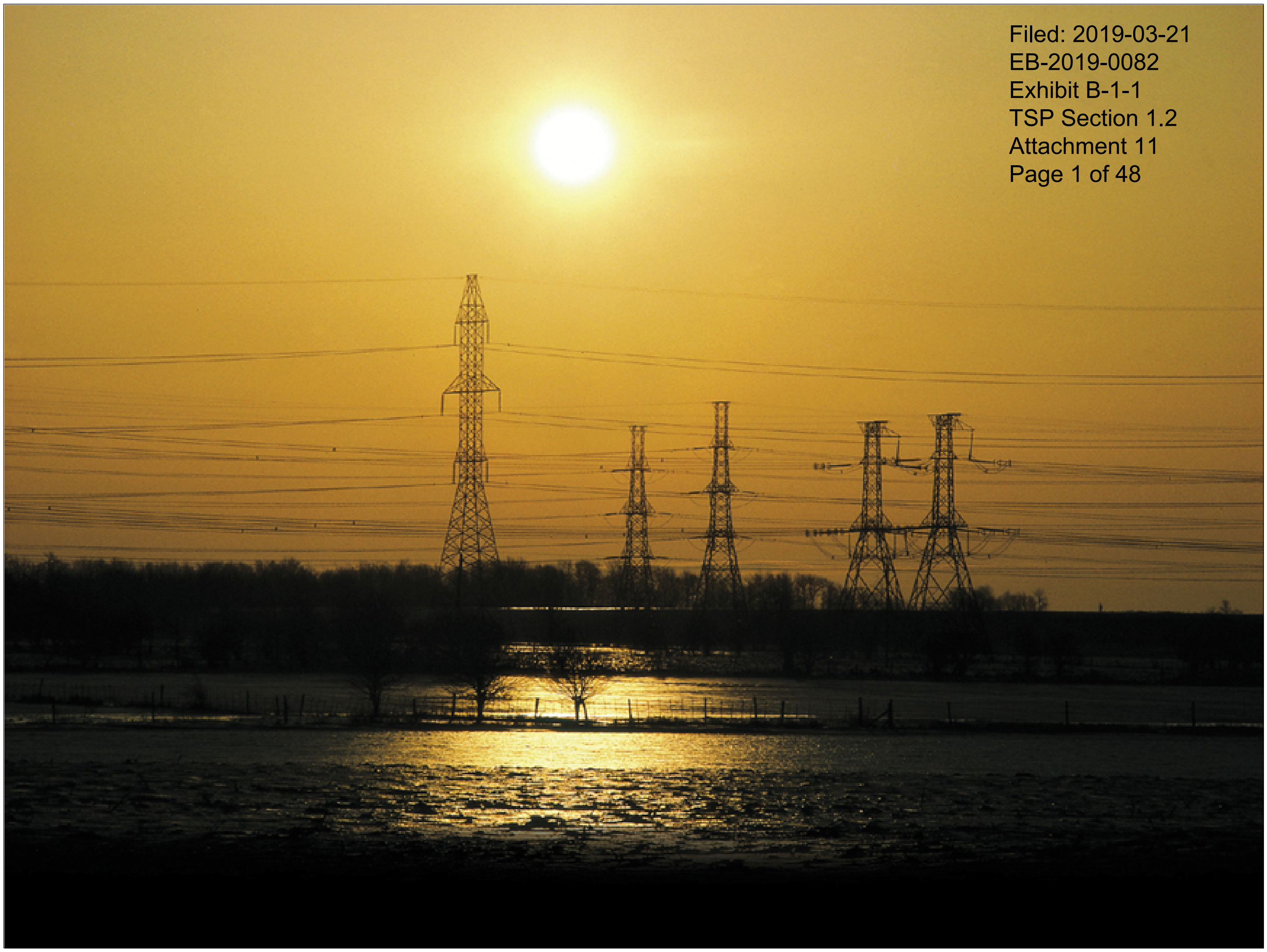
J3E/J4E Sub-System	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (extreme weather)			Forecast																		
Kingsville TS	158	133	114	117	121	121	120	118	118	118	118	117	117	118	117	116	116	116	115	115	115
Belle River TS	59	46	43	44	44	45	45	45	46	47	46	47	47	48	49	49	50	50	51	51	52
Tilbury West DS	34	17	7	7	7	8	7	7	7	7	8	7	7	7	7	7	7	7	6	7	7
Tilbury TS	10	1	-6	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7
Lauzon TS	225	191	174	173	174	174	173	172	172	173	174	172	173	174	174	174	175	175	175	175	176
Walker TS #1	99	71	76	72	73	73	72	71	72	71	72	71	71	71	71	70	70	70	70	69	70
Walker TS #2	99	95	109	89	89	89	88	87	87	87	87	86	86	86	86	85	85	85	84	84	85
Essex TS	116	55	62	71	71	71	70	71	70	71	70	71	70	71	70	70	70	70	70	70	71
Crawford TS	90	83	82	82	81	81	81	80	81	80	81	80	80	80	80	79	80	79	80	80	80
Chrysler	65	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Ford Powerhouse	65	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
General Motors	43	2	0	14	14	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15
Ford Annex	43	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Ford Essex Engine Plant	43	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Subtotal	**N/A**	**769**	**737**	**738**	**742**	**743**	**737**	**733**	**736**	**736**	**737**	**734**	**733**	**737**	**735**	**733**	**735**	**735**	**733**	**734**	**738**

Additional Stations in the Windsor-Essex Region	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (extreme weather)			Forecast																		
Keith TS T1	54	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Keith TS T22/T23	114	68	64	64	64	64	63	62	63	63	63	62	62	61	61	60	60	60	60	59	59
Malden TS	200	117	115	114	114	114	113	112	114	113	113	112	113	112	111	111	111	111	110	110	111
Windsor Essex Total	**N/A**	**962**	**924**	**923**	**928**	**930**	**922**	**916**	**920**	**921**	**921**	**916**	**915**	**919**	**916**	**912**	**915**	**914**	**912**	**911**	**917**

Kingsville-Leamington Sub-system	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (weather normal)			Forecast																		
Total	**N/A**	**155**	**147**	**151**	**155**	**156**	**157**	**157**	**158**	**159**	**160**	**161**	**162**	**164**	**165**	**166**	**167**	**169**	**169**	**171**	**173**

APPENDIX E. LIST OF ACRONYMS

A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
OPG	Ontario Power Generation
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme



London Area

REGIONAL INFRASTRUCTURE PLAN

August 25th, 2017

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Organizations
Independent Electricity System Operator
Entegrus Inc.
Erie Thames Power Lines Corporation
London Hydro Inc.
St. Thomas Energy Inc.
Tillsonburg Hydro Inc.
Hydro One Networks Inc. (Distribution)

DISCLAIMER

This Regional Infrastructure Plan (“RIP”) report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be re-evaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, “the Authors”) make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared (“the Intended Third Parties”), or to any other third party reading or receiving the RIP report (“the Other Third Parties”), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN (“RIP”) WAS PREPARED BY HYDRO ONE NETWORKS INC. (“HYDRO ONE”) AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS OF THE LONDON AREA REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Entegrus Inc.
- Erie Thames Power Lines Corporation
- London Hydro Inc.
- St. Thomas Energy Inc.
- Tillsonburg Hydro Inc.
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB’s mandated regional planning process for the London Area Region which consists of the Strathroy Sub-Region, Greater London Sub-Region, Woodstock Sub-Region, Aylmer-Tillsonburg Sub-Region, and the St. Thomas Sub-Region. It follows the completion of the London Area Region’s Needs Assessment (“NA”) in April 2015, the London Area Region Scoping Assessment (“SA”) in August 2015, the Strathroy TS Transformer Capacity Local Plan (“LP”) in September 2016, the Greater London Sub-Region Integrated Regional Resource Plan (“IRRP”) in January 2017, and the Woodstock Sub-Region Restoration Local Plan (“LP”) in May 2017.

This RIP provides a consolidated summary of needs and recommended plans for the entire London Area Region. Needs which are to be addressed include:

- Load restoration in Woodstock Sub-Region
- Load restoration in Greater London Sub-Region
- Voltage constraints, thermal constrains and delivery point performance in Aylmer-Tillsonburg Sub-Region

The major infrastructure investments planned for the region over the near and mid-term, as identified in the regional planning process are given below.

No.	Project	I/S Date	Estimated Cost[1]
1	Distribution System Upgrades in the Greater London Sub-Region	2023	$1.8-4M ($180/kW)
2	Wonderland TS Reinvestment: Replace transformer T5	2022	$15-20M

As per the Regional Planning process, the Regional Plan will be reviewed and/or updated at least once every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

[1] Costs presented are preliminary estimate and may change resulting from clarification of scope and through detailed cost estimating.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE LONDON AREA REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Independent Electricity System Operator, Entegrus Inc., Erie Thames Power Lines Corporation, London Hydro Inc., St. Thomas Energy Inc., Tillsonburg Hydro Inc., and Hydro One Networks Inc. (Distribution) in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The London Area is located in South Western Ontario and includes all or part of the following Counties, and Cities: Oxford County, Middlesex County, Elgin County, Norfolk County, the City of Woodstock, the City of London, and the City of St. Thomas. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

The region also includes the following First Nations: Chippewas of the Thames, Oneida Nation of the Thames, and Munsee-Delaware Nation.

Electrical supply to the London Area is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Longwood Transformer Station (TS) and 230/115 kV autotransformers at Buchanan TS and Karn TS. There are fifteen Hydro One step-down TS's, four direct transmission connected load customers and three transmission connected generators in the London Area. The distribution system consists of voltage levels 27.6 kV and 4.16kV.The boundaries of the Region are shown in Figure 1-1 below.

Within the current regional planning cycle, four regional assessments have been conducted for the London Area Region. The findings of these studies are an input to the RIP and the studies are as follows:

1. IESO's Greater London Sub-Region Integrated Regional Resource Plan – January, 2017
2. Hydro One's Woodstock Sub-Region Restoration Local Plan - May, 2017
3. Hydro One's Strathroy TS Transformer Capacity Local Plan – September, 2016
4. Hydro One's London Area Region Needs Assessment Report – April, 2015

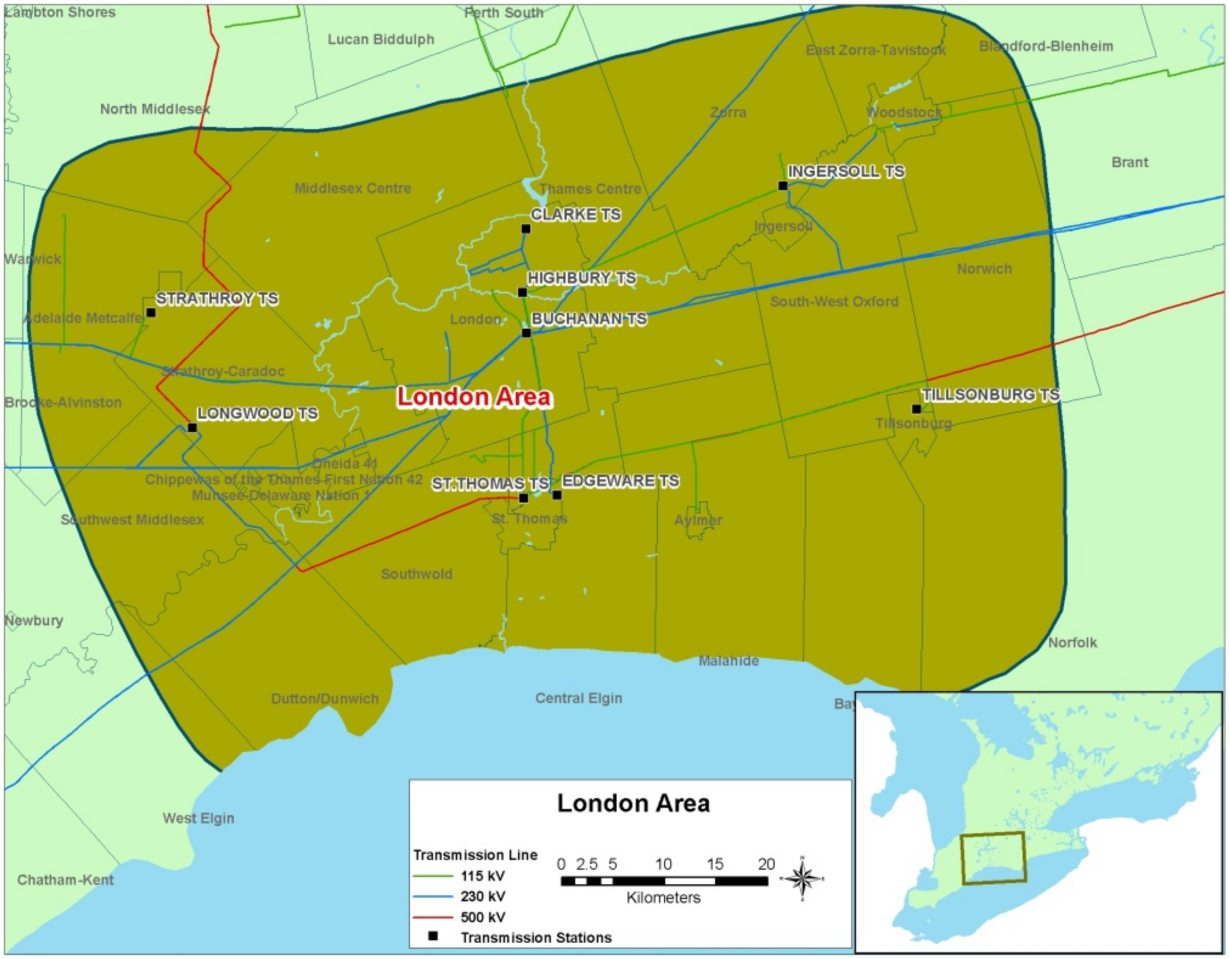

Figure 1-1 London Area Region

1.1 Scope and Objectives

This RIP report examines the needs in the London Area Region and its objectives are to:

- Confirm supply needs identified in previous planning phases;
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop wires plans to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2016-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2016-2025 period and a wires plan to address them;
- Consideration of long-term needs identified in the Greater London Sub-Region IRRP

As per the Regional Planning process, the Regional Plan for the region will be reviewed and/or updated at least every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the regional characteristics
- Section 4 describes major High Voltage transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the regional needs
- Section 7 describes the needs and provides the alternatives and preferred solutions
- Section 8 provides the conclusion and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is performed at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning evaluates supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115kV and 230kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[2] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, and needs are local in nature, an assessment is undertaken for any necessary investments directly by the LDCs (or customers) and the transmitter through a Local Plan ("LP"). These needs are local in nature and can be best addressed by a straight forward wires solution. The Working Group recommends a LP undertaking when needs are a) local in nature b) limited to investments in wires (transmission or distribution) solutions c) do not require upstream transmission investments d) do not require plan level stakeholder engagement and e) do not require other approvals such as Leave to Construct (S92) approval or Environmental Approval.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. If there are needs that do not require regional coordination, the Working Group can recommend them to be undertaken as part of the LP approach discussed above. Otherwise, the approach is to complete either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-

[2] Also referred to as Needs Screening.

region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee ("LAC") in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

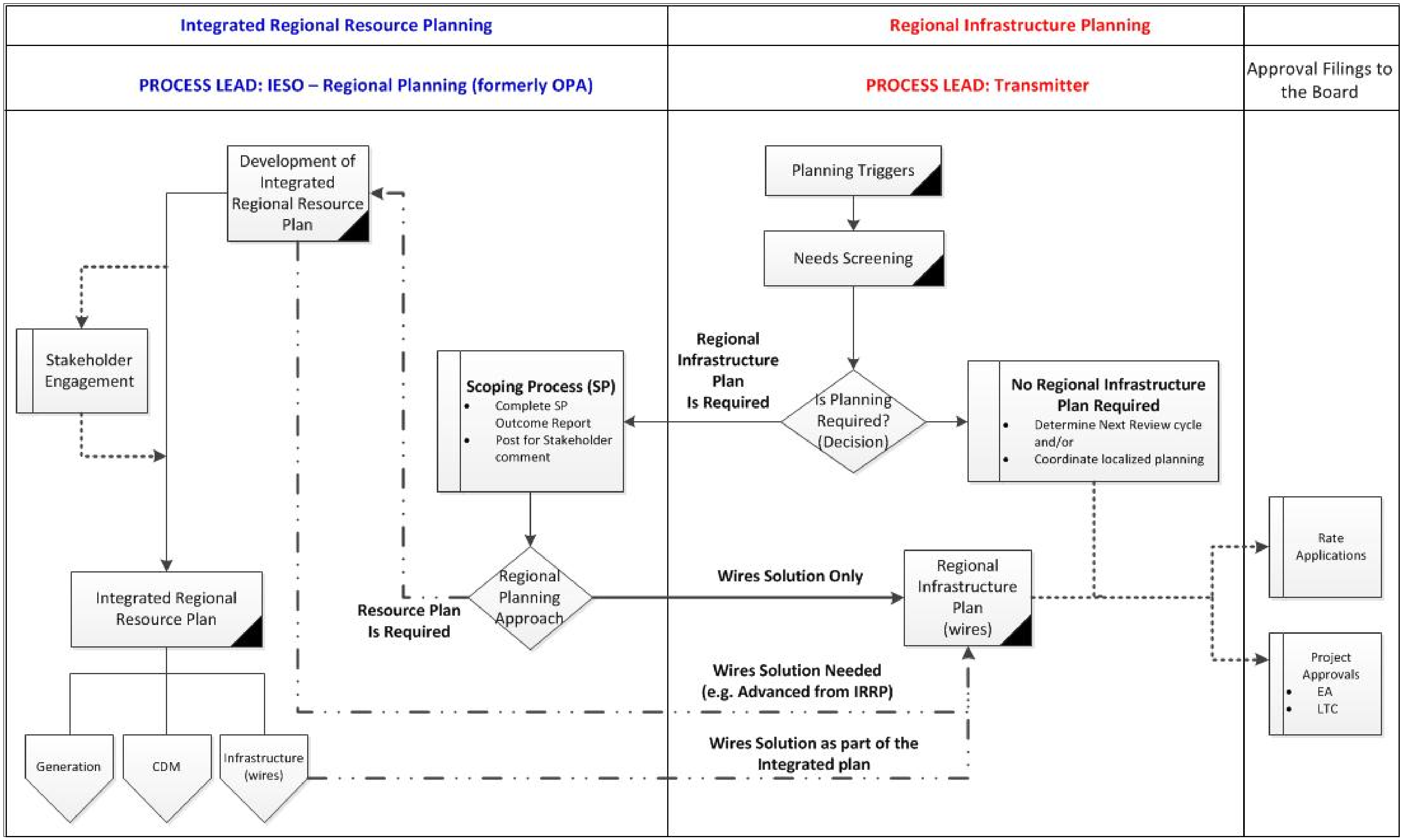

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects the following information and reviews it with the Working Group to reconfirm or update the information as required:

    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation ("DG") or CDM programs;
    - Existing area network and capabilities including any bulk system power flow assumptions;
    - Other data and assumptions as applicable such as asset conditions, load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

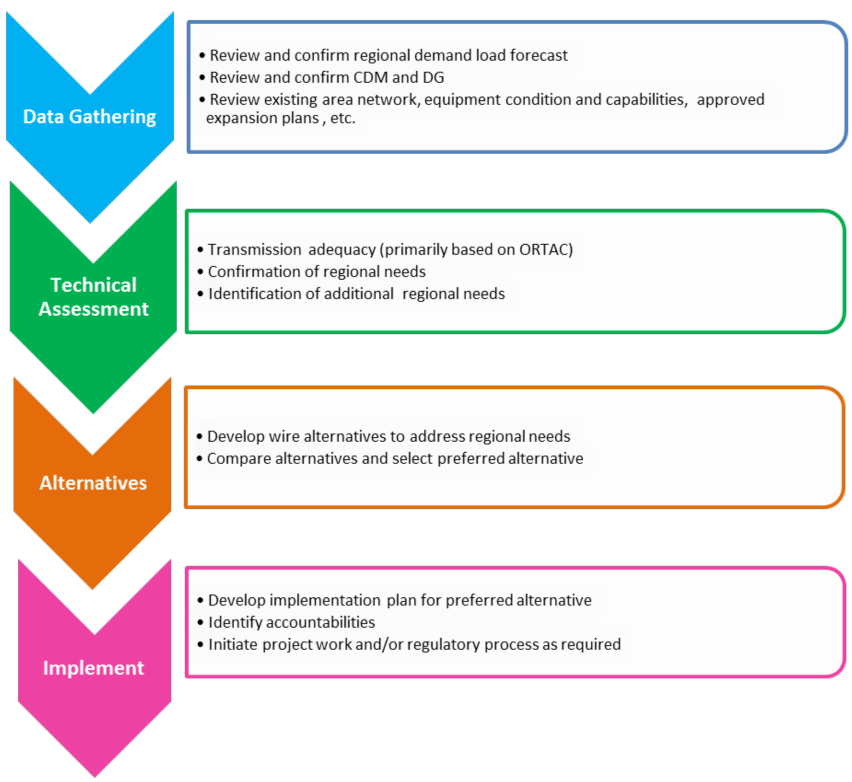

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE LONDON AREA IS LOCATED IN SOUTH WESTERN ONTARIO AND INCLUDES ALL OR PART OF OXFORD COUNTY, MIDDLESEX COUNTY, ELGIN COUNTY, NORFOLK COUNTY, THE CITY OF WOODSTOCK, THE CITY OF LONDON, AND THE CITY OF ST. THOMAS. THE REGION ALSO INCLUDES THE FOLLOWING FIRST NATIONS: CHIPPEWAS OF THE THAMES, ONEIDA NATION OF THE THAMES, AND MUNSEE-DELAWARE NATION. LONDON AREA REGION IS DIVIDED INTO FIVE SUB-REGIONS: STATHROY SUB-REGION, GREATER LONDON SUB-REGION, WOODSTOCK SUB-REGION, AYLMER-TILLSONBURG SUB-REGION, AND THE ST. THOMAS SUB-REGION.

Electrical supply to the London Area Region is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Longwood Transformer Station (TS) and 230/115 kV autotransformers at Buchanan TS and Karn TS. There are fifteen Hydro One step-down TS', four direct transmission connected load customers and three transmission connected generators. The region is summer-peaking and has a peak demand of approximately 1,250 MW including direct transmission connected customers. A map of the London Area Region (highlighting the sub-regions) and a single line diagram of the transmission system are shown in Figure 3-1 and Figure 3.2.

Table 3-1 Sub-Region Details

Sub-Region	Station Name (DESN)	Voltage Level (kV)	Supply Circuits	Connected Customers
Strathroy Sub-Region	Strathroy TS (T7/T8)	230/27.6	W2S, S2N	• Hydro One Distribution • Entegrus
	Longwood TS (T13/T14)	230/27.6	L24L, L26L	• Hydro One Distribution
Greater London Sub-Region	Talbot TS (T1/T2, T3/T4)	230/27.6	W36, W37	• London Hydro • Hydro One Distribution
	Clark TS (T3/T4)	230/27.6	W36, W37	
	Wonderland TS (T5/T6)	230/27.6	N21W, N22W	
	Buchanan TS (T13/T14)	230/27.6	W42L, W43L	
	Nelson TS (T1/T2)	115/13.8	W5N, W6NL	
	Highbury TS (T3/T4)	115/27.6	W6NL, W9L	
Woodstock Sub-Region	Ingersoll TS (T5/T6)	230/27.6	M31W, M32W	• Hydro One Distribution • Erie Thames Powerlines
	Woodstock TS (T1/T2)	115/27.6	K7, K12	
	Commerceway TS (T1/T2)	115/27.6	K7, K12	
Aylmer Sub-Region	Aylmer TS (T2/T3)	115/27.6	WT1A, W8T, T11T	• Hydro One Distribution, • Erie Thames Powerlines • Tillsonburg Hydro
	Tillsonburg TS (T1/T3)	115/27.6	WT1T, W8T, T11T	
St.Thomas Sub-Region	St. Thomas TS	115/27.6kV	W3T, W4T, T11T	Station is planned for decommissioning, no remaining customers connected.
	Edgeware TS	230/27.6kV	W45LS, W44LC	• Hydro One Distribution • St. Thomas Energy • London Hydro

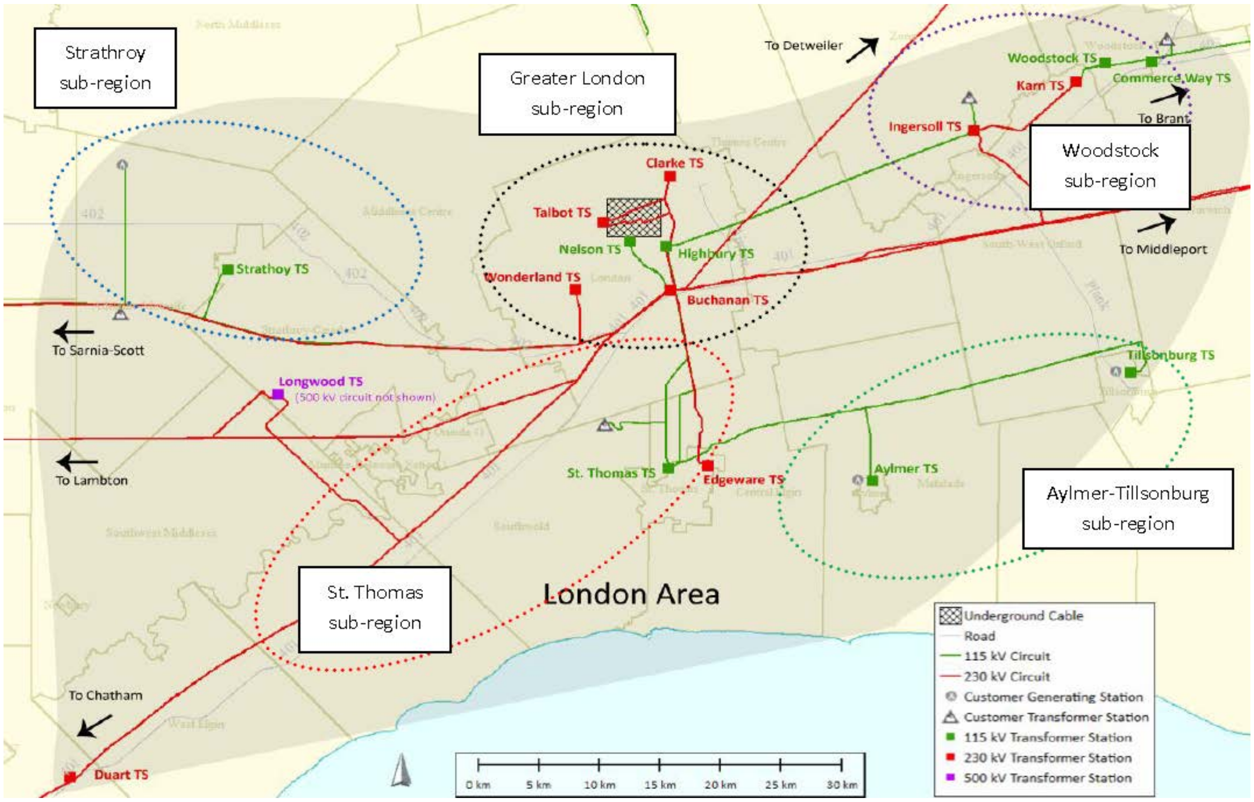

Figure 3-1 London Area Region – Supply Areas

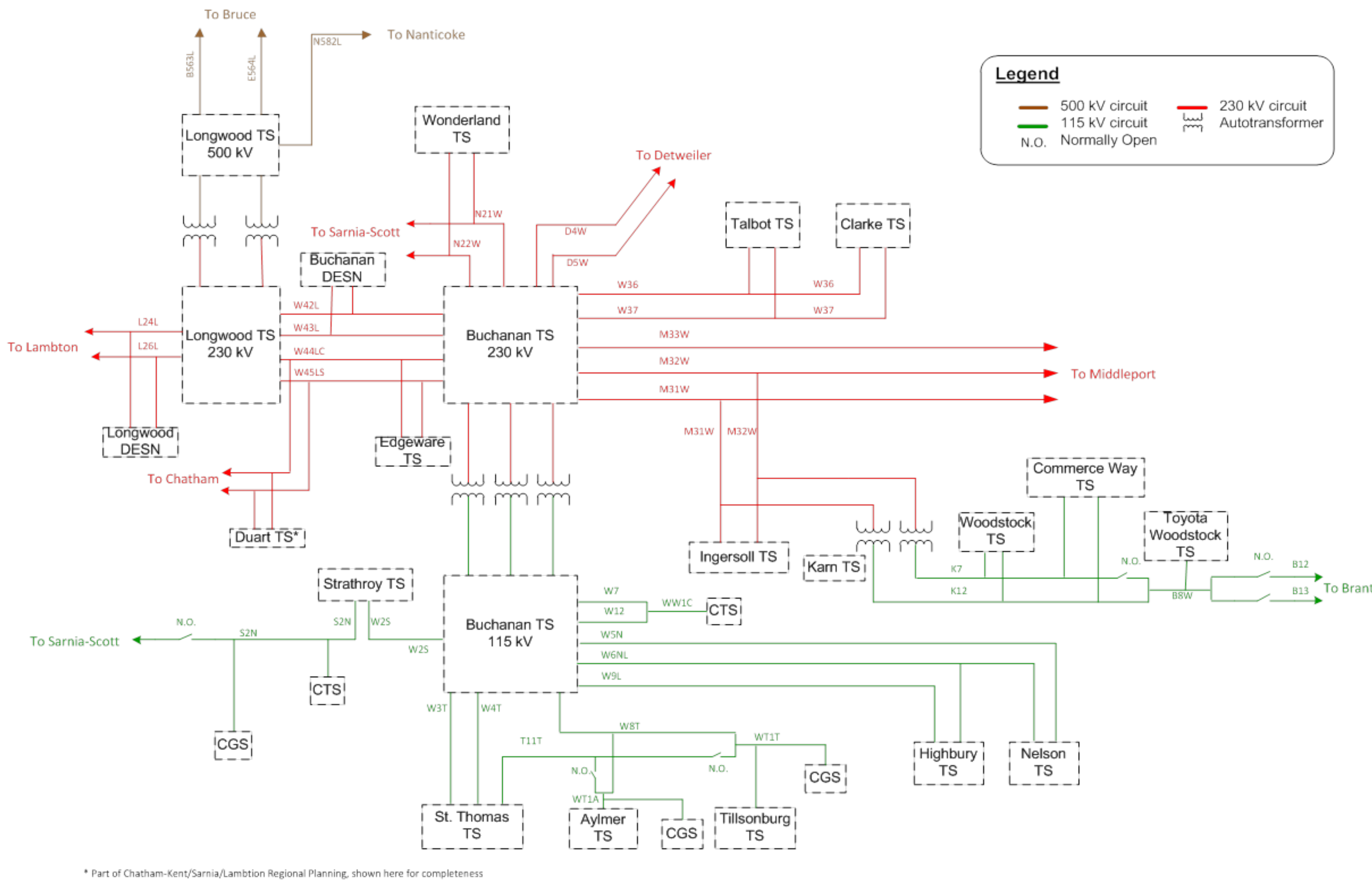

Figure 3-2 London Area Region Single Line Diagram

4. TRANSMISSION PROJECTS COMPLETED OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE LONDON AREA REGION.

A brief listing of the major projects completed over the last 10 years is given below:

- Talbot TS Expansion (2007) – Expansion of the existing Talbot TS and construction of a second 50/83 MVA 230/27.6 kV transformer station to alleviate load from existing transformer stations in the area, which were loaded beyond its capacity and provide additional capacity for the load growth in the London area.
- Highbury TS Transformer Replacement (2009) – Like-for-like replacement of 50/83 MVA 115/27.6 kV transformer T4 that was over 60 years old and nearing end-of-life.
- Commerce Way TS (2010) – Construction of a new 50/83 MVA 115/27.6 kV Commerce Way transformer station to alleviate load from Woodstock TS, which was loaded beyond its capacity and provide additional capacity for the load growth in the Woodstock area.
- Strathroy TS Transformer Replacement (2012) – Like-for-like replacement of 25/42 MVA 115/27.6 kV transformer T2 due to failure.
- Ingersoll TS Transformer Replacement (2012) – Like-for-like replacement of 75/125 MVA 230/27.6 kV transformers T5 & T6 that were approximately 35 years old. The transformers were identified to have a design weakness and were replaced to mitigate the risk of failures, improve restoration time and maintain system performance.
- Woodstock TS Transformer Replacement (2014) – Like-for-like replacement of 50/83 MVA 115/27.6 kV transformers T1 & T2 that were approximately 50 years old and were nearing end-of-life.

The following development projects are expected to be placed in-service within the next 10 years:

1. **Aylmer TS**: is located in Southwestern Ontario and is comprised of two 11/15 MVA, 110-28 kV transformers (T2 & T3) and two 27.6 kV feeder breaker positions M1, M2. The station is supplied by a single 115kV line WT1A and it supplies Erie Thames Powerlines Corp. and Hydro One Distribution at 27.6 kV.

   The deteriorating asset condition of a significant portion of station equipment, including transformers (T2 & T3) and LV switchyard, qualifies it as a candidate for a complete station rebuild. To address the urgent need, the existing station will be replaced with a new DESN with two 25/33/42 MVA transformers. The replacement work also includes all 28kV LV switching facilities, the addition of two new feeder positions, and an upgrade to associated protection and control systems.

   This project is currently under execution and planned to be completed before end of 2017.

2. **Strathroy TS**: is located in Middlesex County in Southwestern Ontario and is comprised of two 25/33/42 MVA 110-28 kV transformers (T1 & T2) and four 27.6 kV feeder breaker positions. Strathroy TS supplies Entegrus Powerlines Inc. and Hydro One Distribution at 27.6 kV.

   Due to deteriorating asset condition, Hydro One has planned to replace the T1 transformer with similar type 42MVA transformer, replace all LV switching facilities, and upgrade associated protection and control facilities and AC/DC station ancillary infrastructure.

   This project is currently under execution and planned to be completed in 2017.

3. **Nelson TS**: is located in the City of London in Southwestern Ontario and is comprised of two DESN stations (the "T1/T2 DESN" and the "T3/T4 DESN") which are both supplied from the 115 kV circuits W5N and W6NL. The T1/T2 DESN consists of two 18/27/33 MVA, 115/ 13.8 kV transformers with two LV yards (outdoor and indoor), and the T3/T4 DESN consists of two 60/80/100 MVA, 115/ 13.8 kV transformers with two LV yards (both indoor). The T1/T2 DESN supplies about 17 MW of 13.8kV load in the London downtown area and the T3/T4 DESN supplies approximately 31 MW of 13.8 kV load, also in the London downtown area.

   The deteriorating asset condition of a significant portion of station equipment, including transformers (T1 & T2) and LV switchyard, qualifies it as a candidate for a complete station rebuild. In addition, London Hydro has requested that Hydro One rebuild the LV at 27.6kV rather than at 13.8kV so that the station can be integrated into London Hydro's 27.6kV distribution system to provide load support. As a result, Hydro one is building a new station within the existing Nelson TS yard. The new station will consist of two new 115/27.6 kV, 50/83 MVA DESNs and new LV switchyard with 8 feeder positions and 2 capacitor bank positions. All associated protection and control systems and station ancillary infrastructure will be upgraded. The work will also involve decommissioning of the existing DESN substation consisting of T1 and T2 transformers and the 13.8kV air insulated outdoor switchyard.

   This project is currently under execution and planned to be completed in 2018.

5. FORECAST AND STUDY ASSUMPTIONS

THE FORECASTS REFLECT THE EXPECTED PEAK DEMAND AT EACH STATION UNDER EXTREME WEATHER CONDITIONS, BASED ON FACTORS SUCH AS POPULATION, HOUSEHOLD AND ECONOMIC GROWTH, CONSISTENT WITH MUNICIPAL PLANNING ASSUMPTIONS.

5.1 Historical Demand

The London Area regional peak load has been relatively constant over the past 5 years (approximate decline of -0.4%).

5.2 Contribution of CDM and DG

In developing the planning forecast, the following process was used to assess the London Region:

- First, "gross demand" is established. Gross demand reflects the forecast developed and provided by the area LDCs and is influenced by a number of factors such as economic, household and population growth.
- Second, "net demand" is derived by reducing the gross demand by expected savings from improved building codes and equipment standards, customer response to time-of-use pricing, projected province-wide CDM programs, committed and forecast DG . This information is provided by the IESO.

5.3 Gross and Net Demand Forecast

Prior to the RIP's kick-off, the Working Group was asked to confirm the load forecasts for all stations in the Region provided for previous assessments. The RIP's load forecast was updated according the revised load forecasts provided by the LDCs.

The load in the London Area Region including CDM targets and DG contributions is expected to remain relatively constant over the study period (approximate growth rate of -0.3%). The growth rate varies across the region but an overall coincident net load forecast in the region is illustrated in Figure 5-1. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix B and C.

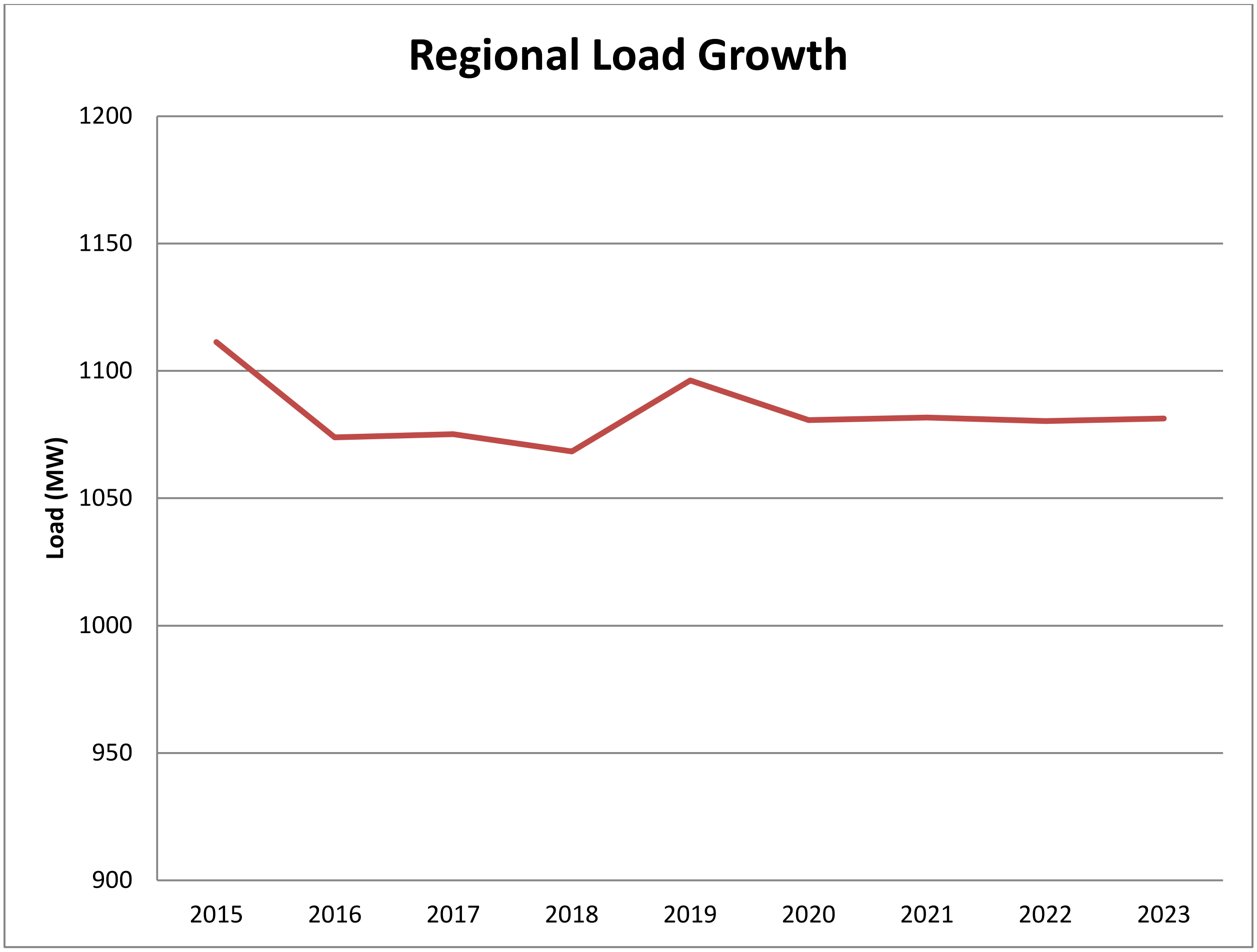

Figure 5-1 London Area Region Coincident Net Load Forecast

5.4 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2016 – 2023.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on extreme summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE LONDON AREA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, four regional assessments have been conducted for the London Area Region. The findings of these studies are an input to the RIP and the studies are as follows:

1. IESO's Greater London Sub-Region Integrated Regional Resource Plan – January, 2017[1]
2. Hydro One's Woodstock Sub-Region Restoration Local Plan - May, 2017[2]
3. Hydro One's Strathroy TS Transformer Capacity Local Plan – September, 2016[3]
4. Hydro One's London Area Region Needs Assessment Report – April, 2015[4]

The IRRP, NA, and LP studies identified a number of regional needs based on the forecast load demand over the near to mid-term. Based on the regional growth rate referred to in Section 5, this RIP reviewed the loading on transmission lines and stations in the London Area Region assuming the new Nelson TS DESN will be in-service by the end of 2018, and the new Aylmer TS DESN will be in-service by the end of 2017. Further detailed description and status of plans to meet these needs is provided in Section 7.

6.1 Transmission Line Facilities

Electrical supply to the London Area is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Longwood Transformer Station (TS) and 230/115 kV autotransformers at Buchanan TS and Karn TS. The main features of the electrical supply system in the London Area are as follows:

- Longwood TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.
- Buchanan TS and Karn TS are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.
- Fifteen step-down transformer stations supply the London Area load: Aylmer TS, Buchanan TS, Clarke TS, Commerceway TS, Edgeware TS, Highbury TS, Ingersoll TS, Longwood TS, Nelson TS, Strathroy TS, St. Thomas TS, Talbot TS, Tillsonburg TS, Wonderland TS, and Woodstock TS.
- Four Customer Transformer Stations (CTS) are supplied in the London Area: Ford Talbotville CTS, Enbridge Keyser CTS, Lafarge Woodstock CTS, and Toyota Woodstock CTS.
- There are 3 existing transmission connected generating stations in the London Area as follows:

- Suncor Adelaide GS is a 40 MW wind farm connected to 115 kV circuit west of Strathroy TS
- Erie Shores Wind Farm GS is a 99 MW wind farm connected to 115kV circuit near Tillsonburg TS
- Silver Creek GS is a 10 MW solar generator connected to 115kV circuit near Aylmer TS

The 500kV system is part of the bulk system planning conducted by the IESO and is not studied as part of this RIP

Table 6-1 provides 230 kV and 115 kV circuit network that supplies to the London Area.

Table 6-1 230 kV and 115 kV circuits network in the London Area

Voltage	Circuit Designations	Location
230 kV	N21W, N22W	Scott TS to Buchanan TS
	W42L, W43L	Longwood TS to Buchanan TS
	W44LC	Longwood TS to Chatham TS to Buchanan TS
	W45LS	Longwood TS to Spence SS to Buchanan TS
	W36, W37	Buchanan TS to Talbot TS
	D4W, D5W	Buchanan TS to Detweiler TS
	M31W, M32W	Buchanan TS to Ingersoll TS to Middleport TS
	M33W	Buchanan TS to Brantford TS
115 kV	W2S	Buchanan TS to Strathroy TS
	W5N	Buchanan TS to Nelson TS
	W6NL	Buchanan TS to Highbury TS to Nelson TS
	W9L	Buchanan TS to Highbury TS
	W7, W12 WW1C W8T T11T WT1T W3T, W4T WT1A K7, K12	Buchanan TS to CTS Buchanan TS to CTS Buchanan TS to Cranberry JCT Erie Shore Wind Farm JCT to Tillsonburg TS Buchanan TS to St. Thomas TS Aylmer TS to Lyons JCT Karn TS to Commerce Way TS

The 115 kV circuit W8T from Buchanan TS to Edgeware JCT exceeds its planning rating under pre-contingency conditions in the near term based on the gross load forecast. Such thermal overload is deferred to the medium term based on the net load forecast. The transmission line constraint is further described in section 7.2.2 of this report. The remaining 115 kV and 230 kV circuits supplying the London Area are adequate over the study period for the loss of a single element in the area.

6.2 Step-Down Transformation Facilities

There are a total of fifteen step-down transmission connected transformer stations in the London Area Region. The stations have been grouped based on the geographical area and supply configuration. The station loading and the associated station capacity and the need date in each sub-region is provided in Table 6-3 below. The findings of the transformation capacity assessment are as follows:

- As confirmed in the “Strathroy TS Transformer Capacity Local Plan (LP)”, based on the limited time rating (“LTR”) of the station, the transformation capacity is adequate in Strathroy Sub-Region over the study period.
- As confirmed in the “Greater London Sub-Region Integrated Regional Resource Plan (IRRP)”, based on the LTR of the stations, the transformation capacity is adequate in Greater London Sub-Region over the study period.
- Based on the LTR of the load stations, the transformation capacity is adequate in Woodstock Sub-Region, Aylmer-Tillsonburg Sub-Region and the St. Thomas Sub-Region over the study period.

Table 6-2 Transformation Capacities in the Sub-Regions

Sub-Region	Station	LTR (MW)	2015 Non Coincident Peak (MW)	Need Date
Strathroy Sub-Region	Strathroy TS	50	45	-[3]
	Longwood TS	128	33	-[3]
Greater London Sub-Region	Talbot TS	290	268	-[3]
	Clark TS	110	106	-[3]
	Wonderland TS	99	109[4]	-[3]
	Buchanan TS	183	143	-[3]
	Nelson TS	105[5]	23	-[3]
	Highbury TS	114	93	-[3]
Woodstock Sub-Region	Ingersoll TS	167	75	-[3]
	Woodstock TS	87	56	-[3]
	Commerceway TS	112	33	-[3]
Aylmer Sub-Region	Aylmer TS	55[6]	21	-[3]
	Tillsonburg TS	109	88	-[3]
St.Thomas Sub-Region	St.Thomas TS	50	0	-[3]
	Edgeware TS	191	113	-[3]

[3] Adequate over the study period
[4] Peak loading at Wonderland TS is forecasted to reduce to within its 10-day LTR rating by 2017
[5] Nelson TS LTR reflects the Station Rebuild Project under execution - planned to be completed in 2018
[6] Aylmer TS LTR reflects the Transformer Replacement Project under execution - planned to be completed in 2017

The non-coincident and coincident load forecast for all stations in the Region is given in Appendix C and Appendix D, respectively.

6.3 System Reliability and Load Restoration

In case of incidents on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

In the London Area Region it is expected that all loads can be restored within the ORTAC load restoration requirements with exception of:

- Loss of M31W/M32W – Woodstock Sub-Region
- Loss of W36/W37 or W42L/W43L – Greater London Sub-Region

The load restoration constraints are further described in section 7.1 of this report.

6.4 Voltage

Under pre-contingency conditions with all facilities in service, ORTAC provides requirements for acceptable system voltages. The table below indicates the maximum and minimum voltages generally applicable. These values are obtained from Chapter 4 of the IESO "Market Rules" and CSA standards for distribution voltages below 50 kV.

Table 6-3 Pre-Contingency Voltage Limits

Nominal Bus Voltage (kV)	500	230	115	Transformer Station Low Voltage Bus
Maximum Continuous (kV)	550	250	127*	106%
Minimum Continuous (kV)	490	220	113	98%

*Certain buses can be assigned specific maximum and minimum voltages as required for operations. In northern Ontario, the maximum continuous voltage for the 115 kV system can be as high as 132 kV.

With all planned facilities in service pre-contingency, ORTAC provides requirements for system voltage changes in the period immediately following a contingency as indicated in Table 6-4.

Table 6-4 Post-Contingency Voltage Change Limits

Nominal Bus Voltage (kV)	500	230	115	Transformer Station Low Voltage Bus		
				44	27.6	13.8
% voltage change **before** tap changer action	10%	10%	10%	10%		
% voltage change **after** tap changer action	10%	10%	10%	5%		
AND within the range						
Maximum* (kV)	550	250	127	112% of nominal		
Minimum* (kV)	470	207	108	88% of nominal		

*The maximum and minimum voltage ranges are applicable following a contingency. After the system is re-dispatched and generation and power flows are adjusted the system must return to within the maximum and minimum continuous voltages.

The Aylmer-Tillsonburg Sub-Region is normally supplied by a single 115 kV transmission circuit W8T which is approximately 60 km in length. The Sub-Region has a total peak demand of 106 MW and is expected to grow to 122 MW by year 2023. During planned or forced outages the interrupted load in the Sub-Region can be transferred to the backup 115 kV circuit T11T.

Under pre-contingency conditions and with Erie Shores Wind Farm unavailable, the voltage at Tillsonburg TS 115 kV bus does not meet ORTAC criteria (113 kV) under existing peak load conditions and may reach as low as 100 kV. The transformer ULTCs at Tillsonburg TS is however maintaining the LV bus voltage above ORTAC criteria of 27 kV (98% of nominal voltage). Study results indicate that the LV voltage cannot be maintained at desirable levels when the load in the Aylmer-Tillsonburg Sub-Region exceeds 115 MW. Based on the latest load forecasts, this loading level may be reached as early as 2019.

The voltage constraint is further described in section 7.2.1 of this report.

6.5 Customer Delivery Point Performance

In accordance with Section 2.5 of the Transmission System Code, Hydro One Networks Inc. (Networks) is required to develop performance standards at the customer delivery point level, consistent with system wide standards that reflect:

- typical transmission-system configurations that take into account the historical development of the transmission system at the customer delivery point level;
- historical performance at the customer delivery point level;
- acceptable bands of performance at the customer delivery point level for the transmission system configurations; geographic area, load, and capacity levels; and

- defined triggers that would initiate technical and financial evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, exemptions from such standards, and study triggers and results.

The Customer Delivery Point Performance Standards and triggers are based on the size of load being served (as measured in megawatts by a delivery point's total average station load) are provided in Table 6-4 below.

Table 6-4 Customer Delivery Point Performance Standards

Performance Measure	Delivery Point Performance Standards *(Based on a Delivery Point's Total Average Station Load)*							
	0-15 MW		**15-40 MW**		**40-80 MW**		**>80 MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/year)	4.1	**9.0**	1.1	**3.5**	0.5	**1.5**	0.3	**1.0**
DP Interruption Duration (min/year)	89	**360**	22	**140**	11	**55**	5	**25**

The minimum standards of performance are to be used as triggers by Networks to initiate technical and financial evaluations with affected customers. These bands are to:

- accommodate normal year-to-year delivery point performance variations;
- limit the number of delivery points that are to be considered "performance outliers" to a manageable/affordable level;
- deliver a level of reliability that is commensurate with customer value i.e. the larger the load, the greater the level of reliability provided; and
- direct/focus efforts for reliability improvements at the "worst" performing delivery points.

The customer delivery points serving THI and HONI distribution at Tillsonburg TS is not meeting CDPPS requirements with regards to frequency of interruptions. This customer delivery point has averaged approximately 3.3 interruptions per year over the past 10 years, doubling the performance target of 1.5.

The Customer Delivery Point Performance need is further described in section 7.2.3 of this report.

6.6 End-of-Life Equipment Replacements

Recent condition assessment of Wonderland TS has revealed that one of the existing power transformers at the station (T5) is in poor condition and must be replaced in the near-term. The facility was originally built in the 1960s and its assets are degrading in condition and require replacement by 2022. The existing 230/28kV T6 power transformer was replaced in 2004 due to failure. The existing 230/28 kV T5 power transformer will be replaced with a similar unit (230kV-28kV 83 MVA) to match the ratings of transformer T6. After the transformer replacement is completed, the LTR of Wonderland TS is expected to increase to approximately 114MW.

7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES THE ELECTRICAL INFRASTRUCTURE NEEDS, POSSIBLE WIRES ALTERNATIVES AND SUMMARIZES THE CURRENT PREFERRED WIRES SOLUTION FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS IN THE LONDON AREA REGION

The needs listed in Table 7-1 include needs previously identified in the IRRP for the Greater London Sub-Region and the NA and LP's for the Strathroy, Woodstock, Aylmer-Tillsonburg and St. Thomas Sub-Regions.

The near-term needs include needs that arise over the first five years of the study period (2016 to 2020) and the mid-term needs cover the second half of the study period (2021-2025).

Table 7-1 Identified Near-Term Needs in London Region

Sub-Region	Type	Section	Needs	Timing
Woodstock Sub-Region	Load Restoration	7.1.1	Loss of M31W/M32W	No action required at this time
Greater London Sub-Region		7.1.2	Loss of W36/W37 or W42L/W43L	Now
Aylmer-Tillsonburg Sub-Region	Voltage Constraint	7.2.1	Voltage at Tillsonburg TS below ORTAC criteria	Now
	Thermal Constraint	7.2.2	Thermal constraint on 115kV line W8T	Now
	Delivery Point Performance	7.2.3	Poor delivery point performance at Tillsonburg TS	Now

7.1 Load Restoration

7.1.1 Woodstock Sub-Region: Loss of M31W/M32W

Description

The Woodstock Sub-Region load restoration need was identified in the NA and LP reports and further assessment was recommended to address the supply shortfall during peak load periods. Previous assessments indicated that in case of loss of two transmission elements (M31W/M32W), the load interrupted with current circuit configuration during peak periods may exceed load restoration criteria.

Recommended Plan and Current Status

A local planning report[7] was completed to develop a plan to address the load restoration need identified in the Sub-Region. The report concluded the following:

For Woodstock Sub-Region, the critical line section is M31W/M32W tap between Salford Junction and Ingersoll Junction. Should a contingency on this line section occur, all of the sub-region's load, which amounted to 188 MW in 2016, would be interrupted by configuration.

Under such emergency conditions, depending on system performance and availability of switching facilities, all or a portion of a load station could be restored by transferring load to neighbouring unaffected supply. Hydro One Distribution estimated that 10 MW of load at Ingersoll TS could be transferred to Highbury TS. Another 8 MW could be transferred from Commerce Way TS to Tillsonburg TS on the feeder level. On the transmission side, the supply from Brant TS will be able to restore about 20 MW of load in the Woodstock Sub-Region.

These measures can be deployed remotely to manage and mitigate the impact of the loss of two transmission elements within the 4 hours timeframe. To restore the remaining 150 MW of interrupted load within 8 hours, field crews from the nearest staffed centre in London Area will be dispatched to install temporary fixes on the transmission system such as building an emergency by-pass.

The Working Group is recommending that no further action is required at this time.

7.1.2 Greater London Sub-Region: Loss of W36/W37 or W24L/W43L

The Greater London Sub-Region load restoration need was identified in the NA and IRRP reports and further assessment was recommended to address the supply shortfall during peak load periods. Previous assessments indicated that for the loss of two transmission elements (W36/W37 or W42L/W43L), the load interrupted with the current circuit configuration during peak periods may exceed load restoration criteria.

W36/W37 – Clarke TS and Talbot TS

Description

Clarke TS and Talbot TS are supplied by 230 kV transmission circuits W36/W37 and have a total peak demand of 370 MW. Following the loss of both W36 and W37, supply to Clarke TS and Talbot TS would be interrupted.

[7] Woodstock Restoration Local Planning Report – May 30, 2017

Under such emergency conditions, London Hydro can currently restore up to 55 MW of interrupted load through distribution system transfers within 30 minutes and up to 105 MW within four hours. The interrupted load would be transferred to Wonderland TS, Buchanan TS and Highbury TS during such events. As part of the rebuild of Nelson TS in 2018, the station's LV bus will be converted from 13.8 kV to 27.6 kV. After the conversion, Nelson TS will be able to provide additional backup capacity to support meeting the ORTAC timelines in the event of a double circuit outage. With the new 27.6 kV Nelson TS, a total of 95 MW of load can be restored within 30 minutes, and 150 MW of load within four hours. This reduces the 30 minute shortfall to 25 MW and the four hour shortfall to 71 MW in 2019.

Recommended Plan and Current Status

The Greater London Sub-Region IRRP [8] developed a plan to address the load restoration need identified in the Sub-Region. The report concluded the following:

Currently, London Hydro has 28 distribution feeders in total that emanate from Clarke TS and Talbot TS. Only half of these feeders are presently interconnected to other non-Clarke and non-Talbot feeders (i.e., Highbury, Buchanan, and Wonderland TS feeders). Installing approximately 10 additional automated switching devices in strategic locations on the distribution feeders could provide an additional 25 MW of load transfer capability within 30 minutes for Clarke TS and Talbot TS load. These switching devices are estimated to cost approximately $0.6 million.

An additional 10-15 MW of load restoration support for longer-term relief (more than 30 minutes) could be provided by extending the 14 existing Clarke and Talbot feeders to connect with feeders from non-connected neighboring stations. For example, a 3.7 km Talbot feeder line extension to connect to a Wonderland feeder at an approximate cost of $1.2 million could provide support to 10-15 MW of load for the Clarke TS and Talbot TS load pockets.

For a unit cost of $180/kW, the Working Group is recommending the implementation of automated switching devices and feeder extensions on the Distribution System as the most cost effective method to substantially mitigate the restoration shortfall in this area.

These solutions would also maximize the use of existing distribution infrastructure and provide flexibility to London Hydro to manage load between different stations in its service territory.

It is important to note that the feeder capacity margins are not static and will reduce as the 20-year projected load growth at the transformer stations materializes. Hence, the amount of load that can be restored using the distribution system in the event of a double element loss of supply to Clarke TS and Talbot TS will reduce over time. Consequently, part of the recommendation is that London Hydro continues to monitor load growth and relevant feeder limits in its service territory. The Working Group recommends the actions described below to meet the restoration need identified for the Greater London

[8] Greater London Sub-Region, Integrated Regional Resource Plan – January 20, 2017

Sub-region. Successful implementation of this plan will substantially address the restoration need in this sub-region for the next decade.

W42L/W43L – Buchanan TS

In case of loss of theW42L/W43L transmission lines, the load supplied from Buchanan TS which reaches slightly over 150 MW would be interrupted by configuration.

Under such emergency conditions, London Hydro can transfer any interrupted load in excess of 150 MW to adjacent stations within the service area. These measures to manage and mitigate the impact of the equipment loss can be deployed within the 4 hours timeframe. To restore the remaining 150 MW of interrupted load within 8 hours, field crews from the nearest staffed centre in London area will be dispatched to install temporary fixes on the transmission system such as building an emergency by-pass.

The Working Group is recommending that no further action is required at this time.

7.2 Aylmer-Tillsonburg Sub-Region: Voltage/Thermal Constraint & Delivery Point Performance

The Aylmer-Tillsonburg Sub-Region is primarily supplied by a single 115 kV transmission circuit W8T. The Sub-Region has a total peak demand of 106 MW and is expected to grow to 122 MW by year 2023. During planned or forced outages the interrupted load in the Sub-Region can be transferred to the backup 115 kV circuit T11T. The Tillsonburg TS voltage constraint and the W8T thermal constraint need was identified in the NA report and further assessment was recommended to address these needs. Following the NA report, the Working Group further identified Delivery Point Performance needs at Tillsonburg TS. These needs are assessed as part of this RIP.

7.2.1 Voltage Constraint

The voltage constraint observed on the 115 kV bus at Tillsonburg TS results from having a long 65 km 115 kV single circuit supply, a large 90 MW Tillsonburg TS load at the end of the transmission line, and a lack of reactive power support at the station to compensate. To mitigate the voltage constraints at Tillsonburg TS, the Working Group considered the following options.

Installation of Shunt Capacitors at Tillsonburg TS

One method to mitigate the voltage constraints at Tillsonburg TS is to provide reactive power compensation at the station. Installation of shunt capacitor banks (2 x 21 Mvar) on the 27.6 kV bus at Tillsonburg TS provides the necessary reactive compensation to meet the ORTAC voltage criteria (113 kV) for the peak load forecast over the study period of 89 MW at Tillsonburg TS. Further, the shunt capacitors are capable of supporting future load growth beyond the study period up to 109 MW – equal to the LTR rating of Tillsonburg TS. These shunt capacitor banks are estimated to cost approximately $8 million.

Installation of Switching at Buchanan TS and Reconfiguration of 115 kV Circuits

Another method to mitigate the voltage constraints at Tillsonburg TS is to reconfigure the 115 kV circuits supplying the Aylmer-Tillsonburg Sub-Region. A single line diagram of the Aylmer-Tillsonburg Sub-Region after the decommissioning of St. Thomas TS is shown in Figure 7-1.

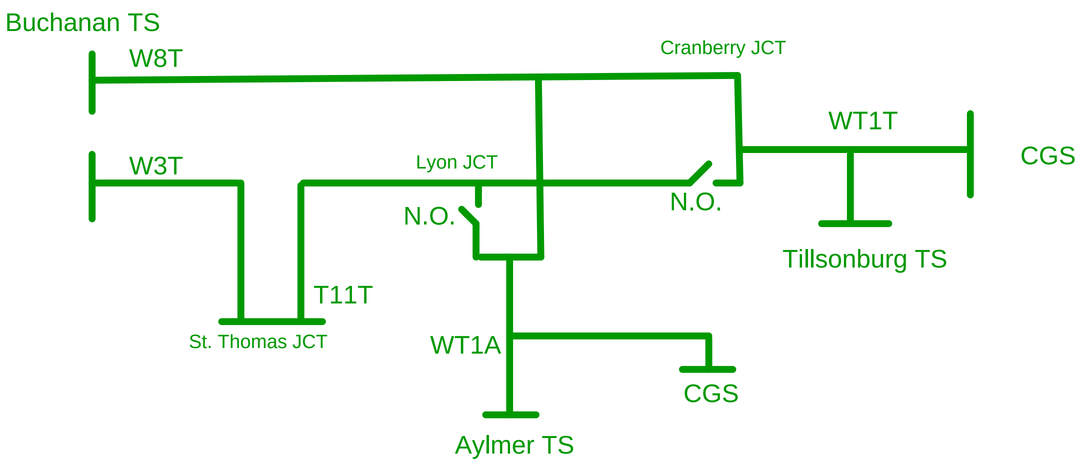

Figure 7-1 Existing Single Line Diagram of Aylmer-Tillsonburg Sub-Region

Aylmer TS and Tillsonburg TS are normally supplied by 115 kV circuit W8T. Reconfiguring the system so that Aylmer TS and Tillsonburg TS are normally supplied by both W8T and T11T reduces the system impedance and improves the voltages in the area. The reconfiguration of the 115 kV system requires installing new switches at Buchanan TS to tie 115 kV circuits W8T and W3T. The "normally open" switches at Lyon JCT and Cranberry JCT will be changed to "normally closed". Lastly the protection relaying at Buchanan TS will require upgrades/modification. A single line diagram of the Aylmer-Tillsonburg Sub-Region after the reconfiguration is shown in Figure 7-2.

The voltages at the Tillsonburg TS 115 kV bus after the reconfiguration improve to 113 kV, meeting the ORTAC voltage criteria for the peak load forecast over the study period. Any further load growth beyond the peak load forecast of 89 MW at Tillsonburg TS will cause the voltage at Tillsonburg TS 115 kV bus to fall below the ORTAC voltage criteria of 113 kV. Similar to the current situation, the transformer ULTCs at Tillsonburg TS can maintain the LV bus voltage above the ORTAC criteria of 27 kV (98% of nominal voltage) for load growth up to 109 MW – equal to the LTR rating of Tillsonburg TS. Reconfiguration of the 115 kV system is estimated to cost approximately $4 million.

While the reconfiguration of the 115 kV system mitigates the voltage constraint need over the study period, it potentially worsens the customer delivery point performance of Tillsonburg Hydro and Hydro One Distribution at Tillsonburg TS. Frequency of outages is expected to increase slightly resulting from higher exposure to lightning and wind events. In addition, restoration times are expected to increase slightly due to the incremental switching requirements.

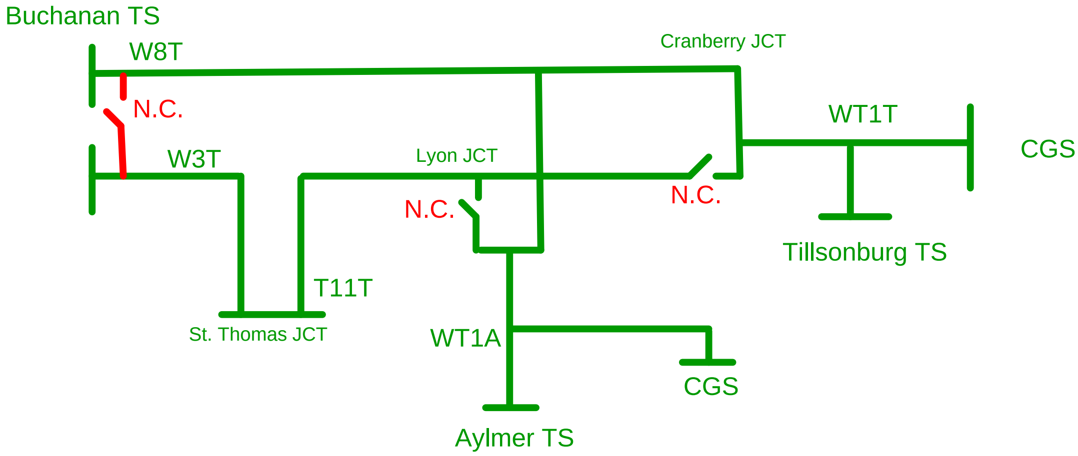

Figure 7-2 Single Line Diagram of Aylmer-Tillsonburg Sub-Region after Reconfiguration

7.2.2 Thermal Constraint

Thermal constraints are observed on a section of line approximately 1.5 km long on 115 kV circuit W8T between Buchanan TS and Edgeware JCT. Under pre-contingency conditions, the thermal loading on this section line reaches 140% of its planning rating of 590A based on the peak load forecast over the study period. Implementing either one of the options in section 7.2.1 to mitigate the voltage constraint at Tillsonburg TS substantially improves the thermal loading on this section line.

Reconfiguring the 115 kV system in the Aylmer-Tillsonburg Sub-Region and installing new switches at Buchanan TS to mitigate the voltage constraint at Tillsonburg TS also mitigates the thermal constraint on circuit W8T.

Installing capacitor banks at Tillsonburg TS reduces the loading on this section of W8T to 106% of its planning rating. As a result, upgrading this section of line would be required to increase the planning to rating to address the thermal overload based on the peak load forecast over the study period. Thirteen poles are required to be replaced at an estimated cost of $1.5 million. This will raise the planning rating of the line to match the other sections of circuit W8T.

A thermal constraint on a section of line approximately 1.5 km long on 115 kV circuit WT1T between Cranberry JCT and Tillsonburg TS was previously identified in the NA report. Tillsonburg Hydro has since provided a revised load forecast and there is no longer an overloading in this section of line.

7.2.3 Customer Delivery Point Performance

The Tillsonburg TS customer delivery point performance need was identified by the Working Group after the NA report was completed. Historical values indicated that the frequency of outages to Tillsonburg Hydro and Hydro One Distribution fall below the standards per Hydro One's "Customer Delivery Point Performance Standard" which is approved by the OEB.

The vast majority of interruptions to Tillsonburg Hydro and Hydro One Distribution at Tillsonburg TS results from having only one normal transmission supply to Tillsonburg TS. One method which substantially improves customer delivery point performance is to provide a second transmission circuit to supply Tillsonburg TS. In most situations, a second supply is normally cost prohibitive. Tillsonburg TS however is in a situation where there is an existing backup 115 kV circuit T11T within 3.5 km of the station. A second transmission supply to Tillsonburg TS would require extending 115kV circuit T11T from Cranberry JCT to Tillsonburg TS, HV bus work at Tillsonburg TS and protection relaying modifications and upgrades at Buchanan TS. Providing a second transmission supply to Tillsonburg TS is estimated to cost approximately $16 million.

7.2.4 Aylmer-Tillsonburg Sub-Region Recommended Plan

The Working Group examined various options to address the voltage, thermal and customer delivery point performance needs of the Sub-Region. The needs, options and alternatives are summarized in Tables 7-2, 7-3 and 7-4 respectively.

Table 7-2 Aylmer-Tillsonburg Sub-Region Needs

Need ID	Needs	Timing
I	Voltage constraint at Tillsonburg TS	Existing
II	Thermal constraint on W8T (Buchannan X Edgeware JCT)	Existing
III	Customer Delivery Point Performance below standards at Tillsonburg TS	Existing

Table 7-3 Aylmer-Tillsonburg Sub-Region Need Mitigation Options

#	Project	Lead Responsibility	I/S Date	Estimated Cost	Mitigated Need ID
1	Installation of Shunt Capacitors at Tillsonburg TS	HONI	2021	$8M	I
2	Installation of Switching at Buchanan TS and Reconfiguration of 115 kV Circuits	HONI	2019	$4M	I & II
3	W8T Circuit Upgrade	HONI	2021	$1.5M	II
4	Second transmission circuit supply to Tillsonburg TS	THI & HONI	2021	$16M	II & III

After further assessing the needs in Aylmer-Tillsonburg Sub-Region, the Working Group proposed a number of different options to mitigate the voltage, thermal and customer delivery point performance needs. Due to the complexity of the projects examined, it was determined that further assessment to clarify scope and specifically the cost details is needed. As such, the Working Group recommends Hydro One to pursue Budgetary Cost Estimates in order to obtain the necessary information to properly analyze the cost and benefits of each alternative.

Hydro One plans to obtain Budgetary Cost Estimates for the alternatives proposed and provide back the results to the Working Group by Q4 2018 in order to continue the planning activities for the Sub-Region.

Table 7-4 Aylmer-Tillsonburg Sub-Region Alternatives

Alternatives	Benefits/	Total Cost
I	Proceed with Projects I, III and IV -Resolves all three needs in the sub-region	$25.5M
II	Proceed with Project II -Resolves need I & II of the sub-region -Increase in the frequency interruptions at Tillsonburg TS -Lengthens restoration time (slightly) during forced outages -During planned or forced outages to W8T or T11T, switches at Buchanan, Lyon JCT and Cranberry JCT will be opened negating the voltage support effects	$4M
III	Proceed with Projects I and III -Resolves needs I & II in the sub-region	$9.5M

7.3 Long Term Regional Plan

As discussed in Section 5, the electricity demand in the London Area Region is expected to remain relatively constant over the study period (approximate growth rate of -0.3%). Load growth over the long term period is expected to be moderate (up to 1.5%) from 2027 to 2037. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

No long term needs for the London Area Region have been identified at this time. If new needs emerge due to a change in load forecast or any other reason, a new regional planning cycle will be initiated ahead of the 5-year planning cycle.

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE LONDON AREA REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in Table 8-1.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

Need ID	Needs	Timing
I	Woodstock Sub-Region load restoration	Now
II	Greater London Sub-Region load restoration	Now
III	Voltage constraint at Tillsonburg TS	Now
IV	Thermal constraint on W8T	Now
V	Poor delivery point performance at Tillsonburg TS	Now
VI	EOL Asset – Wonderland TS transformer T5	2022

Projects, lead responsibility, and timeframes for implementing the wires solutions for the above needs are summarized in Table 8-2 below.

Table 8-2 Regional Plans – Projects, Lead Responsibility, and Planned In-Service Dates

#	Project	Lead Responsibility	I/S Date	Estimated Cost[9]	Mitigated Need ID
1	Distribution System Upgrades in the Greater London Sub-Region	London Hydro Inc.	2023	$1.8-4M ($180/kW)	II
2	Wonderland TS Reinvestment: Replace transformer T5	Hydro One Transmission	2022	$15-20M	VI

Woodstock Sub-Region load restoration need (Need ID I) was assessed by the Working Group during Local Planning and "status quo/do nothing" course of action has been recommended. Further developments in the Region will be monitored and the need will be reviewed again as part of the next planning cycle.

[9] Costs presented are preliminary estimate and may change resulting from clarification of scope and through detailed cost estimating.

Greater London Sub-Region load restoration need (Need ID II) was further assessed during Integrated Regional Resource Planning and the Working Group is recommending the implementation of automated switching devices and feeder extensions on the Distribution System as the most cost effective method to substantially mitigate the restoration shortfall in this area.

Due to the various needs of the Aylmer-Tillsonburg Sub-Region and the complexity of the options proposed, the Working Group is recommending Budgetary Cost Estimates be completed in order to obtain the necessary information to properly analyze the cost and benefits of each alternative.

In accordance with the Regional Planning process, the Regional Planning cycle will be triggered at least once within five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

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APPENDICES

Appendix A: Stations in the London Area Region

Station Name	Voltage Level	Supply Circuits
Strathroy TS	230/27.6kV	W2S, S2N
Talbot TS	230/27.6kV	W36, W37
Clark TS	230/27.6kV	W36, W37
Wonderland TS	230/27.6kV	N21W, N22W
Buchanan TS	230/27.6kV	W42L, W43L
Nelson TS	115/27.6kV[10]	W5N, W6NL
Longwood TS	230/27.6kV	L24L, L26L
Highbury TS	115/27.6kV	W6NL, W9L
Ingersoll TS	230/27.6kV	M31W, M32W
Woodstock TS	115/27.6kV	K7, K12
Commerceway TS	115/27.6kV	K7, K12
Aylmer TS	115/27.6kV	W8T, T11T, WT1A
Tillsonburg TS	115/27.6kV	W8T, T11T, WT1T
St. Thomas TS	115/27.6kV	W3T, W4T, T11T
Edgeware TS	230/27.6kV	W45LS, W44LC

[10] As part of the Nelson TS rebuild planned to be completed by year end 2018, the low voltage bus is being converted from 13.8 kV to 27.6 kV

Appendix B: Non-Coincident Load Forecast 2016-2025

*Gross Load Forecast - Median Weather

Transformer Station Name	LDC/Customer	DESN ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)		
					2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Aylmer TS	Hydro One	*T2/T3*	*18.4*	Gross Peak Load				7	7	7	7	7	7	7	7
	Erie Thames			Gross Peak Load				15	19	19	26	27	27	27	28
				DG				0	0	0	0	0	0	0	0
				CDM				0	1	1	1	2	2	2	2
				Net Load Forecast	21	21	21	21	25	25	32	32	32	33	33
Buchanan TS	Hydro One	*T13/T14*	*183*	Gross Peak Load				10	11	11	11	11	11	11	11
	London Hydro			Gross Peak Load				127	144	146	145	147	148	150	151
				DG				1	1	1	1	1	1	1	1
				CDM				2	4	5	6	8	8	9	10
				Net Load Forecast	147	149	143	134	150	151	149	149	150	151	151
Clark TS	Hydro One	*T3/T4*	*110*	Gross Peak Load				14	14	14	14	14	14	15	15
	London Hydro			Gross Peak Load				95	96	97	98	99	93	94	95
				DG				2	3	3	3	3	3	3	3
				CDM				2	2	3	4	5	6	7	7
				Net Load Forecast	107	111	106	105	106	106	106	106	99	100	101
Commerceway TS	Hydro One	*T1/T2*	*112*	Gross Peak Load				38	34	34	34	34	34	34	34
				DG				0	0	0	0	0	0	0	0
								0	0	0	0	0	0	0	0
				CDM				1	1	1	1	2	2	2	2
				Net Load Forecast	42	33	33	37	33	33	32	32	32	32	32
Edgeware TS	Hydro One	*T1/T2*	*191*	Gross Peak Load				57	57	57	58	59	59	60	60
	London Hydro			Gross Peak Load				1	1	1	1	1	1	1	1
	St. Thomas			Gross Peak Load				52	52	52	52	53	53	53	53
				DG				1	1	1	1	1	1	1	1
				CDM				2	2	3	5	6	7	7	8
				Net Load Forecast	116	97	98	106	106	106	105	105	105	105	105

Transformer Station Name	LDC/Customer	DESN ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)		
					2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Highbury TS	Hydro One	*T3/T4*	*114*	Gross Peak Load				6	7	7	7	7	7	7	7
	London Hydro			Gross Peak Load				88	88	89	83	84	91	92	93
				DG				4	4	4	4	4	4	4	4
				CDM				2	2	3	4	5	6	6	7
				Net Load Forecast	92	93	93	88	88	89	82	82	88	88	89
Ingersoll TS	Hydro One	*T5/T6*	*167*	Gross Peak Load				38	38	38	38	38	38	38	38
	Erie Thames			Gross Peak Load				39	40	40	40	40	40	40	40
				DG				6	6	6	6	6	6	6	6
				CDM				1	2	2	3	4	5	5	6
				Net Load Forecast	76	74	75	70	70	69	68	67	67	67	66
Longwood TS	Hydro One	*T13/T14*	*128*	Gross Peak Load				33	33	34	34	35	36	36	37
				DG				0	0	0	0	0	0	0	0
				CDM				1	1	1	1	2	2	2	3
				Net Load Forecast	39	32	30	32	32	32	33	33	33	34	34
Nelson TS	London Hydro	*T1/T2*	*105*	Gross Peak Load				16	17	15	52	58	59	60	61
				DG				0	0	0	0	15	15	15	15
				CDM				1	1	1	2	2	2	2	2
				Net Load Forecast	45	42	23	16	16	14	50	42	42	43	44
St Thomas TS	St. Thomas	*T3/T4*	*50*	Gross Peak Load				0	0	0	0	0	0	0	0
				DG				0	0	0	0	0	0	0	0
								0	0	0	0	0	0	0	0
				CDM				0	0	0	0	0	0	0	0
				Net Load Forecast	5	1	1	0	0	0	0	0	0	0	0

Transformer Station Name	LDC/Customer	DESN ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)		
					2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Strathroy TS	Hydro One	*T1/T2*	*50*	Gross Peak Load				15	15	15	16	16	16	16	16
	Entegrus			Gross Peak Load				33	34	34	34	35	35	35	36
				DG				1	1	1	1	1	1	1	1
				CDM				1	1	1	2	3	3	3	4
				Net Load Forecast	44	45	45	46	46	47	46	46	47	47	47
Talbot TS	London Hydro	*T1/T2/T3 /T4*	*290*	Gross Peak Load				273	277	282	258	254	256	263	265
				DG				0	0	0	0	0	0	0	0
				CDM				5	7	10	13	14	15	17	18
				Net Load Forecast	242	247	268	268	270	272	245	240	241	246	247
Tillsonburg TS	Hydro One	*T1/T3*	*109*	Gross Peak Load				50	50	51	51	52	53	53	54
	Tillsonburg Hydro			Gross Peak Load				37	38	39	40	41	41	42	42
				DG				0	0	0	0	0	0	0	0
				CDM				2	2	2	4	5	6	6	7
				Net Load Forecast	94	81	88	85	86	87	88	88	89	89	89
Wonderland TS	Hydro One	*T5/T6*	*99*	Gross Peak Load				9	9	9	9	9	9	9	9
	London Hydro			Gross Peak Load				104	90	92	90	92	94	90	92
				DG				1	1	1	1	1	1	1	1
				CDM				2	2	3	4	5	5	6	7
				Net Load Forecast	109	109	109	110	96	97	94	95	97	92	93
Woodstock TS	Hydro One	*T1/T2*	*87*	Gross Peak Load				68	68	68	69	69	69	69	70
				DG				3	3	3	3	3	3	3	3
				CDM				1	1	2	3	4	4	4	5
				Net Load Forecast	62	55	56	64	64	64	63	62	62	62	62

Appendix C: Coincident Load Forecast 2016-2025

Station	Historical MW	Near Term Forecast (MW)					Medium Term Forecast (MW)		
	2015	2016	2017	2018	2019	2020	2021	2022	2023
Aylmer TS	18	18	20	21	22	23	25	27	28
Buchanan TS	126	125	127	129	131	133	135	138	141
Clark TS	96	92	92	91	90	89	88	87	88
Commerceway TS	25	24	23	23	22	21	21	20	20
Edgeware TS	105	103	103	103	102	102	102	102	102
Highbury TS	77	72	72	72	72	71	71	71	71
Ingersoll TS	70	63	63	62	61	60	60	60	59
Longwood TS	31	30	30	31	31	31	31	31	32
Nelson TS	16	16	16	14	50	42	42	43	44
St Thomas TS	0	0	0	0	0	0	0	0	0
Talbot TS	267	261	257	253	249	247	245	242	240
Tillsonburg TS	91	91	92	92	92	92	93	94	95
Wonderland TS	103	98	97	94	92	89	88	85	83
Woodstock TS	58	54	54	54	53	53	53	52	52

Appendix D: List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Hydro One Network Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345.5420
Ajay.Garg@HydroOne.com

Peterborough to Kingston Region

Regional Infrastructure Plan ("RIP")

July 8th, 2016

Kingston Hydro
Hydro One Networks Inc. (Distribution)

The Peterborough to Kingston Region includes Frontenac County, Hasting County, Northumberland County, Peterborough County, and Prince Edward County.

The Needs Assessment ("NA") report for the Peterborough to Kingston region was completed in February, 2015 (see attached). The report concluded that there were only two needs in the region and that they should be addressed as follows:

a) Transformation capacity relief for Gardiner TS T1/T2 DESN1: to be addressed by a Local Plan ("LP").
b) Loading constraints on circuit Q6S: to be addressed by Bulk System Planning and not as part of Regional Planning.

An LP was undertaken by Hydro One Networks Inc. (Transmitter), Hydro One Networks Inc. (Distribution) and Kingston Hydro to address the transformation capacity relief for Gardiner TS T1/T2 DESN1 . The LP recommended re-distributing the load at Gardiner TS by transferring one feeder from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2. The estimated cost of this project is approximately $1.5M. An LP report was prepared and published by the Working Group for the Peterborough to Kingston region in October, 2015 (also attached).

There are no other major development projects planned for the Peterborough to Kingston Region over the near and mid-term

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the ("RIP") for the Sudbury/Algoma Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2014) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: Peterborough to Kingston

Revision: Final
Date: February 10, 2015

Prepared by: Peterborough to Kingston Region Study Team

Peterborough to Kingston Region Study Team	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Quyen Diep Sachna Bobal
Independent Electricity System Operator	Phillip Woo Jiya Shoaib
Veridian Connections Inc.	Craig Smith
Kingston Hydro	Thomas Brackenbury
Peterborough Distribution Inc.	Jeff Guilbeault
Hydro One Networks Inc. (Distribution)	Ashley LeBel

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Peterborough to Kingston Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Peterborough to Kingston Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	December 12, 2014	**END DATE**	Feb 10, 2015

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Peterborough to Kingston Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the Peterborough to Kingston Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Peterborough to Kingston Region belongs to Group 2. The NA for this Region was triggered on December 12, 2014 and was completed on Feb 10, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to the next 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2023.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning.

This NA included a study of transmission system connection facilities capability, which covers station and line loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Peterborough to Kingston Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life. See Section 4 for further details.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2014 to 2023). The assessment reviewed available information and load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Capacity Needs

A. 230/115 kV Autotransformers

- The 230/115 kV autotransformers (Dobbin TS and Cataraqui TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.
- Under high Transfer East of Cherrywood and low water conditions in the east, P15C may be loaded near its continuous rating under pre-contingency conditions. This issue will be further assessed by the IESO as part of bulk system planning.

C. 115kV Transmission Lines

- With the loss of 230 kV circuit P15C, the 115 kV circuit Q6S may reach its LTE ratings in the near term based on the gross load forecast. The net load in the area is forecasted to decrease from 2014-2023 with the inclusion of DG and CDM. No action is required at this time and the capacity need will be reviewed in the next planning cycle.
- The remaining 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region.
- With the loss of 230 kV circuits P15C and C27P and expected load additional loading in Renfrew area in 2018, the circuit Q6S may be loaded beyond its LTE rating. This issue will be further assessed by the IESO as part of bulk system planning.

D. 230 kV and 115 kV Connection Facilities

- Gardiner TS T1/T2 DESN1 (summer peaking station) is forecasted to exceed its normal supply capacity from 2014 to 2023 based on the gross load forecast (approximately 112% and 117% of Summer 10-Day LTR in 2014 and 2023 respectively). However, based on the net load forecast with planned CDM targets and DG contributions, the station capacity for Gardiner TS T1/T2 DESN1 is adequate to meet the net forecasted load over the study period. It should be noted that Gardiner TS T3/T4 DESN2 is lightly loaded. Hydro One transmission will undertake an assessment of the need for load transfers as a local planning initiative and work with LDCs to develop a plan to balance load between the two DESNs

System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for this Region. Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

For the loss of two elements, the load interrupted by configuration may exceed 150 MW based on the gross coincident load forecast. However, based on the net coincident load forecast, the load interrupted by configuration does not exceed 150 MW. No action is required at this time.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace major equipment do not affect the needs identified.

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that

- "localized" wires only solutions be developed in the near-term to adequately and efficiently address the needs associated with transformation capacity relief for Gardiner TS T1/T2 DESN1 as indicated above through planning between Hydro One Networks Inc. and the impacted distributors. See Section 7 for further details, and
- IESO to assess loading constraints on circuit Q6S for the loss of two elements, and P15C under high transfers as part of their bulk system planning

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1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Peterborough to Kingston Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the Peterborough to Kingston Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by the Peterborough to Kingston Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the IESO.

Table 1: Study Team Participants for Peterborough to Kingston Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
3.	Independent Electricity System Operator ("IESO")
4.	Kingston Hydro Corporation ("Kingston Hydro")
5.	Peterborough Distribution Inc. ("Peterborough Distribution")
6.	Veridian Connections Inc. ("Veridian")
7.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the Peterborough to Kingston Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Peterborough to Kingston Region belongs to Group 2. The NA for this Region was triggered on December 12, 2014 and was completed on Feb 10, 2015.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the Peterborough to Kingston Region over an assessment period of 2014 to 2023. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station and line thermal capacity and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 Peterborough to Kingston Region Description and Connection Configuration

The Peterborough to Kingston Region includes Frontenac County, Hasting County, Northumberland County, Peterborough County, and Prince Edward County. The boundaries of the Peterborough to Kingston Region are shown below in Figure 1.

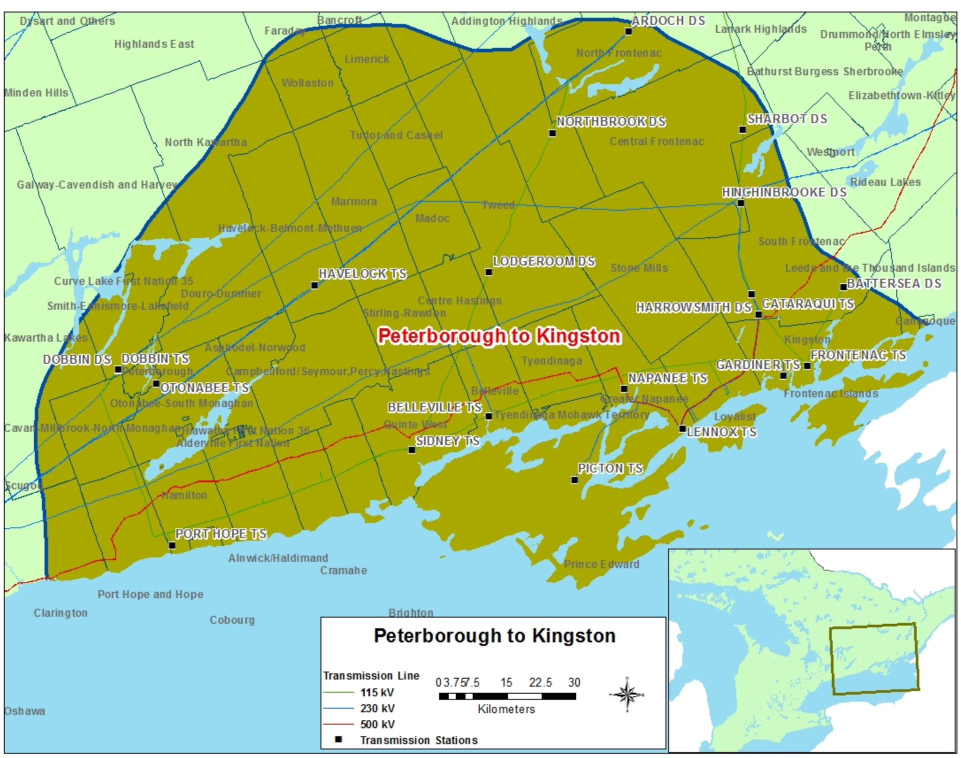

Figure 1: Peterborough to Kingston Region Map

Electrical supply to the Peterborough to Kingston Region is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Lennox Transformer Station (TS) and 230/115 kV autotransformers at Cataraqui TS and Dobbin TS. There are ten Hydro One step-down TS's, eight high voltage distribution stations (HVDS), and five other direct transmission connected load customers in the Region. The distribution system consists of voltage levels 44 kV, 27.6 kV, 12.5 kV, 8.32kV, and 4.16kV. The main generation facility in the Region is the 2000 MW Lennox Generation Station (GS) connected to Lennox TS.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment:

- Lennox TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.

- Cataraqui TS and Dobbin TS are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.

- Ten step-down transformer stations supply the Peterborough to Kingston load: Dobbin TS, Port Hope TS, Sidney TS, Picton TS, Otonabee TS, Havelock TS, Belleville TS, Napanee TS, Gardiner TS, and Frontenac TS. There are also eight HVDS that supply load in the Region: Dobbin DS, Ardoch DS, Northbrook DS, Lodgeroom DS, Hinchinbrooke DS, Harrowsmith DS, Sharbot DS, and Battersea DS.

- Five Customer Transformer Stations (CTS) are supplied in the Region: TransCanada Pipelines Cobourg CTS, TransCanada Pipelines Belleville CTS, Enbridge Pipelines Hilton CTS, Lafarge Canada Bath CTS, and Novelis CTS.

- There are 3 existing Transmission connected generating stations in the Region as follows:
  - Lennox GS is a 2000 MW natural gas-fired station connected to Lennox TS
  - NPIF Kingston GS is a 130 MW gas-fired cogeneration facility that connects to 230 kV circuits X1H and X2H near Lennox TS
  - Wolfe Island GS is a 198 MW wind farm connected to circuit X4H near Gardiner TS

- A 910 MW gas-fired plant (Napanee GS) is expected to connect to Lennox TS at the 500kV level in 2018.

- Up to 535 MW of additional transmission connected renewable generation could be in service in the Region by the year 2023.

- There are a network of 230 kV and 115 kV circuits that provide supply to the Region, as shown in Table 2 below:

Table 2: Transmission Lines in Peterborough to Kingston Region

Voltage	Circuit Designations	Location
230 kV	X1H, X2H, X3H, X4H	Hinchinbrooke SS to Lennox TS
	X21, X22	Picton TS to Lennox TS
	H23B	Belleville TS to Hinchinbrooke SS
	H27H	Hinchinbrooke SS to Havelock TS
	X1P	Dobbin TS to Chenaux TS
	C27P	Dobbin TS to Chat Falls GS
	H24C, H26C	Cherrywood TS to Havelock TS
	C28C	Cherrywood TS to Chat Falls GS
	P15C	Cherrywood TS to Dobbin TS
	B23C	Cherrywood TS to Belleville TS
115 kV	P3S, P4S	Dobbin TS to Sidney TS
	Q6S	Cataraqui TS to Sidney TS
	B1S	Barrett Chute TS to Sidney TS
	Q3K	Cataraqui TS to Frontenac TS
	B5QK	Cataraqui TS to Frontenac TS to Barrett Chute TS

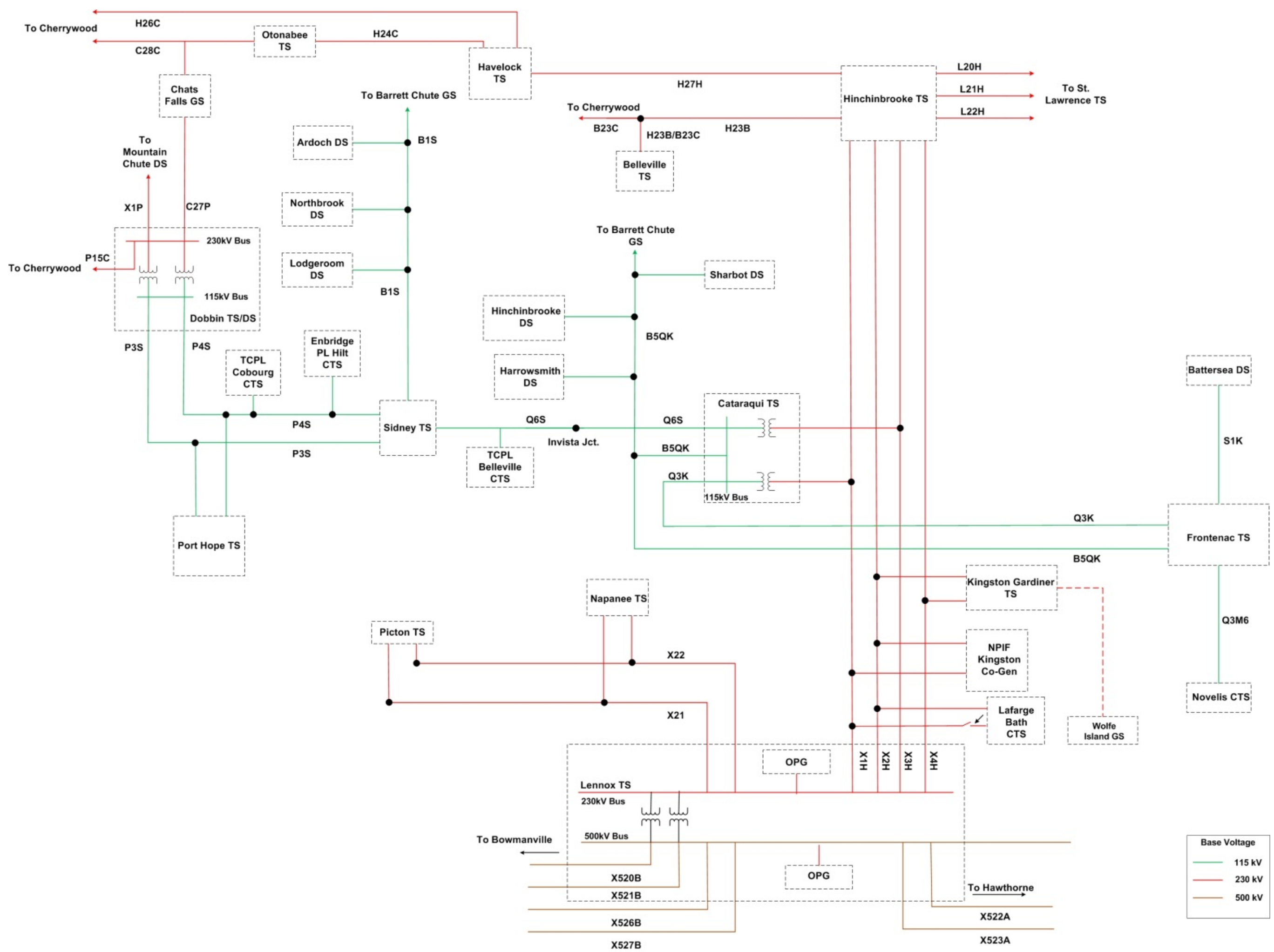

Figure 2: Single Line Diagram – Peterborough to Kingston Region

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- IESO provided:
    i. Historical 2013 regional coincident peak load and station non-coincident peak load
    ii. List of existing reliability and operational issues
    iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2011-2013) net load, and gross load forecast (2014-2023)
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Gross Load Forecast

As per the data provided by the study team, the gross load in the Peterborough to Kingston Region is expected to grow at an average rate of approximately 0.4% annually from 2014-2023.

4.2 Net Load Forecast

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. The net load is expected to decrease at an average rate of approximately 0.6% annually from 2014-2023.

5 NEEDS ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

1. The Region consists of both winter and summer peaking stations. Therefore, this assessment is based on both winter and summer peak loads, as appropriate.

2. Forecast loads are provided by the Region's LDCs. LaFarge Canada had provided a load forecast for LaFarge Canada CTS. Load data was not received by the other industrial customers in the region (Enbridge Pipeline Inc, TransCanada Pipeline Ltd.). For these stations, the load was assumed to be consistent with historical loads.

3. The LDC's load forecast is translated into load growth rates and is applied onto the 2013 summer/winter peak load as a reference point.

4. The 2013 summer/winter peak loads are adjusted for extreme weather conditions according to Hydro One's methodology.

5. Accounting for (2), (3), (4) above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG is analyzed to determine if needs can be deferred.

   A coincident version of the gross and net load forecast was used to assess the transformer capacity needs (section 6.1.1), 230 kV transmission line needs (section 6.1.2), 115 kV transmission line needs (6.1.3) and system reliability operation and restoration needs (6.2).

   A non-coincident version of the gross and net load forecast was used to assess the station capacity as presented in section 6.1.4.

   A coincident peak load forecast and a non-coincident peak load forecast were produced for each gross load and net load forecasts.

6. Review impact of any on-going and/or planned development projects in the Region during the study period.

7. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.

8. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer or winter 10-Day Limited Time Rating (LTR), as appropriate.

9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer or winter 10-Day LTR, as appropriate.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) (Section 4.2) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC (Section 7.2) criteria.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Peterborough to Kingston Region.

6.1 Transmission Capacity Needs

6.1.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Dobbin TS and Cataraqui TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

6.1.2 230 kV Transmission Lines

The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

Under high Transfer East of Cherrywood and low water conditions in Eastern Ontario, the 230 kV circuit P15C may be loaded near its continuous rating under pre-contingency conditions. This issue should be further assessed by the IESO as part of bulk system planning.

6.1.3 115kV Transmission Lines

With the loss of 230 kV circuit P15C, the 115 kV circuit Q6S from Invista Jct to Sidney TS may reach its LTE rating in the near term based on the gross load forecast. The net load forecast in the area is forecasted to decrease from 2014-2023 with the inclusion of DG and CDM. No action is required at this time and the capacity need will be reviewed in the next planning cycle.

With the loss of 230 kV circuits P15C and C27P and expected additional loading in the Renfrew region in 2018, the circuit Q6S may be loaded beyond its LTE rating. This issue should be further assessed by the IESO as part of bulk system planning.

The remaining 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region.

6.1.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV TSs and HVDSs in the Region using either the summer or winter station peak load forecasts as appropriate that were provided by the study team. The results are as follows:

Gardiner TS

Gardiner TS T1/T2 DESN1 (summer peaking station) is forecasted to exceed its normal supply capacity from 2014 to 2023 based on the gross load forecast (approximately 112% and 117% of Summer 10-Day LTR in 2014 and 2023 respectively). However, based on the planned CDM targets and DG contributions, the station capacity for Gardiner TS T1/T2 DESN1 is adequate to meet the net forecasted demand over the study period.

It should be noted that Gardiner TS T3/T4 DESN2 is lightly loaded. Hydro One transmission will undertake an assessment of the need for load transfers as a local planning initiative and work with LDCs to develop a plan to balance load between the two DESNs

All the other TSs and HVDSs in the Region are forecasted to remain within their normal supply capacity during the study period. Therefore, no action is required at this time and the capacity needs will be reviewed in the next planning cycle.

6.2 System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for this Region.

Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

For the loss of circuits X2H and X4H, the load interrupted by configuration at Gardiner TS may exceed 150 MW based on the gross coincident load forecast. However, based on the net coincident load forecast, which accounts for CDM and DG, the load interrupted by configuration does not exceed 150 MW. Therefore, no action is required at this time and this will be reviewed in the next planning cycle.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables.

During the study period:

- Replacement (like-for-like) of both transformers (T1 and T2) at Gardiner TS DESN1 is scheduled in 2020. The replacement plan does not affect the results of this NA study.

- Replacement of two autotransformers, T2 and T5 (78 MVA and 115 MVA respectively), at Dobbin TS with a single 150/250 MVA autotransformer is scheduled in 2019. The third autotransformer (T1) will remain the same. The replacement plan does not affect the results of this NA study.

- There are no significant lines sustainment plans that will affect the results of this NA study.

7 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, the study team recommends that no further coordinated regional planning is required.

Rather the study team recommends the following to address the identified needs:

a) Hydro One transmission will lead the assessment and develop a local plan ("Gardiner TS Load Balancing") with the relevant LDCs to balance load between the two DESNs at Gardiner TS; and,
b) IESO to assess and develop a plan for the contingencies associated with circuit Q6S for the loss of two elements and loading constraints on circuit P15C under high transfers within the context of a bulk planning study for the area.

8 NEXT STEPS

Hydro One Transmission and impacted LDCs will address the recommendation in Section 7a and develop a local plan.

IESO to initiate a bulk planning study for the area.

9 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: March 2014 – August 2015
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

10 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
IESO	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

GARDINER TS LOAD BALANCING

Region: Peterborough to Kingston

Revision: FINAL
Date: October 7, 2015

Prepared by: "Peterborough to Kingston" Region Local Planning Study Team

Peterborough to Kingston Region Local Planning Study Team
Organization
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Kingston Hydro (Embedded LDC)

DISCLAIMER

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Peterborough to Kingston Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Local Planning Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Peterborough to Kingston (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	April 10, 2015	**END DATE**	October 7, 2015

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only options and recommend a preferred solution that will address the local needs identified in the Needs Assessment (NA) report for the Peterborough to Kingston Region. The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

2. LOCAL NEED ADDRESSED IN THIS REPORT

The Needs Assessment (NA) report for the Peterborough to Kingston Region indicated that Gardiner TS T1/T2 DESN1 is forecasted to exceed its normal supply capacity in the near term. Gardiner TS T3/T4 DESN2 is lightly loaded. The local need addressed in this report will be how to best alleviate the station capacity issue at Gardiner TS T1/T2 DESN1.

3. ALTERNATIVES CONSIDERED

The alternatives considered were:

1) Transfer load from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN
2) Do Nothing

4. PREFERRED ALTERNATIVE

Transferring load from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2 is the preferred alternative as it addresses the station capacity issue at Gardiner TS T1/T2 DESN1. Transferring some of the existing load at Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2 is the most straight forward and cost effective option.

5. RECOMMENDATIONS

Hydro One Distribution will proceed with a detailed estimate for the load transfer work at Gardiner TS. The detailed estimate for the load transfer work is expected to be completed mid-2016. The expected in-service date for this work is end of 2018.

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1 Introduction

The Needs Assessment (NA) for the Peterborough to Kingston Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 Regions is complete and will be initiated for Group 3 Regions later this year. The Peterborough to Kingston Region belongs to Group 2. The NA for this Region was triggered on December 12, 2014 and was completed on Feb 10, 2015. The NA for the Peterborough to Kingston Region was prepared jointly by the study team, including Local Distribution Companies (LDC), Independent Electric System Operator (IESO), Ontario Power Authority (merged with IESO as of January 2015 and herein referred to as IESO), and Hydro One. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Peterborough to Kingston Region over the next ten years (2014 to 2023) and recommended whether they should be further assessed through the transmitter-led Local Planning (LP) process or the IESO-led Scoping Assessment (SA) process.

This report was prepared by the Peterborough to Kingston Region LP study team (Table 1) and led by the transmitter, Hydro One Networks Inc. (Hydro One). The report captures the results of the assessment based on information provided by LDCs and Hydro One.

Table 1: Study Team Participants for Peterborough to Kingston Region

Organization
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Kingston Hydro (Embedded LDC)

2 Regional Description

The Peterborough to Kingston Region includes Frontenac County, Hasting County, Northumberland County, Peterborough County, and Prince Edward County. Please refer to the NA Report for further details. The Peterborough to Kingston Region and its approximate boundaries are shown in Figure 1. The facilities in the Region are depicted in the single line diagram shown in Figure 2.

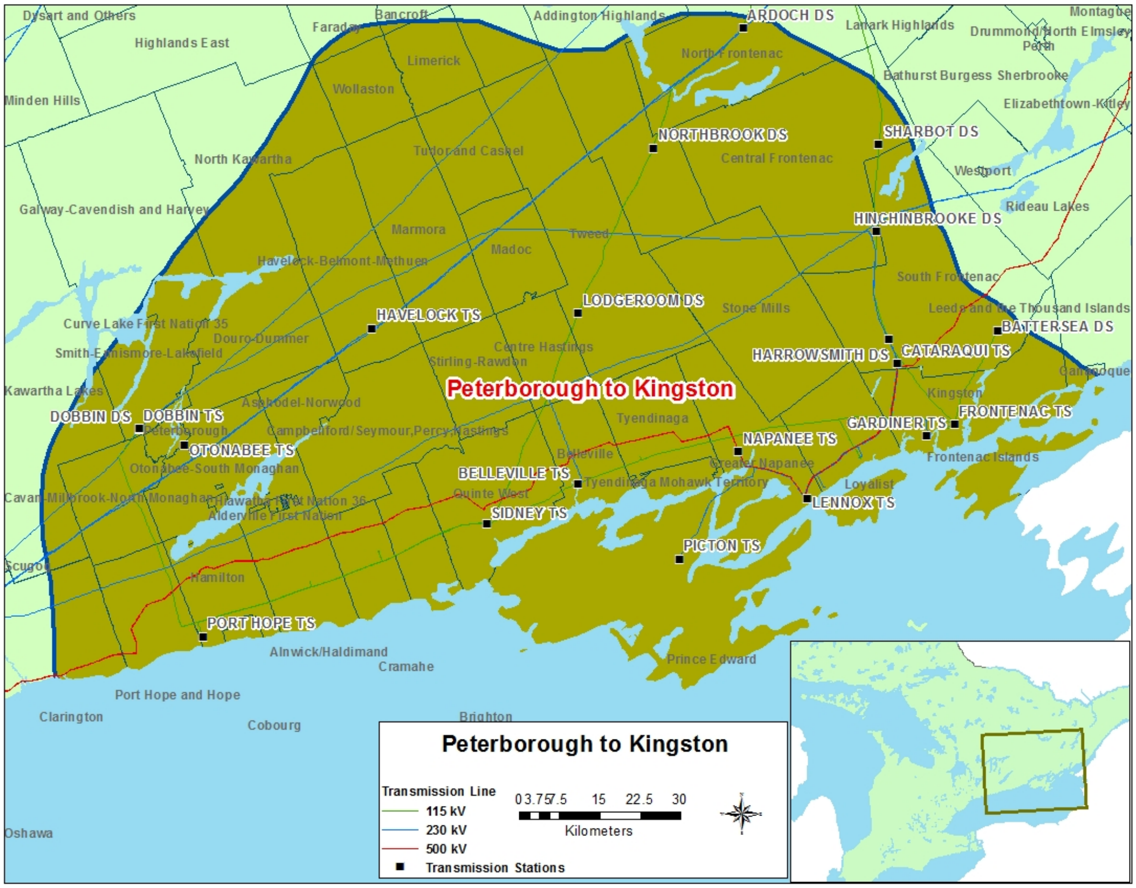

Figure 1: Peterborough to Kingston Region Map

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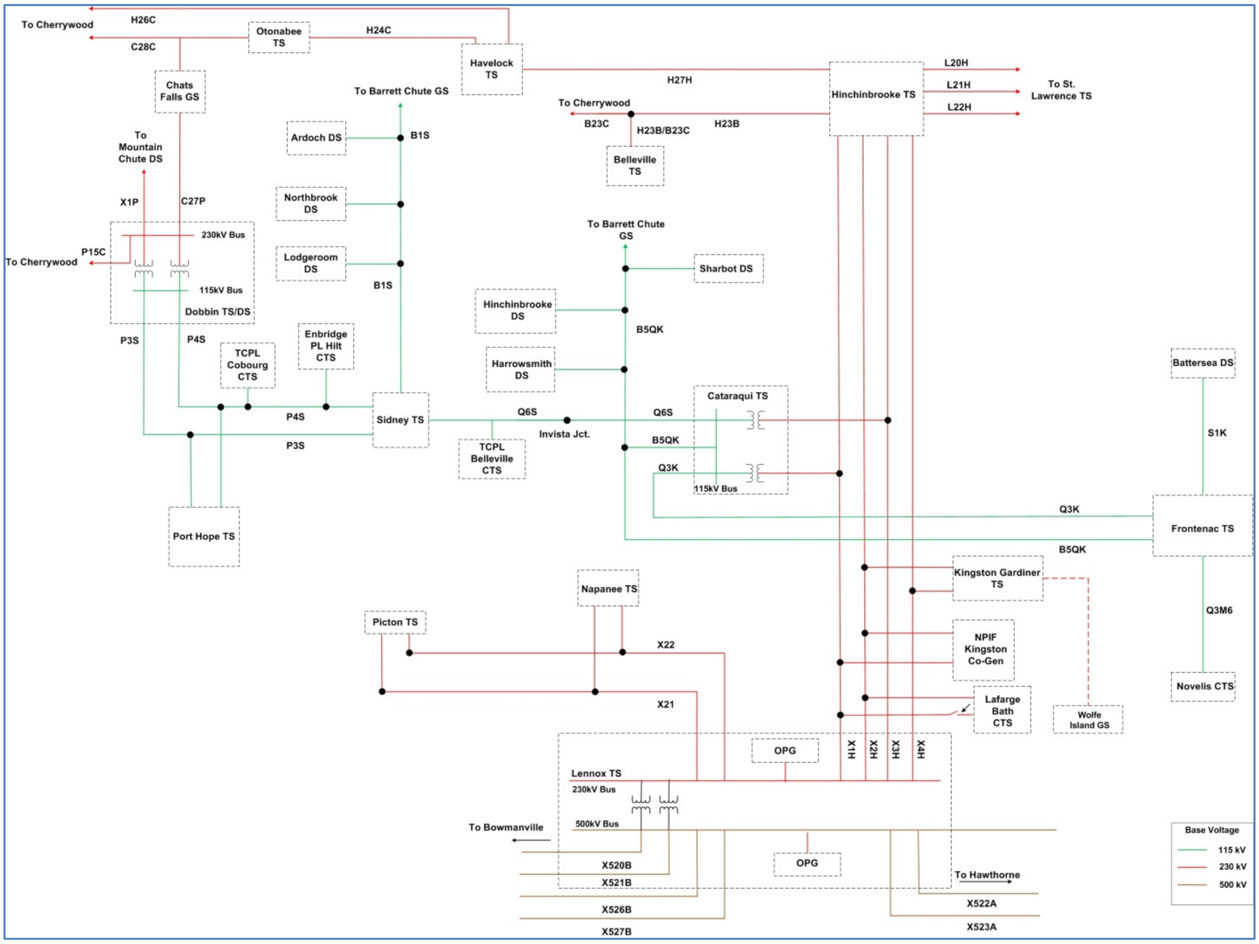

Figure 2: **Single Line Diagram – Peterborough to Kingston Region**

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3 Peterborough to Kingston Region Needs

As an outcome of the NA process, the study team identified a need to address the normal supply capacity at Gardiner TS T1/T2 DESN1. Since this need can be clearly addressed by a straightforward wires solution, the study team agreed that it should be further planned directly by the impacted LDC and the transmitter through the LP process and that further coordinated regional planning was not required. Hydro One with the impacted LDCs further undertook planning assessments to develop options and recommend a wires only solution(s). Gardiner TS (230/44 kV)

3.1 Gardiner TS (230/44kV)

Gardiner TS T1/T2 DESN1 is forecasted to exceed its normal supply capacity from 2014 to 2023 based on the gross load forecast (approximately 112% and 117% of Summer 10-Day LTR in 2014 and 2023 respectively). However, based on the net load forecast which takes planned CDM targets and DG contributions into consideration, this issue will be avoided. Nevertheless, the station will still be loaded at 100% of its thermal capacity at that time. The load forecast provided by LDCs and the CDM and DG forecast provided by the IESO are attached in Appendix A.

4 Options Considered

This section describes the options considered to address the local need described in section 3.1.

4.1 Gardiner TS Load Balancing

Prior to the regional planning process, Hydro One Distribution had already planned on re-distributing the load at Gardiner TS by transferring one feeder from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2. This would alleviate the loading concerns at Gardiner TS T1/T2 DESN1 for this study period. The preliminary budgetary cost estimate for this project is about $1.5M.

4.2 Do Nothing

Do nothing is not a viable option since it could result in the violation of transformer ratings at Gardiner TS T1/T2 DESN1, which is not acceptable.

5 Recommendation

The study team agreed that transferring one feeder from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2 would relieve the thermal loading at Gardiner TS T1/T2 DESN1. This is a cost effective solution that will ensure that any additional load growth during the study period at Gardiner TS can be accommodated without exceeding the station thermal limit. Hydro One Distribution will be proceeding with the development of a plan to transfer the load along with a cost estimate for the work by the end of 2015. The expected in-service date for this feeder load transfer is end of 2018.

6 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
iii) Peterborough to Kingston Region Needs Assessment Report

Appendix A: Load Forecast for Peterborough to Kingston Region

Table A1: Gross Load Forecast (MW)

Transformer Station	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Ardoch DS T1	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2
Battersea DS T1/T2	9.4	9.4	9.4	9.4	9.3	9.2	9.1	9.1	9.0	9.0
Belleville TS T1/T2	141.5	131.7	131.4	131.1	130.8	129.8	128.7	128.6	128.3	128.0
Dobbin DS T1	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Dobbin DS T2	6.3	6.2	6.2	6.2	6.2	6.2	6.1	6.1	6.1	6.1
Dobbin TS T3/T4	83.5	83.2	83.0	83.0	82.7	81.6	80.5	80.3	79.9	79.5
Frontenac TS T3/T4	100.8	101.5	102.3	103.3	104.0	103.8	103.6	104.4	105.0	105.5
Gardiner TS T1/T2	125.3	124.9	124.8	125.2	124.8	122.9	121.2	120.9	120.4	119.8
Gardiner TS T3/T4	15.8	15.8	15.9	15.9	16.0	15.8	15.7	15.7	15.7	15.7
Harrowsmith DS T1	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.3	9.4
Harrowsmith DS T2	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.3	9.4
Havelock TS T1/T2	63.5	63.3	63.2	63.2	63.1	62.4	61.8	61.7	61.5	61.3
Hinchinbrooke DS T1	6.5	6.5	6.5	6.5	6.5	6.4	6.4	6.3	6.3	6.3
Lodgeroom DS T1	5.1	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3	5.3
Lodgeroom DS T2	5.0	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1	5.1
Napanee TS T1/T2	55.1	52.6	52.5	53.1	53.3	53.0	52.7	53.1	53.4	53.6
Northbrook DS T1	6.8	6.8	6.8	6.8	6.8	6.8	6.7	6.7	6.7	6.6
Otonabee TS T1/T2	43.6	43.4	43.1	43.1	42.9	42.4	41.9	41.7	41.5	41.3
Otonabee TS T1/T2	84.3	83.8	83.4	83.4	83.0	81.8	80.8	80.5	80.0	79.6
Picton TS T1/T2	54.6	46.4	46.6	47.0	47.2	46.8	46.4	46.7	46.8	46.9
Port Hope TS T1/T2	53.1	49.7	49.3	49.4	49.4	48.9	48.5	48.5	48.4	48.3
Port Hope TS T3/T4	64.1	63.4	63.2	63.2	63.0	62.1	61.3	61.1	60.9	60.6
Sharbot DS T1	4.3	4.3	4.3	4.3	4.3	4.3	4.2	4.2	4.2	4.2
Sidney TS T1/T2	64.1	63.9	63.8	64.0	63.9	63.1	62.4	62.4	62.2	62.1
LaFarge Canada CTS	21.0	21.0	21.0	22.0	17.0	17.0	17.0	17.0	17.0	17.0
Enbridge PL Hilt CTS	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
TCPL Cobourg CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
TCPL Belleville CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

Table A2: Net Load Forecast (MW)

Transformer Station	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Ardoch DS T1	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Battersea DS T1/T2	10.0	10.0	10.1	10.1	10.1	10.1	10.2	10.2	10.2	10.2
Belleville TS T1/T2	148.9	149.3	149.6	149.9	150.3	150.6	150.9	151.3	151.6	152.0
Dobbin DS T1	5.6	5.7	5.8	5.8	5.9	5.9	6.0	6.1	6.1	6.2
Dobbin DS T2	6.3	6.3	6.4	6.4	6.4	6.5	6.5	6.6	6.6	6.6
Dobbin TS T3/T4	84.3	84.6	84.9	85.3	85.6	85.9	86.2	86.5	86.8	87.1
Frontenac TS T3/T4	106.2	107.6	108.9	110.3	111.7	113.0	114.4	115.8	117.2	118.5
Gardiner TS T1/T2	140.5	141.3	142.2	143.1	143.7	144.3	144.9	145.5	146.1	146.7
Gardiner TS T3/T4	16.0	16.1	16.2	16.4	16.5	16.6	16.8	16.9	17.1	17.2
Harrowsmith DS T1	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.4	9.4
Harrowsmith DS T2	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.4	9.4
Havelock TS T1/T2	64.0	64.2	64.4	64.6	64.9	65.1	65.3	65.5	65.7	66.0
Hinchinbrooke DS T1	6.6	6.6	6.6	6.7	6.7	6.7	6.7	6.7	6.8	6.8
Lodgeroom DS T1	5.1	5.2	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.4
Lodgeroom DS T2	5.1	5.1	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3
Napanee TS T1/T2	71.1	72.0	72.8	73.6	74.4	75.2	76.0	76.9	77.7	78.5
Northbrook DS T1	6.9	6.9	7.0	7.0	7.0	7.0	7.1	7.1	7.1	7.2
Otonabee TS T1/T2	45.5	45.6	45.7	45.8	45.9	46.0	46.1	46.1	46.2	46.3
Otonabee TS T1/T2	88.0	88.2	88.3	88.5	88.6	88.8	88.9	89.0	89.2	89.3
Picton TS T1/T2	55.1	55.7	56.3	56.9	57.5	58.2	58.8	59.4	60.0	60.6
Port Hope TS T1/T2	53.7	54.0	54.3	54.5	54.8	55.1	55.4	55.7	56.0	56.3
Port Hope TS T3/T4	64.7	65.0	65.3	65.5	65.8	66.1	66.4	66.6	66.9	67.2
Sharbot DS T1	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5
Sidney TS T1/T2	77.3	77.7	78.0	78.3	78.7	79.0	79.3	79.7	80.0	80.3
LaFarge Canada CTS	21.0	21.0	21.0	22.0	17.0	17.0	17.0	17.0	17.0	17.0
Enbridge PL Hilt CTS	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
TCPL Cobourg CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
TCPL Belleville CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

Table A3: Conservation Demand Management (Percent of Gross Load)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
C&S	0.0%	0.2%	0.5%	0.6%	1.1%	1.6%	1.9%	2.3%	2.5%	2.6%
TOU	0.2%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
EE programs	0.5%	0.8%	1.0%	1.1%	1.3%	2.1%	3.1%	3.2%	3.6%	4.2%
Total	1%	1%	2%	2%	3%	4%	5%	6%	6%	7%

Table A4: Distributed Generation (MW)

Transformer Station	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Ardoch DS T1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Battersea DS T1/T2	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Belleville TS T1/T2	6.7	16.2	16.2	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Dobbin DS T1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Dobbin DS T2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Frontenac TS T3/T4	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Gardiner TS T1/T2	13.8	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2
Lodgeroom DS T1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lodgeroom DS T2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Napanee TS T1/T2	15.5	18.3	18.7	18.7	18.9	18.9	18.9	18.9	18.9	18.9
Otonabee TS T1/T2	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Otonabee TS T1/T2	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Picton TS T1/T2	0.0	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Port Hope TS T1/T2	0.2	3.5	3.9	3.7	4.0	4.0	4.0	4.0	4.0	4.0
Port Hope TS T3/T4	0.0	0.46	0.52	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Sidney TS T1/T2	12.7	12.	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7

South Georgian Bay/Muskoka

REGIONAL INFRASTRUCTURE PLAN

August 18th, 2017

hydro one

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Independent Electricity System Operator
Alectra Utilities Corporation (formerly PowerStream Inc.)
Hydro One Networks Inc. (Distribution)
InnPower Corporation
Orangeville Hydro Ltd.
Veridian Connections Inc.

DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address near and mid-term needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Study Team.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Study Team.

Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") AND THE STUDY TEAM IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS OF THE SOUTH GEORGIAN BAY/MUSKOKA REGION.

The participants of the RIP Study Team included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator
- Alectra Utilities (formerly PowerStream Inc.)
- Hydro One Networks Inc. (Distribution)
- InnPower Corporation
- Orangeville Hydro Ltd.
- Veridian Connections Inc.

This RIP is the final phase of the OEB's mandated regional planning process for the South Georgian Bay/Muskoka Region. It follows the completion of Integrated Regional Resource Plans ("IRRP") for Barrie/Innisfil and Parry Sound/Muskoka Sub-Regions on December 16, 2016.

This RIP provides a consolidated summary of the needs and recommended plans for the South Georgian Bay/Muskoka Region which includes the Barrie/Innisfil and Muskoka/Parry Sound Sub-Regions. The major transmission and distribution infrastructure investments planned for the South Georgian Bay/Muskoka Region over the near and mid-term, as identified in the various phases of the regional planning process are given in the Table below.

No.	Project	I/S Date	Cost ($ Million)
1	Replacement of 115-44kV transformers (T1 and T2) at Barrie TS, uprating 115kV circuits to 230kV, adding additional feeders to Barrie DESN	2020/2021	$84
2	Replacement of 230-44kV transformers (T1 and T2) and possible rebuild of low voltage switchyard at Minden TS	2020/2021	$17
3	Installation of sectionalizing motorized disconnect switches on circuits M6E/M7E (at Orillia TS)	2021	$5-7
4	Build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS*	2020	$7
5	Replacement of 230/44 kV transformers at Parry Sound TS*	2021	$20
6	Replacement of dual windings 230-44/27.6kV transformers (T1 and T2) and associated low voltage equipment at Orangeville TS	2024/2025	$33

* Replacement of transformers at Parry Sound TS would eliminate the need to build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS

A load transfer from Barrie TS to Midhurst TS that is planned for 2019 will address the near-term capacity need at Barrie TS and will defer the capacity need of the upgraded Barrie TS to 2031.

A cost-benefit/responsibility analysis will be considered by Hydro One Distribution, Lakeland Power and Veridian Connections to improve reliability performance of the Parry Sound/Muskoka 44 kV sub-transmission system, which will be completed by the end of 2017.

As per the Regional Planning process, the Regional Plan will be reviewed and/or updated at least once every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can also be started earlier.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE SOUTH GEORGIAN BAY/MUSKOKA REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Hydro One Distribution, Alectra Utilities (formerly PowerStream Inc.) ("Alectra"), Veridian Connections Inc. ("Veridian"), Innisfil Hydro Distribution Systems Ltd ("InnPower"), Orangeville Hydro Ltd ("Orangeville Hydro") and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The South Georgian Bay/Muskoka region consists of the area roughly bordered by the Municipality of West Nipissing to the northwest, Algonquin Provincial Park to the northeast, Peterborough County and Hastings County to the southeast, Lake Scugog, York and Peel Regions to the south, Wellington County to the southwest and the Municipality of Grey Highlands to the west. Figure 1-1, on the following page, shows the boundaries of the South Georgian Bay/Muskoka Region.

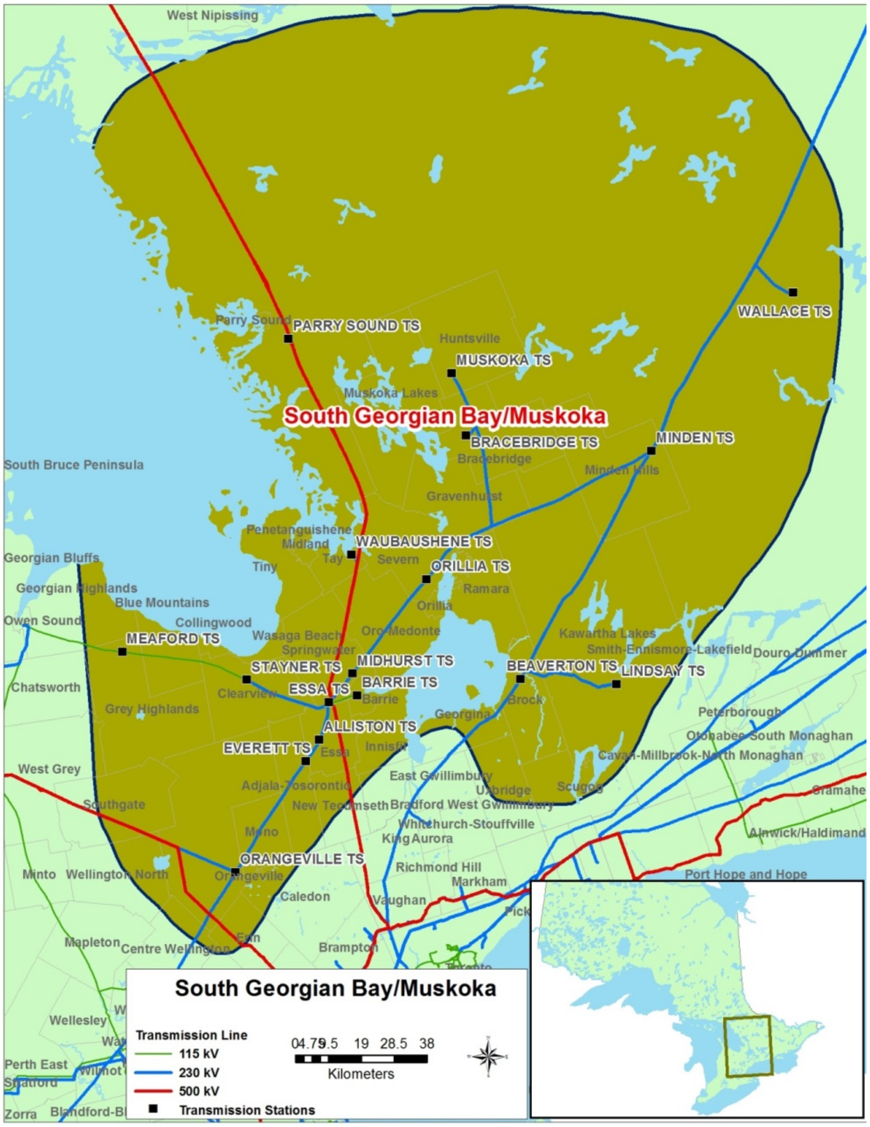

Figure 1-1 South Georgian Bay/Muskoka Region

1.1 Scope and Objectives

This RIP report examines the needs in the South Georgian Bay/Muskoka Region. Its objectives are to:

- Identify new needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plan to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and/or distribution facilities that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the Region's load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2016-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2016-2025 period and a wires plan to address them;
- Consideration of long-term needs identified in the Barrie-Innisfil and Parry Sound/Muskoka sub-region IRRPs.

As per the Regional Planning process, the Regional Plan for the region will be reviewed and/or updated at least every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can also be started earlier.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the regional characteristics
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the regional needs
- Section 7 describes the needs and provides the alternatives and preferred solutions
- Section 8 provides the conclusion and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is performed at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115kV and 230kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination or comprehensive planning is required an assessment is undertaken for any necessary investments directly by the LDCs (or customers) and the transmitter through a Local Plan ("LP"). These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. If there are needs that do not require regional coordination, the Study Team can recommend them to be undertaken as part of the LP approach discussed above. Otherwise, the approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region is identified in the NA phase, it is possible that different approaches could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP

[1] Also referred to as Needs Screening.

phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee ("LAC") in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timeline provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project-specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

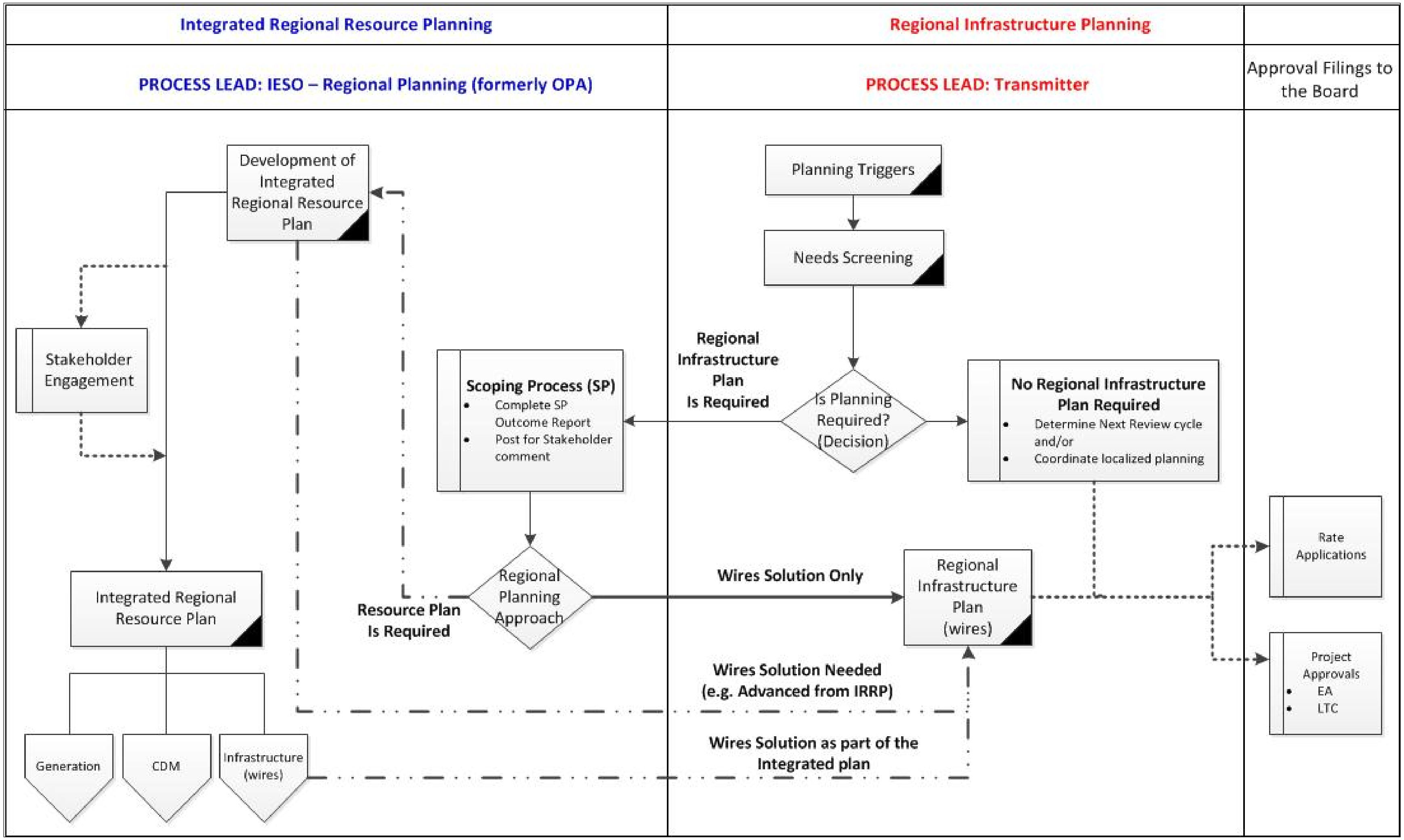

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. **Data Gathering:** The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects the following information and reviews it with the Study Team to reconfirm or update the information as required:
    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation ("DG") or CDM programs;
    - Existing area network and capabilities including any bulk system power flow assumptions;
    - Other data and assumptions as applicable such as asset conditions, load transfer capabilities, and previously committed transmission and distribution system plans.
2. **Technical Assessment:** The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. **Alternative Development:** The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.
4. **Implementation Plan:** The fourth and last step is the development of the implementation plan for the preferred alternative.

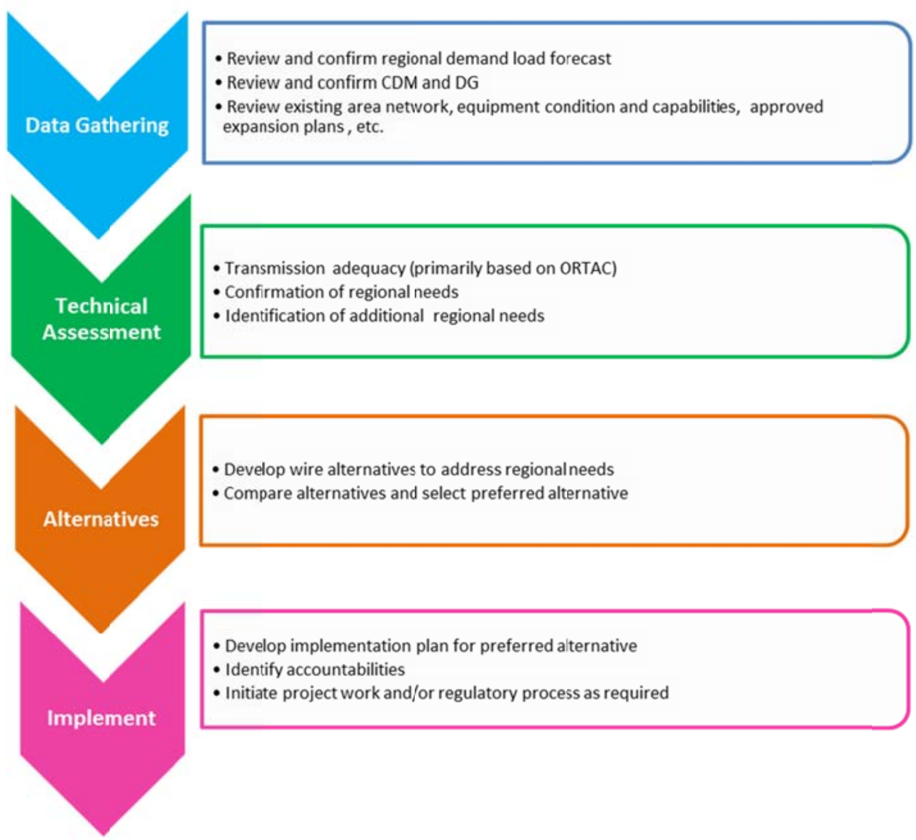

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE SOUTH GEORGIAN BAY/MUSKOKA REGION IS COMPRISED OF THE BARRIE/INNISFIL AND THE PARRY SOUND/MUSKOKA SUB-REGIONS. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TWO AUTO-TRANSFORMERS AT ESSA TS, THE 230KV TRANSMISSION LINES D1M, D2M, D3M AND D4M CONNECTING MINDEN TS TO DES JOACHIMS TS, THE 230KV CIRCUITS E8V AND E9V COMING FROM ORANGEVILLE TS AND THE SINGLE 115KV CIRCUIT S2S CONNECTING TO OWEN SOUND TS. THE 2015 WINTER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1,350 MW INCLUDING DIRECT TRANSMISSION-CONNECTED CUSTOMERS.

There are sixteen Hydro One-owned step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

The March 2013 South Georgian Bay/Muskoka Region NA report, prepared by Hydro One, considered the South Georgian Bay/Muskoka as a whole. Subsequently as a result of the Scoping Assessment, the South Georgian Bay/Muskoka Region was divided into two sub-regions, Barrie/Innisfil Sub-Region and Parry Sound-Muskoka Sub-Region. An IRRP was undertaken for each sub-region. A map of the South Georgian Bay/Muskoka Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 Barrie/Innisfil Sub-Region

The Barrie/Innisfil Sub-Region roughly encompasses the City of Barrie and the towns of Innisfil, New Tecumseth and Bradford West Gwillimbury. It includes the townships of Essa, Springwater, Clearview and Mulmur, Adjala-Tosorontio. The Barrie/Innisfil Sub-Region includes the areas supplied by Midhurst TS, Barrie TS, Everett TS, and Alliston TS, and transmission circuits E8V/E9V, E3B/E4B, and M6E/M7E.

3.2 Parry Sound/Muskoka Sub-Region

This sub-region roughly encompasses the Districts of Muskoka and Parry Sound and the northern part of Simcoe County. The Parry Sound/Muskoka Sub-Region includes the areas supplied by Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, and Minden TS, and transmission circuits M6E/M7E and E26/E27.

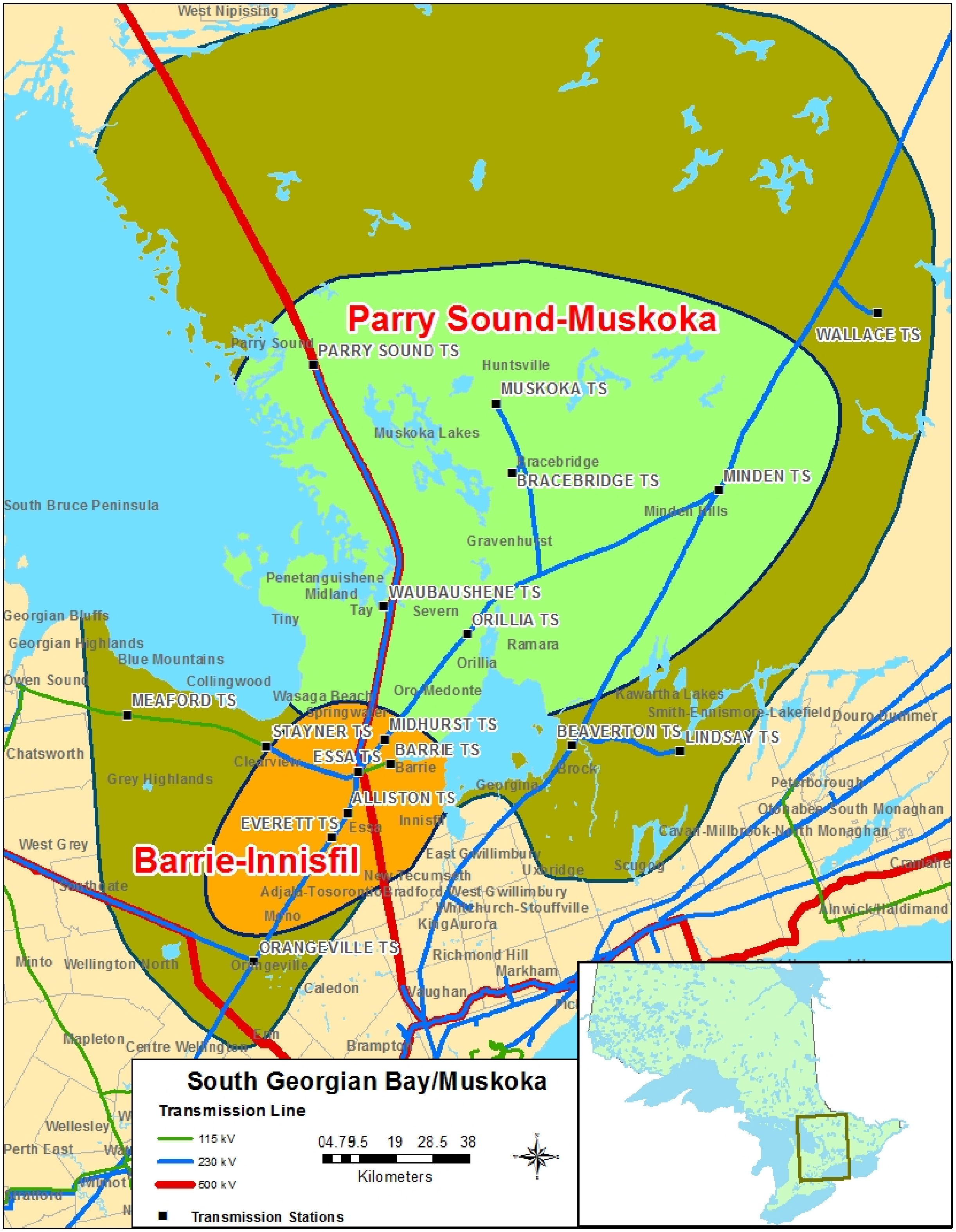

Figure 3-1 South Georgian Bay/Muskoka – Supply Areas

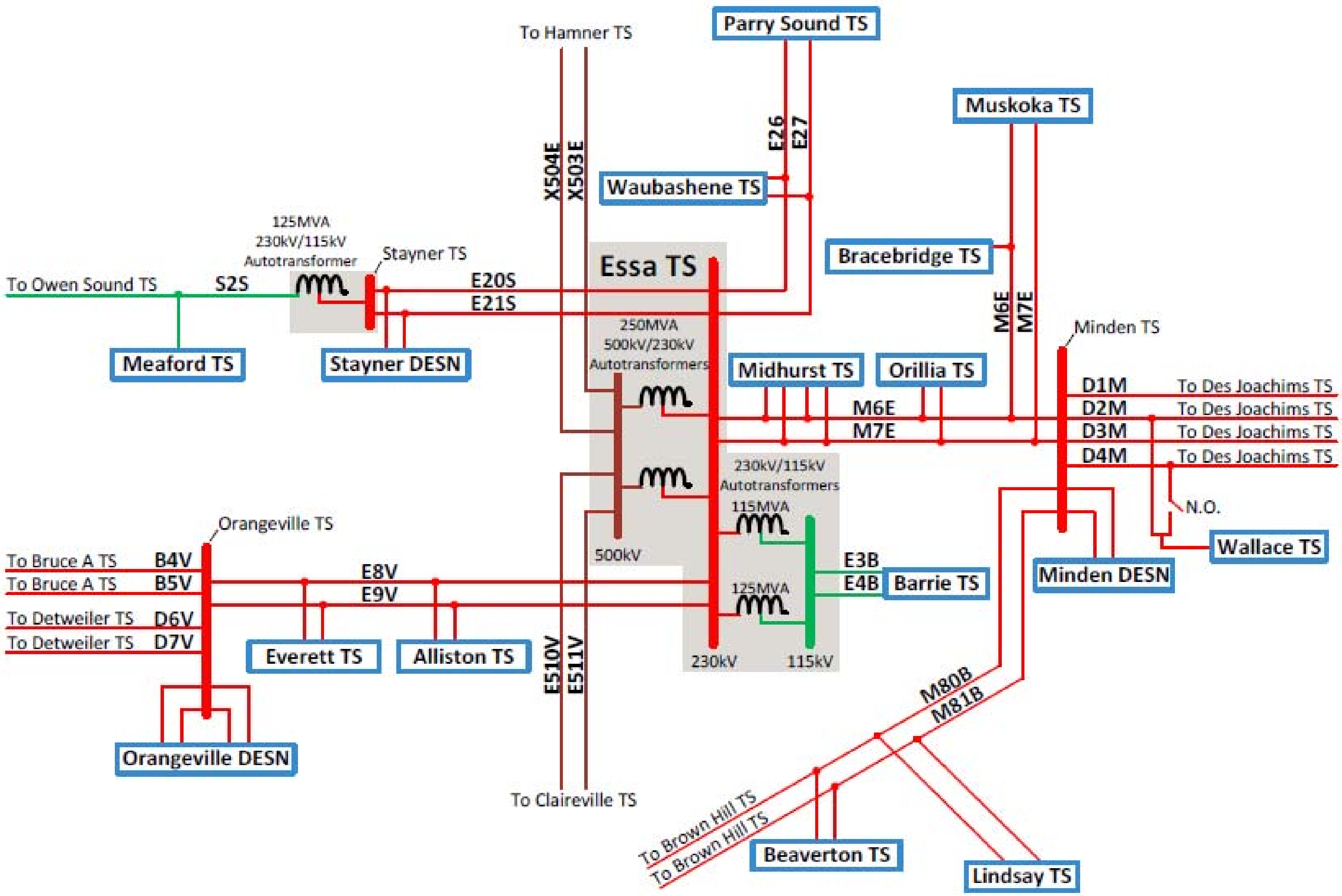

Figure 3-2 South Georgian Bay/Muskoka Region Single Line Diagram (Current)

4. TRANSMISSION FACILITIES COMPLETED OR CURRENTLY UNDERWAY OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR HAVE BEEN INITIATED, AIMED AT IMPROVING THE SUPPLY TO THE SOUTH GEORGIAN BAY/MUSKOKA REGION.

A brief listing of the development projects along with their in-service dates over the last 10 years is given below:

- Everett TS (2007) – Construction of new 50/85 MVA 230/44 kV Everett transformer station to alleviate load from Alliston TS, which was loaded beyond its capacity, and provide additional capacity for the load growth in the South Georgian Bay area.

- South Georgian Bay Transmission Reinforcement (2009) – Replacement of 27 km of 115 kV single circuit (S2E) between Essa TS and Stayner TS with a 230 kV double circuit (E20S/E21S) to improve supply reliability and prevent excessive post-contingency voltage decline. Replacement of two 50/83 MVA 115/44 kV step-down transformers at Stayner TS with two 75/125 MVA 230/44 kV transformers to provide additional capacity for the load growth in the South Georgian Bay area.

- Essa TS Shunt Capacitor Bank (2010) – Installation of one (1) 230 kV 245 MVAr shunt capacitor bank to address the need for added voltage support to increase the transfer capability of power from north to south and accommodate committed generation facilities north and west of Sudbury.

- Midhurst TS and Orillia TS Capacitor Banks (2012) – Installation of four (4) 44 kV 32.4 MVAr capacitor banks at Midhurst TS and Orillia TS (2 banks at each station) to minimize post-contingency voltage decline on the low voltage buses at both stations and improve the power quality for customers.

- Meaford TS Transformer Replacement (2015) – Like-for-like replacement of 25/42 MVA 115/44 kV transformers that were over 60 years old and nearing end-of-life.

The following development projects are expected to be placed in-service within the next 5-10 years:

- Barrie TS (2020/2021) – Hydro One is working with IESO, Alectra Utilities, InnPower, and Hydro One Distribution to replace the aging infrastructure while also addressing the growth related needs. The plan entails uprating 115kV lines E3B/E4B to 230kV, upgrading existing DESN transformer from 115/44 kV, 55/92 MVA to 230/44 kV, 75/125 MVA, increasing the number of feeders at Barrie TS, and removing the two 230/115 KV auto-transformers and 115 kV switchyard at Essa TS.

- Minden TS (2020-2021) – A recent station assessment has identified that power transformers T1 and T2, protection and control equipment, and select 44kV switchyard assets are degrading in condition and require replacement. Work involves replacing existing T1 & T2 three-phase power transformers with standard size three-phase power transformers, and upgrading and replacing the 44kV switchyard components.

- Orangeville (2024-2025) End-of-life transformers T1 and T2 (non-standard) will be replaced with two standard three-phase transformers sized 215.5-28 kV, 50/66.7/83.3 MVA units and T3 and T4 will be replaced with standard 215.5-44 kV, 75/100/125 MVA units. To standardize the configuration, the T1/T2 switchyard will be reconfigured as a single 230-28 kV switchyard and the two existing 44 kV feeders, M45 and M46, will be relocated and supplied from the T3/T4 DESN. Associated end-of-life protection, control and telecom assets and station service equipment is also planned for replacement.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the South Georgian Bay/Muskoka Region is expected to increase at an annual rate of approximately 1.17 % between 2016 and 2034. The growth rate varies across the Region but an overall coincident growth in the Region is illustrated in Figure 5-1. The winter and summer, gross and net non-coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix C and D.

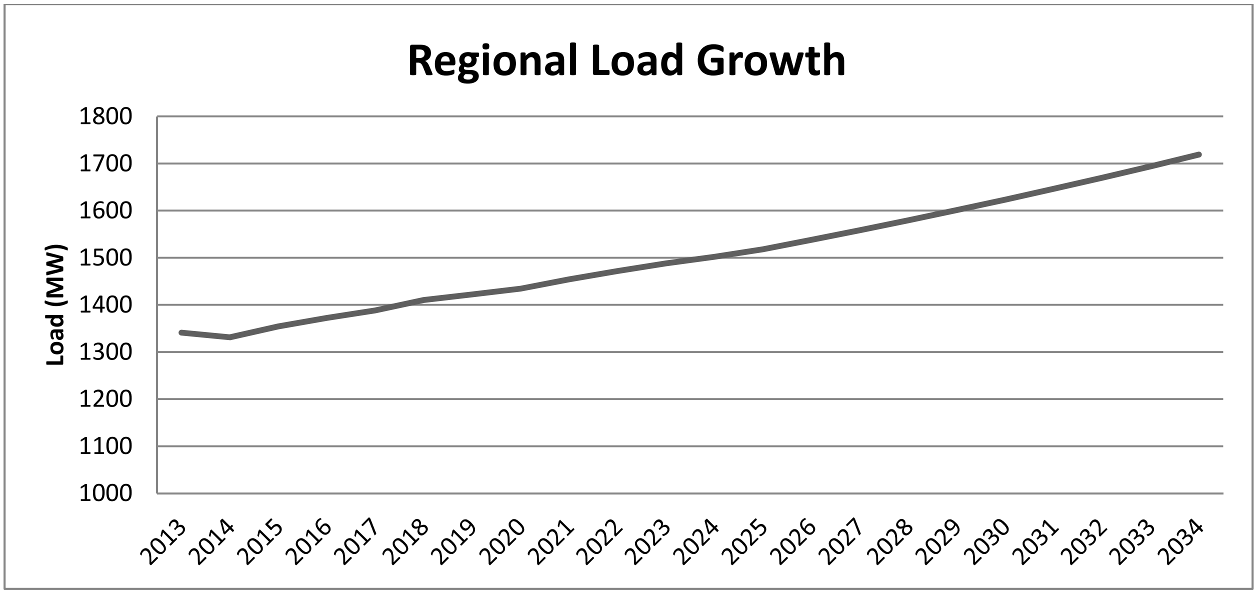

Figure 5-1 South Georgian Bay/Muskoka Region Winter Coincident Net Load Forecast

Prior to the RIP's kick-off, the Study Team was asked to confirm the load forecast for all stations in the Region provided for previous assessments. The RIP's load forecast for South Georgian Bay/Muskoka Region did not have a significant revision compared to the IRRP's load forecast.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2014 – 2034.
- The Region is winter peaking, however five out of sixteen stations in the Region are summer peaking (Alliston TS, Barrie TS, Everett TS, Midhurst TS and Orangeville TS T1/T2 DESN). Therefore, this assessment is based on both winter and summer peak loads, as appropriate.
- "Barrie Area Transmission Upgrade project" to be completed by the end of 2020.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-

voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.[2] Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR") or the winter 10-Day LTR depending on what season the station peaks.

- Barrie TS is forecasted to experience the highest average yearly growth rate of any TS in the study area over the 20 year planning period for all growth scenarios.

[2] These power factor assumptions differ from those in the IRRP, which assumes a 90% lagging power factor for all stations. This results in differences in need dates for station capacity when comparing the IRRP and the RIP.

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE SOUTH GEORGIAN BAY/MUSKOKA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, six regional assessments have been conducted for the South Georgian Bay/Muskoka Region. The findings of these studies are an input to the RIP:

1. South Georgian Bay/Muskoka Region Needs Assessment Report – March 3, 2015 [2]
2. South Georgian Bay/Muskoka Region Scoping Assessment Report – June 22, 2015 [3]
3. Local Planning Report – Orangeville TS End of life ("EOL") Replacement – May 27, 2016 [4]
4. Barrie/Innisfil Sub-Region IRRP – Dec. 16, 2016 [5]
5. Parry Sound/Muskoka Sub-Region IRRP – Dec. 16, 2016 [6]

The NA, IRRP, and LP studies identified a number of regional needs based on the forecast load demand over the near to mid-term. A detailed description and status of plans to meet these needs is given in Section 7.

Based on the regional growth rate referred to in Section 5, this RIP reviewed the loading on transmission lines and stations in the South Georgian Bay/Muskoka Region assuming Essa/Barrie and E3B/E4B upgrade to be completed by 2020/2021, Minden DESN transformer replacement and 44kV upgrade to be completed by November 2020/2021, and Orangeville transformer replacement and station reconfiguration to be completed by October 2024/2025.

Sections 6.1-6.3 present the results of this review and Table 6-1 lists the Region's near, mid and long-term needs identified in both the IRRP and RIP phases.

Table 6-1 Near, Mid and Long-Term Needs in the South Georgian Bay/Muskoka Region

Type	Section	Needs	Timing
Station Capacity	7.1	Barrie TS (existing 115/44kV configuration)	Today
	7.2	Barrie TS (future 230/44kV configuration)	2031[3]
	7.7	Everett TS	2027
	7.3	Parry Sound TS	Today
	7.7	Waubaushene TS	2027[4]
Transmission line capacity	7.1	E3B/E4B forecasted to exceed their Load Meeting Capability (LMC)	2019
Load Restoration	7.4	Load Restoration for loss of double-circuit M6E/M7E	Today
Load Security	7.7	Load Security for M6E/M7E – load growth may exceed its 600 MW LMC	Early 2030s
Outage Duration and Frequency	7.5	44kV Parry Sound/Muskoka Sub-Region experience below average performance w.r.t frequency and duration of outages	Today
Distribution Feeder Capacity	7.6	The one Barrie TS feeder that is designated to InnPower will exceed its normal operating rating	2020
End of Life	7.8	Minden TS (two transformers and associated ancillary equipment)	2020/2021
	7.9	Orangeville TS (All four transformers)	2024/2025
	7.3	Parry Sound TS (one transformer, T2)[5]	2021

6.1 115kV and 230kV Transmission Facilities

The South Georgian Bay/Muskoka Region is comprised of mostly 230kV circuits, M6E/M7E, E8V/E9V E26/E27, E20S/E21S, D1M/D2M/D3M/D4M, M80B/M81B, and one pair of 115kV circuits E3B/E34B, supplying the Barrie/Innisfil and Parry Sound/Muskoka Sub-Regions and other areas outside the two sub-regions. Refer to Figure 3-2 for existing facilities in the Region.

[3] The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

[4] The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacitor banks have a 90% power factor and stations with low-voltage capacitor banks have a 95% power factor. Since Waubaushene TS has low voltage capacitor banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP.

[5] Parry Sound TS was placed in service in 1970 and has been supplying power to parts of the Region for almost 50 years. Field crews have recently observed that one of the two power transformers is in poor operating condition.

Bulk system planning is being conducted by the IESO and is also informed by government policy such as the Long-Term Energy Plan (LTEP). The next LTEP is expected to be issued in 2017. Any outcomes impacting planning decisions will be later updated in this regional planning report.

6.2 Barrie/Innisfil Sub-Region's Step-Down Transformer Station Facilities

There are four step-down transformer stations in the Barrie/Innisfil Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in Barrie/Innisfil Sub-Region

Station	DESN	Voltage Transformation
Alliston TS	T2/T3/T4	230/44kV
Barrie TS	T1/T2	115/44kV
Everett TS	T1/T2	230/44kV
Midhurst TS	T1/T2	230/44kV

Based on the LTR of these transformer stations, additional transformation capacity is required at Barrie TS (115/44kV) since the station exceeded its LTR in 2015. This will be addressed by the proposed replacement and upgrade of Barrie TS and circuits E3B/E4B (see details in Section 7.1). In 2031, the upgraded Barrie TS is forecasted to reach its capacity.[6] Since this is a long-term capacity need, it will be monitored and investigated further in the next cycle of the Regional Planning Process. The upgrade of Barrie TS will also address the InnPower distribution feeder capacity need that arises in 2020 – see Section 7.6 for more information.

Everett TS is expected to reach its LTR in approximately ten years. The station's LTR of 86 MW is presently limited by the tap ratio setting of the low voltage current transformers (CT). As the capacity need date approaches, the tap ratio will be increased and the capacity of the station will increase to the LTR of the transformers. The solution to address this capacity need is further described in Section 7.7.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-3.

[6] The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

Table 6-3 Transformation Capacities in the Barrie Innisfil Sub-Region

Station	LTR (MW)	2016 Summer Peak (MW)	Relief Required By
Alliston TS (T2)	100	118	-
Alliston TS (T3/T4)	101		-
Barrie TS (T1/T2)	109	102	Immediately
Barrie TS (uprated)	161.5[7]	102	The uprated Barrie TS will exceed its capacity by 2031
Everett TS (T1/T2)	86	70	2027
Midhurst TS (T1/T2)	163	105	-
Midhurst TS (T3/T4)	150	106	-

6.3 Parry Sound/Muskoka Sub-Region's Step-Down Transformer Station Facilities

There are five step-down transformer stations in the Parry Sound/Muskoka Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in Parry Sound Muskoka Sub-Region

Station	DESN	Voltage Transformation
Bracebridge TS	T1	230/44kV
Muskoka TS	T1/T2	230/44kV
Orillia TS	T1/T2	230/44kV
Parry Sound TS	T1/T2	230/44kV
Waubaushene TS	T5/T6	230/44kV

Under peak conditions in winters between 2013 and 2016, Parry Sound TS transformers supplied up to 6 MW over their LTR. Although the 2017 winter station peak only reached 44 MW (8 below LTR), the immediate addition of 44 kV capacity is required to provide relief to Parry Sound TS. Two alternatives to address this need are discussed further in Section 7.3.

Waubaushene TS is expected to exceed its LTR of 105 MW by 2027[8]. Plans to mitigate loading problems in Waubaushene TS are discussed in Section 7.7 as long-term needs.

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[7] The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

[8] The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacitor banks have a 90% power factor and stations with low-voltage capacitor banks have a 95% power factor. Since Waubaushene TS has low voltage capacitor banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP.

Muskoka TS, Orillia TS and Bracebridge TS are adequate to meet the net demand over the study period.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-5.

Table 6-5 Transformation Capacities in the Parry Sound/Muskoka Sub-Region

Station	LTR (MW)	2017 Winter Peak (MW)	Relief Required By
Bracebridge TS (T1)	84	11	-
Muskoka TS (T1/T2)	198	145	-
Orillia TS (T1/T2)	177	115	-
Parry Sound TS (T1/T2)	52	44	Immediately
Waubaushene TS (T5/T6)	104[9]	81	2027

The winter and summer non-coincident load forecasts for all stations in the Region are given in Appendix C and Appendix D, respectively.

6.4 Areas outside of Sub-region

The table below lists the seven transformer stations that are outside of the Sub-regions

Table 6-6 Transformation Capacities in the Areas outside of Sub-Region

Station	DESN	Voltage Transformation
Beaverton TS	T3/T4	230/44kV
Lindsay TS	T1/T2	230/44kV
Meaford TS	T1/T2	115/44kV
Minden TS	T1/T2	230/44kV
Orangeville TS	T1/T2	230/44/27.6kV
Orangeville TS	T3/T4	230/44kV
Stayner TS	T3/T4	230/44kV
Wallace TS	T3/T4	230/44kV

[9] The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacitor banks have a 90% power factor and stations with low-voltage capacitor banks have a 95% power factor. Since Waubaushene TS has low voltage capacitor banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP..

Table 6-7 Transformation Capacities in the Areas outside of Sub-Region

Station	LTR (MW)	2017 Winter Peak (MW)	Relief Required By
Beaverton TS	213	72.2	-
Lindsay TS	183	76.6	-
Meaford TS	58	31.7	-
Minden TS	58	50.6	-
Orangeville TS (T1/T2) 27.6 kV	110	32	-
Orangeville TS (T1/T2) 44 kV	56	21	-
Orangeville TS (T3/T4)	118	71	-
Stayner TS	203	124.5	-
Wallace TS	54	33.3	-

Based on peak load conditions, all the transformers are within their respective LTRs.

End-of-Life Equipment Replacements

Recent station assessments have identified near-term end-of-life needs at Orangeville TS and Minden TS, and a recent condition assessment of Parry Sound TS has revealed that one of the existing power transformers at the station is in a very poor condition and must be replaced in the near-term.

- The Minden TS facility was originally built in 1950. Its assets are degrading in condition and require replacement in 2020-2021. Existing 230/44 kV T1 and T2 three-phase power transformers and associated ancillary equipment will be upgraded with the smallest available standard size 230/44 kV three-phase power transformers. As a result, the rating of transformers will increase from 25/33/42 to 50/66.7/83.3 MVA. See Section 7.8 for more information.

- Switchyards at Orangeville TS were placed in-service in 1960s and several of the assets are at the end of their useful lives including all four transformers (T1, T2, T3, and T4). In addition, the existing 210-44-28 kV winding configuration on T1 and T2 is non-standard which introduces challenges with maintenance, spare parts and future replacement strategies. The existing switchyard supplied by T1/T2 consists of 28kV feeders, plus additional two 44kV feeders.

  After reviewing different alternatives, the preferred solution is to replace T1/T2 with standard three-phase 215.5-28kV transformers, while T3 and T4 will be replaced with standard 215.5-44kV units. The existing 44kV feeders in the T1/T2 DESN will be relocated to the T3/T4 DESN. Due to this modification, the T3/T4 rating will change from 50/67/83 to 75/100/125 MVA, while the T1/T2 rating will change from 75/100/125 to 50/66.7/83.3 MVA. See Section 7.9 for more information.

- Parry Sound TS was placed in service in 1970 and has been supplying power to parts of the Region for almost 50 years. Field crews have recently observed that one of the two power transformers is in poor operating condition which has triggered a station assessment which will be undertaken by Hydro One's Station Sustainment team in 2017. The team will assess all of the Parry Sound TS equipment to determine when the various components need to be replaced in order to avoid end-of-life failures. See Section 7.3 for more information.

It is worth noting that there are potential bulk power system elements that are also at the end of their useful lives. These include 230 kV transmission lines D1M/D2M, E8V/E9V, and M6E/M7E. IESO will lead the bulk power system studies for these lines in coordination with Hydro One.

7. REGIONAL PLANS

THIS SECTION DISCUSSES THE NEEDS, WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES SOLUTION FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS IN THE SOUTH GEORGIAN BAY/MUSKOKA REGION. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRPS FOR THE BARRIE/INNISFIL AND THE PARRY SOUND/MUSKOKA SUB-REGIONS.

The near-term needs arise over the first five years of the study period (2016 to 2020) and the mid-term needs cover the second half of the study period (2021-2025).

7.1 Increase Transformation Capacity in Barrie/Innisfil Sub-Region

Description

The Barrie/Innisfil Sub-Region includes the areas supplied by Midhurst TS, Barrie TS, Everett TS, and Alliston TS, and transmission circuits E8V/E9V, E3B/E4B, and M6E/M7E.

Over the next 10 years, the load in this Sub-Region is forecasted to increase at a rate of approximately 2.5% annually.

Based on the net forecasts (DG and CDM incorporated) in the Sub-Region, adequate transformation capacity is available at Midhurst TS and Alliston TS to maintain reliable supply to meet the demand over the near and mid-term period.

Barrie TS is a summer-peaking station and currently exceeds its normal supply capacity based on both gross and net summer demand. Circuits E3B/E4B that supply radially to Barrie only are also approaching their LMC, which they are expected to exceed by 2019.

Everett TS has a long term need which is discussed in Section 7.7.

Recommended Plan and Current Status

During the regional planning process, the Study Team considered multiple alternatives to address the transformation capacity and end-of-life needs in this Sub-Region.

The 44 kV switchyard at Barrie TS was placed in-service in 1962 and the assets are in degraded condition and are in need of replacement. Previous assessments have suggested the replacement of aged and degraded infrastructure, including both transformer banks, low voltage switchgear, capacitor banks and associated ancillary equipment. Loading on the Barrie TS T1/T2 yard has steadily increased since 2013 and has reached a point where it is encroaching on the LTR rating of the transformer banks, and limiting further connections downstream from the station.

Since Barrie TS currently exceeds its supply capacity, the like-for-like option would not result in any increase in capacity. Instead it was proposed to remove T1/T2 (230/115kV) at Essa TS and replace T1/T2 (55/95MVA, 115/44kV) at Barrie TS with one pair of transformers T1/T2 (75/125MVA, 230/44kV) at Barrie TS, along with uprating circuits E3B/E4B from 115kV to 230 kV. This would increase the Barrie DESN capacity by 50MW, and increase the LMC of E3B/E4B as well.

The Study Team recommended to rebuild and uprate Barrie TS as the best solution to meet the transformation capacity need in the Sub-Region. Hydro One is currently developing this plan, called the 'Barrie Area Transmission Upgrade project'. Class Environmental Assessment (EA) is in progress for this project. Since circuits E3B and E4B are 9km in length, an OEB Section 92 approval is required for this project. It will be initiated once the engineering estimate is completed for this project by early 2018.

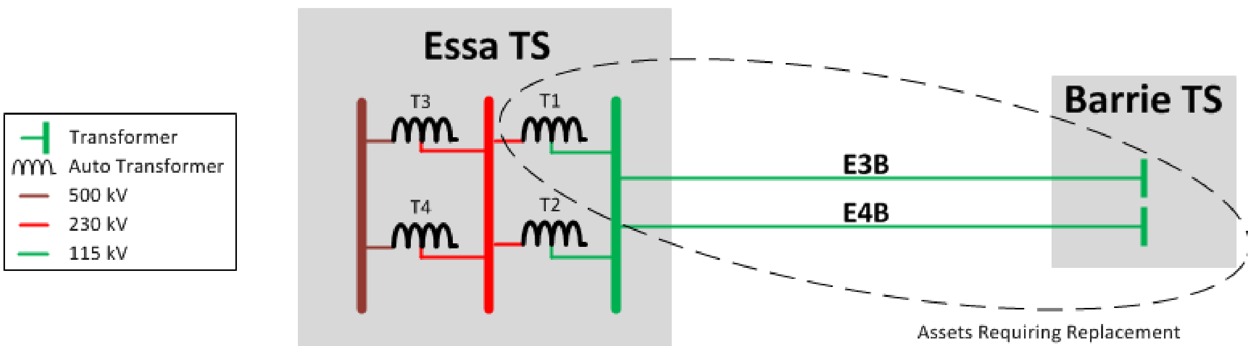

Figure 7-1 Current Arrangement of Essa TS, Barrie TS, and Circuits E3B/E4B

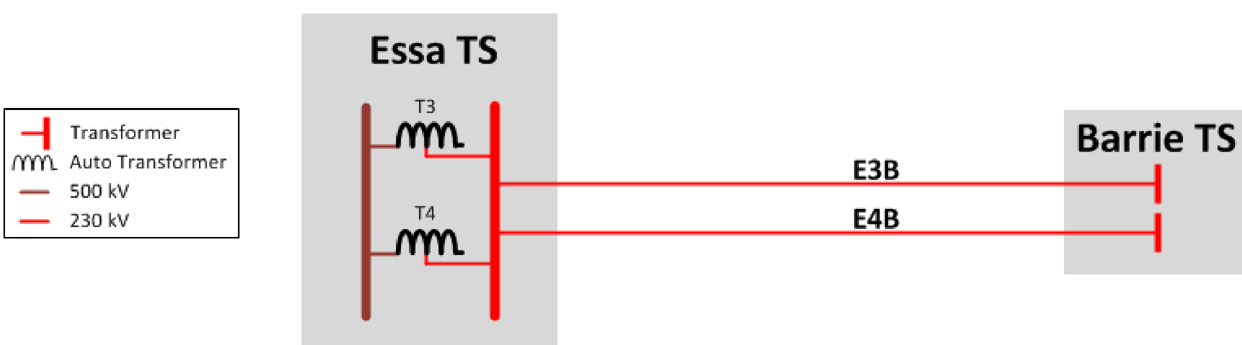

Figure 7-2 New Configuration of Essa/Barrie Supply to Barrie DESN

The total cost of this project is estimated to be $84M. This estimate includes the cost of transmission as well as distribution investments which include the station's construction, its connection arrangements as defined above, and feeder egress to the distribution risers outside of the station.

7.2 Transformation Capacity Need at Uprated Barrie TS

Description

Over the 20 year planning period, Barrie TS will experience the biggest growth out of all the transformer stations, which is influenced by the recent continued development of data centers in the City Of Barrie, and greenfield residential development in the annexed lands in south Barrie, in addition to the proposed industrial and commercial development at Innisfil Heights near Highway 400. With the forecast data collected, it is determined that the uprated Barrie TS will exceed its LTR by 2031.

Proposed Alternatives and Recommended Plan

One of the alternatives to accommodate load growth in Barrie/Innisfil Sub-Region, is to build a new 230 kV station via the idle Hydro One right-of-way, a corridor currently being utilized by the existing 13M3 feeder, which could provide an additional 150MW capacity.

The additional feeders that are being built by Alectra will facilitate the transfer of up to 27 MW of load from Barrie TS to Midhurst TS by 2019 and will defer a capacity need at the upgraded Barrie TS to 2031. This need will be monitored and investigated further in the next cycle of the Regional Planning Process. Long-term options beyond 2026 are discussed in Section 7.7.

7.3 Increase Transformation Capacity in Parry Sound/Muskoka Sub-Region

Description

The load forecast reflects an annual growth of 0.82 % in Parry Sound/Muskoka area throughout the study period.

Based on historical demand data and the station's net demand forecast, Parry Sound TS T1/T2 has already exceeded its respective normal supply capacity and will continue to do so over the study period. Parry Sound TS is a winter peaking station with a winter LTR of 52 MW. It had exceeded its LTR by as much as 6 MW in the winters of 2013 to 2016, however the 2017 winter peak was 8 MW below the LTR.

Waubaushene TS is expected to be loaded beyond its winter LTR (104.5 MW) by 2026-27. Recommended plans for addressing this need are discussed in Section 7.7. Although the summer peak is not expected to exceed the summer LTR over the study period based on the net demand forecast, historical summer peak demand (2015/2016) at Waubaushene TS was approaching the summer LTR. The

Study Team will continue to monitor the summer and winter demand closely and explore opportunities to manage the peak demand growth at Waubaushene TS.

Therefore, based on the current load forecasts, additional transformation capacity relief is required for both Parry Sound TS and Waubaushene TS to accommodate the load growth and improve reliability in this sub-region.

Recommended Plan and Current Status

There are two options that have been proposed to address the capacity need at Parry Sound TS: a) Distribution load transfer and b) upsize transformers at Parry Sound TS.

Option a) To accommodate the load growth at Parry Sound TS, 6 MW of Parry Sound's load can be transferred over to Muskoka TS. For this load transfer to take place, Hydro One Distribution will need to seek approval to construct a new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS, which would cost approximately $7M and would be in service by 2020. This option will address the near term supply needs at Parry Sound TS.

Option b) Hydro One has identified that Parry Sound TS (T1/T2) transformer T2 is in poor condition and must be replaced in the near-term. The second transformer is also identified to be reaching the end of its useful life over the next 5-10 years. As a result, Hydro One is planning to replace T2 which is a non-standard 25/42 MVA, 230/44 kV transformer with a 50/83 MVA unit which is currently the smallest standard size transformer at this voltage level. In addition, Hydro One will also consider advancing the replacement of the companion transformer, T1, since it will be much more efficient and economical to replace both transformers at the same time. The additional cost to replace T1 is approximately $8M. This would address the near- and long-term capacity need at Parry Sound TS; eliminate the need to spend $7M on the 44 kV sub-transmission line; and provide better reliability for customers. The advancement cost of replacing T1 is approximately $2M. The new transformers at Parry Sound TS would be expected in service by 2021.

Since the peak demand growth is relatively slow in this area, conservation and local demand management and distributed generation can be used in the meantime to defer capacity-related upgrades at these stations. Results from the Parry Sound/Muskoka Local Achievable Potential ("LAP") study can help the Study Team better understand cost and feasibility of using distributed energy resources and local demand management options to manage electricity demand growth in the area.

Going forward, the Study Team will need to assess the cost-benefit of the various options to address supply capacity needs at Parry Sound TS and to determine whether it would be cost-effective to advance the replacement of the companion transformer, T1, at Parry Sound TS at this time. The decision related to the end of life replacement of the transformers at Parry Sound TS will need to be made by mid-2018 so that the transformers can come into service by early 2021.

With the future increased station capacity at Parry Sound TS, the long-term capacity need at Waubaushene TS could be addressed via permanent load transfers since transfer capability already exists between the two stations.

7.4 Parry Sound/Muskoka Load Restoration Assessment

Description

The Parry Sound/Muskoka load restoration need was identified in the Parry Sound/Muskoka Sub-Region IRRP report, which indicated that for the loss of two transmission elements (M7E/M6E transmission lines) the load interrupted with current circuit configuration during peak periods will exceed load restoration criteria.

M6E/M7E transmission lines currently supply 465 MW of peak demand. In the event of a double circuit outage, all customers on this double circuit will be interrupted for more than 30 minutes. As per ORTAC criteria, this constitutes a violation unless 215 MW of peak load can be restored within 30 minutes for a M76/M7E outage during a peak demand period.

Proposed Alternatives and Recommended Plan

In collaboration with the Study Team, a recommendation for the load restoration was identified in the Region. One of the alternatives considered was resupplying load from the 44 kV system. However, this will only supply about 20-30 MW.

The Study Team is recommending that an investment in motorized disconnect switches (MDS) should be made, which can be used to isolate sections of the transmission lines within 30 minutes. These switches would be installed at the Orillia TS junction. Another alternate solution was installing breakers on the line instead of motorized switches, since breakers can immediately isolate a section faulted line.

Breakers would be useful if the loading on the double circuit was more than 600 MW, however given the uncertainty of future load growth and the cost of breakers which are 3-4 times more expensive than motorized switches, the Study Team recommended to proceed with the installation of two 230 kV motorized switches at Orillia TS. The switches will be in service by 2021 at a cost of $5-7M.

In the event of a double M6E/M7E outage, with the motorized disconnect switches installed, at least 50% of the load on this double circuit supply can be restored within 30 minutes, meeting the ORTAC 30 minute load restoration criteria.

IESO has issued a hand-off letter to Hydro One to initiate the development work for the installation of motorized disconnect switches at Orillia TS. The development work is currently underway, in the budgetary estimating phase.

7.5 Outage Duration And Frequency in Parry Sound/Muskoka Sub-Region

Description

Load in the Parry Sound/Muskoka Sub-Region is supplied via:

- Local generation resources;
- 230 kV transmission system;
- 44 kV sub-transmission and low-voltage distribution system.

Customers supplied by Muskoka TS and Parry Sound TS in this sub-region experience more frequent and prolonged outages, almost double the provincial performance, which can impede economic development. Most of the incidents occur on the 44kV sub-transmission system due to longer feeder length as compared to the average length of feeders in the rest of the province. Longer lines increase exposure to tree contact and require additional time for repair crews to identify and isolate faulted sections.

Recommended Plan and Current Status

Hydro One Distribution currently has a number of on-going maintenance and outage mitigation initiatives. These are listed below:

- Vegetation Management Program
- Line Patrols
- Mid-cycle Hazard Tree Program
- Distribution Management System and Grid Modernization

In addition, Hydro One Distribution will assess other options as well and provide an update to the communities and LACs on plans to improve the 44 kV system by the end of 2017.

Another option to mitigate outages on the 44 kV is to build new distribution lines from Bracebridge TS, and transfer some load over to Bracebridge TS, since currently the industrial load demand at that station has been decreasing over the last several years.

Cost-Benefit/Responsibility will be considered by Hydro One Distribution, Lakeland Power and Veridian Connections to improve reliability performance of the 44 kV sub-transmission system, which will be completed by the end of 2017.

7.6 Distribution Feeder Capacity to Supply InnPower

Description

Currently six feeders in Barrie TS are used to supply Alectra, and one feeder supplies InnPower. From the forecast provided, the Study Team concluded in the IRRP that InnPower will exceed its load capacity of

25 MW, which its existing feeder can supply, by 2020. An additional feeder will be required for InnPower starting 2020.

Recommended Plan and Current Status

The uprated Barrie TS will include eight feeders, as opposed to the current seven feeders that exist today. This additional feeder can be used in addition to the existing InnPower dedicated feeder to supply InnPower load.

7.7 Long Term Regional Plan

As discussed in Section 5, the electricity demand in South Georgian Bay/Muskoka Region is forecasted to grow at 1.46% annually over the next 10 years, and at a slightly lower average rate of 1.17% from 2016-2034. Similar trend is also expected in the long term period where the load is expected to increase by approximately 1% annually from year 2024 to 2034 in the Parry Sound/Muskoka Sub-Region, while 1.9% in the Barrie/Innisfil Sub-Region. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

Parry Sound/Muskoka

Currently the Muskoka-Orillia 230kV subsystem supplies up to 454 MW. Based on electricity demand growth, Muskoka-Orillia is not expected to exceed its LMC of 600 MW until early 2030.

The following options will be revisited in the next regional planning cycle:

- Upgrade the transmission lines in the area, thus increasing M6E/M7E LMC.
- Connect a 20 MW generation on the Muskoka-Orillia 230 kV system
- Results from the Parry Sound/Muskoka LAP study can help the Study Team better understand cost and feasibility of using distributed energy resources and local demand management options to manage electricity demand growth in the area.

Electricity demand forecast is expected to exceed Waubaushene TS system's capability by 2026-27. To manage this long term growth, 4MW load can be transferred from Waubaushene TS to Orillia TS. More transfer capability between Waubaushene TS and Midhurst TS will be available upon completion of 'Barrie Area Transmission Upgrade' project. With the potential increase of the capacity at Parry Sound TS, there will be capability to transfer additional load from Waubaushene TS to Parry Sound TS.

Barrie/Innisfil

Barrie/Innisfil sub region is the area supplied by Midhurst TS, Barrie TS, Alliston TS, and Everett TS. The planning load forecast projects that load will exceed the aggregate capacity of these transformers by

2033. Due to the uncertainty of long term forecasts, IESO will monitor the area and an annual update to the Study Team on demand, conservation and DG trends.

Everett TS is forecasted to exceed its LTR (86.4 MW) by 2026. This LTR is currently limited by the CT ratio. Hydro One is now able to update CT ratio whenever desired which would increase the LTR. The new LTR may defer the capacity need at Everett TS beyond the study period.

In the Barrie area, load is expected to exceed the area's LMC (Midhurst TS and Barrie TS capacity) by 2031. Alectra Utilities and InnPower will undertake a LAP study to address the long term needs for Barrie TS service area to determine the conservation and demand management potential in the area beyond the conservation values already accounted for in the planning forecast.

Metrolinx is planning to electrify the Barrie GO train lines and has approached Hydro One, requesting 40-50MW of capacity. The new 230kV circuits from Essa TS to Barrie TS would provide adequate capacity and tapping positions for Metrolinx's substation, however the supply capacity at Essa TS may present some limitations. Therefore the Metrolinx project is being closely monitored by the IESO and Study Team.

7.8 Minden TS End of Life Assets

Description

The Minden T1/T2 yard is a unique DESN which transforms voltages from 230 kV to 44 kV and facilitates load delivery to the Minden area via four (4) feeders supplying the Hydro One distribution system. This station was built in the 1950s and is primarily composed of older equipment. The T1 and T2 transformers are each rated at 25/42 MVA and are non-standard as per the current standards. Non-standard and obsolete equipment introduces complexities in repairing failures and difficulties in finding and installing spare equipment. The transformers are currently beyond their expected service life and their condition is deteriorating and leak risk is increasing. Furthermore, due to the station's unique configuration, an outage on the high voltage bus or a transformer will cause load loss, which does not occur in a standard DESN layout.

Alternatives and Recommended Plan

The following alternatives were considered to address the end of life situation at Minden TS:

- Maintain Status Quo ("do nothing"): This alternative was considered and rejected as it does not address the risk of failure due to aging equipment and would result in increased maintenance expenses and reduced supply reliability for customers.
- Like-for-Like replacement of assets: This alternative would require the purchase and installation of custom, non-standard, 25/42 MVA transformers and associated equipment which is not justifiable based on the load forecast and would cost more than the smallest standard 230/44 kV transformers which are 50/83 MVA.

- Replace transformers with standard 50/83 MVA units and reconfigure switchyard: This alternative will include replacing the existing transformers with 50/83 MVA units and reconfiguring part of the switchyard to meet standard DESN layout and improve supply reliability to customers.

The preferred alternative is for Hydro One to replace the existing transformers with standard 50/83 MVA units and reconfigure the switchyard to allow it to operate the way a standard DESN should. The new equipment is expected to have a service life of over 50 years and will be able to supply the forecasted load growth in the Minden area. This option allows for easy installation of spare equipment in case failures occur and the improved reliability will improve the customer satisfaction in the area. This refurbishment project is currently planned to be completed in 2020-2021 at a cost of $17 million.

7.9 Orangeville TS End of Life Assets

Description

Orangeville TS is a transmission station that provides 230 kV switching as well as transformation of 230 kV to 44 kV and 27.6 kV. Orangeville TS serves as the supply for Hydro One Distribution and Orangeville Hydro customers in and around the town of Orangeville via two DESN switchyards, T1/T2 (27.6 and 44 kV) and T3/T4 (44 kV). The 27.6 kV and 44 kV switchyards were placed in-service in 1969 and many assets are in a degraded condition and in need of replacement. Previous assessments have identified that all four transformers T1, T2, T3, and T4 and associated equipment are candidates for replacement. In addition, the existing 210-44-28 kV winding configuration on T1 and T2 is non-standard, which introduces challenges with maintenance, sparing and future replacement strategies.

In recent discussions, Orangeville Hydro expressed its intent to further increase its use of the 27.6 kV feeders supplied from Orangeville TS. Consequently, Orangeville Hydro intends to reduce the number of customers and stations connected to the 44 kV feeders M3 and M5.

Alternatives and Recommended Plan

The following alternatives were considered to address the end of life issue at Orangeville TS:

- Maintain Status Quo (“do nothing”): This alternative was considered and rejected as it does not address the risk of failure due to aging equipment and would result in increased maintenance expenses and reduced supply reliability for customers.
- Like-for-Like replacement of assets: This alternative would require the purchase and installation of custom, non-standard, transformers and associated equipment which is not justifiable based on the cost of custom equipment, Orangeville Hydro’s supply voltage plans, and Hydro One’s effort to standardize non-standard station configurations.
- Replace transformers with standard units and reconfigure 27.6 kV and 44 kV switchyards: This alternative aims to replace the existing T1/T2 transformers with standard units, standardize the configuration of the T1/T2 switchyard by converting it to a typical 230/27.6 kV DESN, replace

the aging T3/T4 230/44 kV transformers to maintain overall 44 kV capacity, and relocate 44 kV feeders to the new T3/T4 DESN.

The preferred alternative is for Hydro One to replace the existing T1/T2 230/44/27.6 kV 75/125 MVA transformers with two 230/27.6 kV 50/83 MVA units and reconfigure the dual voltage switchyard to a standard DESN that would supply the 27.6 kV load. Hydro One will also replace the existing T3/T4 230/44 kV 50/83 MVA transformers with two 230/44 kV 75/125 MVA units to accommodate the additional capacity required by the relocation of the two 44 kV feeders. This alternative will address the need to replace end-of-life transformers T1/T2/T3/T4 and associated equipment as well as associated end-of-life protection, control and telecom assets. It will allow Hydro One to standardize the DESN layout, simplify equipment maintenance and installation in case of a failure, and reliably supply the forecasted demand for the area. This refurbishment project is currently planned to be completed in 2024-2025 at a cost of $33 million.

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in Table 8-1.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

Need ID	Needs	Timing
I	Additional transformation capacity for 115kV Barrie TS	Today
II	Additional transformation capacity for the uprated 230kV Barrie TS	Long-term[10]
III	Additional transformation capacity for Parry Sound TS	Today
IV	Transmission Line Capacity for E3B/E4B	2019
V	Load restoration for loss of M6E/M7E	Today
VI	Mitigate frequency and duration of outages on the 44kV Parry Sound/Muskoka sub-region	Today
VII	Additional feeder position for InnPower supplied from Barrie TS	2020
VIII	Additional capacity required for Barrie/Innisfil Sub-Region and Barrie sub-area	Long-term
IX	Additional transformation capacity for Waubaushene TS	Long-term[11]
X	Additional transformation capacity for Everett TS	Long-term
XI	LMC and Load Security for M6E/M7E	Long-term

Projects, lead responsibility, and timeframes for implementing the wires solutions for the above needs are summarized in Table 8-2 below.

[10] The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

[11] The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacity banks have a 90% power factor and stations with low-voltage capacity banks have a 95% power factor. Since Waubaushene TS has low voltage capacity banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP.

Table 8-2 Regional Plans – Projects, Lead Responsibility, and Planned In-Service Dates

Project	Lead Responsibility	I/S Date	Cost	Need Mitigated
Replacement of 115/44 kV transformers (T1 and T2) at Barrie TS, uprating 115 kV circuits E3B/E4B to 230 kV, adding additional feeder to Barrie DESN	Hydro One	2020	$84M	I, IV, VII
Replacement of 230/44 kV transformers (T1 and T2) and possible rebuild of low voltage switchyard at Minden TS	Hydro One	2020-2021	$17M	End-of-Life
Installation of sectionalizing motorized disconnect switches on circuits M6E/M7E (at Orillia TS)	Hydro One	2021	$5-7M	V
Build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS*	Hydro One	2020	$7M	III
Replacement of 230/44 kV transformers at Parry Sound TS*	Hydro One	2021	$20M	End-of-Life, III
Replacement of Orangeville TS transformers and associated low voltage equipment, and reconfiguration of low voltage switchyards	Hydro One	2024-2025	$33M	End-of-Life

* Replacement of transformers at Parry Sound TS would eliminate the need to build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS

For the Need III, Parry Sound/Muskoka Local Achievable Potential ("LAP") study will be initiated shortly to help the Study Team better understand cost and feasibility of using distributed energy resources and local demand management options to manage the electricity demand growth in the area. Furthermore, the Study Team will need to assess the cost-benefits of the various options to address supply capacity needs at Parry Sound TS and to determine whether it would be cost-effective to advance the replacement of the companion transformers at Parry Sound TS at this time. The decision related to the end of life replacement of the transformers at Parry Sound TS will need to be made by mid-2018 so that the transformers can come into service by early 2020s.

For Need VI, cost-benefit/responsibility analysis will be considered by Hydro One Distribution, Lakeland Power and Veridian Connections to improve reliability performance of the Parry Sound/Muskoka 44 kV sub-transmission system, which will be completed by the end of 2017.

Barrie/Innisfil Sub-Region and Barrie sub-area needs (Need VIII) has been reviewed in this Regional Planning cycle and "status quo/do nothing" course of action has been recommended for the time being, while the IESO and the Study Team will continue to monitor load growth in the area and determine the conservation and demand management potential in the area.

As described in Section 7.7, no investment is required at this time to address the long-term needs II, IX, X, and XI. Further developments in the Region will be monitored and the need will be reviewed again as part of the next planning cycle.

In accordance with the Regional Planning process, the Regional Planning cycle will be triggered at least once within five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

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APPENDICES

Appendix A: Stations in the South Georgian Bay-Muskoka Region

Station (DESN)	Voltage Level	Supply Circuits
Everett TS (T1/T2)	230/44kV	E8V/E9V
Alliston TS (T2/T3/T4)	230/44kV	E8V/E9V
Midhurst TS (T1/T2)	230/44kV	M6E/M7E
Barrie TS (T1/T2)	120/44kV	E3B/E4B
Essa TS (T1/T2)	230/120kV	Essa TS 230kV supply
Parry Sound TS (T1/T2)	230/44kV	E26/E27
Waubaushene TS (T5/T6)	230/44kV	E26/E27
Muskoka TS (T1/T2)	230/44kV	M6E/M7E
Bracebridge TS (T1)	230/44kV	M6E
Orillia TS (T1/T2)	230/44kV	M6E/M7E
Beaverton TS T3/T4	230/44kV	M80B/M81B
Lindsay TS T1/T2	230/44kV	M80B/M81B
Minden TS T1/T2	230/44kV	Minden TS 230kV supply
Orangeville TS T3/T4	230/44kV	Orangeville TS 230kV supply
Orangeville TS T1/T2	230/44/28kV	Orangeville TS 230kV supply
Stayner TS T3/T4	230/44kV	Stayner TS
Wallace TS T3/T4	230/44kV	D2M/D4M
Meaford TS T1/T2	115/44kV	S2S

Appendix B: Transmission Lines in the South Georgian Bay Muskoka Region

Location	Circuit Designation	Voltage Level
Essa TS to Parry Sound/Waubaushene TS	E26/E27	230kV
Essa TS to Midhurst/Orillia/Muskoka TS	M6E/M7E	230kV
Essa TS to Alliston/Everett/Orangeville TS	E8V/E9V	230kV
Essa TS to Barrie TS	E3B/E4B	115kV
Essa TS to Stayner TS	E20S/E21S	230kV
Stayner TS to Meaford TS	S2S	115kV
Minden TS to DesJoachims TS	D1M/D2M/D3M/D4M	230kV
Minden TS to Lindsay/Beaverton TS	M80B/M81B	230kV

Appendix C: Non-Coincident Winter Load Forecast 2014-2034

Note: 2014 values in grey are actuals from IRRP

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS (T2)	Non Coincidental Gross		28.7	29.1	29.5	29.7	30.2	30.7	31.2	31.5	31.8	32.1	32.4	32.7	33.1	33.4	33.7	34.1	34.4	34.8	35.1	35.5	35.8
LTR (MVA)	CDM (MW)		0.2	0.4	0.6	0.6	0.8	1.3	1.7	1.8	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.8	4.0	4.0	4.1	4.1
S: 100	DG (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 115	Non Coincidental Net	28.6	28.5	28.7	28.9	29.1	29.4	29.4	29.5	29.7	29.7	29.8	29.9	30.1	30.2	30.3	30.4	30.5	30.6	30.8	31.1	31.4	31.7
Alliston TS (T3/T4)	Non Coincidental Gross		60.1	68.5	71.4	74.4	77.4	80.3	82.9	85.6	88.3	90.9	91.9	93.8	95.7	97.7	99.7	101.6	103.5	105.4	106.5	108.4	110.2
LTR (MVA)	CDM (MW)		0.5	0.9	1.4	1.6	2.1	3.3	4.5	5.0	5.7	6.5	7.1	7.7	8.3	9.1	9.8	10.6	11.4	12.1	12.2	12.4	12.6
S: 112	DG (MW)		0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077
W: 128	Non Coincidental Net	60.8	59.6	67.5	70.0	72.7	75.2	76.9	78.3	80.5	82.5	84.4	84.7	86.1	87.3	88.5	89.8	91.0	92.1	93.2	94.2	95.9	97.5
Barrie TS	Non Coincidental Gross		96.3	99.1	102.6	107.1	113.5	120.6	128.6	136.7	144.8	153.0	157.6	162.3	167.2	172.2	177.4	182.7	188.2	193.8	199.6	205.6	211.8
LTR (MVA)	CDM (MW)		0.7	1.3	1.9	2.3	3.1	4.9	6.9	8.0	9.4	10.9	12.2	13.3	14.5	16.0	17.4	19.0	20.7	22.2	22.9	23.6	24.3
S: 115	DG (MW)		0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027
W: 128	Non Coincidental Net	94.0	95.6	97.7	100.6	104.8	110.4	115.6	121.6	128.6	135.4	142.1	145.4	149.0	152.7	156.2	159.9	163.7	167.5	171.5	176.7	182.0	187.5
Beaverton TS	Non Coincidental Gross		96.6	97.6	98.6	98.9	100.1	101.3	102.6	103.3	103.9	104.5	105.34	106.18	107.03	107.88	108.75	109.62	110.49	111.38	112.27	113.17	114.07
LTR (MVA)	CDM (MW)		0.7	1.3	1.9	2.1	2.7	4.1	5.5	6.1	6.7	7.4	8.1	8.7	9.3	10.0	10.7	11.4	12.1	12.8	12.9	13.0	13.1
S: 204	DG (MW)		1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655
W: 224	Non Coincidental Net	92.7	94.2	94.6	95.1	95.1	95.7	95.5	95.4	95.6	95.5	95.4	95.6	95.8	96.1	96.2	96.4	96.6	96.7	96.9	97.7	98.5	99.3
Bracebridge TS	Non Coincidental Gross		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LTR (MVA)	CDM (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S: 93	DG (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 93	Non Coincidental Net	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Everett TS	Non Coincidental Gross			61.2	62.4	64.4	65.6	67.5	69.2	70.9	73.4	75.1	77.4	79.7	82.1	84.5	87.1	89.7	92.4	95.1	98.0	100.9	104.0
LTR (MVA)	CDM (MW)			0.8	1.2	1.4	1.8	2.8	3.7	4.2	4.7	5.3	6.0	6.5	7.1	7.9	8.6	9.3	10.1	10.9	11.2	11.6	11.9
S: 96	DG (MW)			0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
W: 96	Non Coincidental Net	54.7	0.0	60.4	61.2	63.0	63.8	64.7	65.4	66.7	68.6	69.7	71.4	73.1	74.9	76.6	78.5	80.3	82.2	84.2	86.7	89.3	92.0
Lindsay TS	Non Coincidental Gross		91.6	93.3	94.3	94.6	95.9	97.5	98.9	99.9	100.9	101.8	102.8	103.8	104.9	105.9	107.0	108.1	109.1	110.2	111.3	112.5	113.6
LTR (MVA)	CDM (MW)		0.7	1.3	1.8	2.0	2.6	4.0	5.3	5.9	6.5	7.2	7.9	8.5	9.1	9.9	10.5	11.2	12.0	12.6	12.8	12.9	13.0
S: 169	DG (MW)		1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634
W: 193	Non Coincidental Net	89.2	89.3	90.4	90.9	90.9	91.6	91.9	91.9	92.4	92.7	92.9	93.2	93.7	94.2	94.4	94.8	95.2	95.5	96.0	96.9	97.9	98.9
Meaford TS	Non Coincidental Gross		29.9	30.4	30.9	31.1	31.7	32.2	32.8	33.2	33.6	34.0	34.4	34.8	35.2	35.7	36.1	36.5	37.0	37.4	37.9	38.3	38.8
LTR (MVA)	CDM (MW)		0.2	0.4	0.6	0.7	0.9	1.3	1.8	1.9	2.2	2.4	2.7	2.8	3.1	3.3	3.6	3.8	4.1	4.3	4.3	4.4	4.4
S: 54	DG (MW)		0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
W: 61	Non Coincidental Net	29.7	29.7	30.0	30.3	30.4	30.8	30.9	31.0	31.2	31.4	31.6	31.8	32.0	32.2	32.3	32.5	32.7	32.9	33.1	33.5	33.9	34.3
Midhurst TS (T1/T2)	Non Coincidental Gross			108.0	110.7	113.0	115.8	119.2	131.0	133.4	136.3	139.2	141.5	144.3	147.2	149.7	154.6	157.5	160.5	163.4	166.3	169.2	172.1
LTR (MVA)	CDM (MW)			0.5	1.2	1.6	2.4	3.1	3.6	4.5	5.5	6.4	7.4	8.6	9.8	10.9	12.1	13.2	14.7	16.0	16.2	16.3	16.5
S: 172	DG (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 194	Non Coincidental Net	101.6	105.5	107.5	109.5	111.4	113.4	116.0	127.3	128.9	130.8	132.8	134.0	135.8	137.4	138.7	142.5	144.3	145.8	147.4	150.1	152.9	155.6
Midhurst TS (T3/T4)	Non Coincidental Gross			65.5	67.7	69.9	72.6	75.4	88.6	90.8	93.5	96.3	98.5	101.2	104.0	106.2	106.9	109.6	112.3	115.0	117.7	120.4	123.1
LTR (MVA)	CDM (MW)			0.3	0.7	1.0	1.6	2.3	2.6	3.2	4.0	4.7	5.6	6.5	7.6	8.7	9.5	10.4	11.7	12.8	13.1	13.2	13.5
S: 166	DG (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 192	Non Coincidental Net	75.0	63.3	65.2	67.0	68.9	71.0	73.1	86.0	87.6	89.5	91.6	92.8	94.7	96.4	97.5	97.5	99.3	100.6	102.2	104.6	107.2	109.7
Minden TS	Non Coincidental Gross			58.8	59.5	59.8	60.3	61.2	62.0	62.5	62.9	63.3	63.7	64.1	64.5	64.9	65.4	65.8	66.2	66.6	67.0	67.4	67.8
LTR (MVA)	CDM (MW)			0.2	0.4	0.5	0.7	0.9	1.0	1.2	1.4	1.5	1.6	1.8	2.0	2.1	2.3	2.5	2.7	2.8	2.8	2.8	2.8
S: 59	DG (MW)			1.630	1.630	1.630	1.630	1.630	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770
W: 64	Non Coincidental Net	55.0	56.3	57.0	57.5	57.6	58.0	58.7	59.2	59.5	59.8	60.0	60.3	60.5	60.8	61.0	61.3	61.6	61.7	62.0	62.4	62.8	63.2

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Muskoka TS	Non Coincidental Gross			160.6	163.0	164.7	166.9	169.8	172.7	175.0	177.2	179.4	181.6	183.9	186.2	188.7	191.2	193.7	196.0	198.5	201.0	203.5	205.9
LTR (MVA)	CDM (MW)			0.5	1.1	1.5	2.2	2.9	3.4	4.1	4.8	5.3	5.9	6.6	7.1	7.7	8.2	8.8	9.5	10.0	10.0	10.0	9.9
S: 154	DG (MW)			3.360	3.360	3.360	3.360	5.060	5.110	5.110	5.110	5.110	5.110	5.110	5.110	5.110	4.600	4.600	2.080	2.080	2.080	2.080	1.970
W: 175	Non Coincidental Net	165.0	167.4	156.7	158.5	159.9	161.3	161.9	164.2	165.8	167.3	169.0	170.6	172.2	174.0	175.9	178.4	180.3	184.4	186.4	188.9	191.4	194.1
Orangeville TS (T1/T2 - 27.6kV)	Non Coincidental Gross		51.4	51.9	53.1	54.2	55.4	56.6	57.8	59.0	60.0	61.0	62.1	63.2	64.4	65.5	66.7	67.9	69.1	70.4	71.6	72.9	74.2
	CDM (MW)		0.4	0.7	1.0	1.2	1.5	2.3	3.1	3.5	3.9	4.3	4.8	5.2	5.6	6.1	6.6	7.1	7.6	8.1	8.2	8.4	8.5
LTR (MVA)	DG (MW)		3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154
S: 104 W:122	Non Coincidental Net	49.3	47.9	48.1	48.9	49.9	50.7	51.1	51.5	52.4	53.0	53.5	54.2	54.9	55.6	56.3	57.0	57.7	58.4	59.1	60.3	61.4	62.6
Orangeville TS (T1/T2 - 44kV)	Non Coincidental Gross		23.4	23.9	24.3	24.6	25.1	25.6	26.1	26.6	27.0	27.4	27.8	28.2	28.7	29.1	29.5	30.0	30.4	30.9	31.3	31.8	32.3
	CDM (MW)		0.2	0.3	0.5	0.5	0.7	1.0	1.4	1.6	1.7	1.9	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.6	3.6	3.7
LTR (MVA)	DG (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S: 53 W: 63	Non Coincidental Net	24.0	23.2	23.6	23.8	24.1	24.4	24.6	24.7	25.0	25.3	25.5	25.7	25.9	26.2	26.4	26.6	26.8	27.1	27.3	27.7	28.1	28.6
Orangeville TS (T3/T4)	Non Coincidental Gross		86.2	87.7	89.3	90.3	92.2	94.1	96.1	97.6	99.1	100.5	101.9	103.3	104.8	106.2	107.7	109.2	110.8	112.3	113.9	115.5	117.1
LTR (MVA)	CDM (MW)		0.6	1.2	1.7	1.9	2.5	3.8	5.2	5.7	6.4	7.1	7.9	8.4	9.1	9.9	10.6	11.4	12.2	12.9	13.1	13.3	13.4
S: 106	DG (MW)		2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058
W: 124	Non Coincidental Net	82.6	83.5	84.5	85.5	86.3	87.6	88.2	88.9	89.8	90.6	91.3	92.0	92.8	93.6	94.3	95.1	95.8	96.6	97.4	98.8	100.2	101.6
Orillia TS	Non Coincidental Gross			127.0	128.9	131.1	133.5	136.0	138.3	139.8	141.6	143.2	144.8	146.4	148.2	149.9	151.7	153.4	155.2	156.9	158.6	160.4	162.1
LTR (MVA)	CDM (MW)			0.6	1.2	1.6	2.3	3.0	3.4	4.1	4.8	5.3	6.0	6.7	7.4	8.2	8.8	9.5	10.4	11.1	11.2	11.2	11.1
S: 165	DG (MW)			3.690	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	0.540	0.540	0.540	0.540	0.540
W: 186	Non Coincidental Net	122.4	118.3	122.7	123.5	125.3	127.0	128.8	130.6	131.5	132.6	133.6	134.6	135.5	136.5	137.5	138.7	139.7	144.2	145.2	146.9	148.7	150.5
Parry Sound TS	Non Coincidental Gross			61.2	62.1	62.7	63.4	64.5	65.5	66.3	67.1	67.9	68.6	69.4	70.2	71.1	71.9	72.8	73.6	74.5	75.3	76.2	77.1
LTR (MVA)	CDM (MW)			0.2	0.5	0.7	1.0	1.2	1.5	1.7	1.9	2.1	2.3	2.6	2.7	2.9	3.1	3.3	3.6	3.8	3.8	3.8	3.8
S: 52	DG (MW)			0.410	0.410	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	0.650	0.650	0.650	0.650	0.650
W: 57	Non Coincidental Net	57.5	60.5	60.6	61.2	61.6	62.0	62.8	63.7	64.2	64.7	65.3	65.9	66.4	67.1	67.7	68.4	69.1	70.0	70.7	71.5	72.4	73.3
Stayner TS	Non Coincidental Gross		139.4	140.6	141.9	142.2	143.8	145.6	147.3	148.3	149.3	150.2	151.1	152.0	152.9	153.8	154.8	155.7	156.6	157.6	158.5	159.5	160.4
LTR (MVA)	CDM (MW)		1.0	1.9	2.7	3.1	3.9	6.0	8.0	8.7	9.6	10.7	11.7	12.4	13.2	14.3	15.2	16.2	17.2	18.1	18.2	18.3	18.4
S: 191	DG (MW)		18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864
W: 214	Non Coincidental Net	138.3	119.5	119.9	120.3	120.3	121.0	120.8	120.5	120.7	120.8	120.7	120.6	120.7	120.8	120.7	120.7	120.6	120.6	120.6	121.5	122.3	123.1
Wallace TS	Non Coincidental Gross		40.0	40.6	41.1	41.2	41.8	42.4	42.9	43.3	43.6	43.9	44.2	44.5	44.8	45.1	45.5	45.8	46.1	46.4	46.7	47.1	47.4
LTR (MVA)	CDM (MW)		0.3	0.5	0.8	0.9	1.1	1.7	2.3	2.5	2.8	3.1	3.4	3.6	3.9	4.2	4.5	4.8	5.1	5.3	5.4	5.4	5.4
S: 55	DG (MW)		3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871
W: 60	Non Coincidental Net	39.3	35.8	36.2	36.4	36.4	36.8	36.8	36.7	36.9	36.9	36.9	36.9	37.0	37.1	37.1	37.1	37.1	37.2	37.2	37.5	37.8	38.1
Waubaushene TS	Non Coincidental Gross			99.2	99.2	100.2	101.1	102.5	103.8	104.6	105.6	106.6	107.5	108.5	109.3	110.3	111.3	112.2	113.2	114.2	115.0	115.9	116.8
LTR (MVA)	CDM (MW)			0.2	0.5	0.8	1.1	1.5	1.9	2.3	2.9	3.4	3.9	4.5	5.0	5.5	5.9	6.3	6.8	7.2	7.2	7.2	7.2
S: 100	DG (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 110	Non Coincidental Net	94.1	95.9	99.0	98.7	99.5	100.0	101.0	101.9	102.3	102.8	103.2	103.6	104.0	104.3	104.8	105.4	105.9	106.5	107.0	107.8	108.7	109.6

Appendix D: Non-Coincident Summer Load Forecast 2014-2034

Note: 2014 values in grey are actuals from IRRP

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS (T2)	Gross			38.9	42.1	45.4	48.6	51.9	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1
LTR (MVA)	CDM (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S: 100	DG (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 115	Net	28.6	33.2	38.9	42.1	45.4	48.6	51.9	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1
Alliston TS (T3/T4)	Gross			56.8	59.0	61.3	66.0	71.0	73.5	76.1	78.3	80.6	82.4	84.3	86.1	88.1	90.0	91.8	93.7	95.5	97.4	99.2	101.0
LTR (MVA)	CDM (MW)			0.4	1.2	1.4	2.1	2.7	3.3	3.9	4.5	5.1	5.7	6.5	7.0	7.8	8.5	9.1	10.0	10.7	10.8	10.8	10.8
S: 112	DG (MW)			0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222
W: 128	Net	60.8	50.3	56.1	57.7	59.6	63.7	68.0	70.0	72.0	73.6	75.3	76.5	77.6	78.9	80.0	81.3	82.4	83.5	84.6	86.4	88.2	90.0
Barrie TS	Gross			107.4	112.5	116.1	124.4	132.1	140.3	147.7	155.7	163.2	169.6	176.9	184.0	191.1	196.7	203.1	210.4	214.4	219.4	225.4	230.3
LTR (MVA)	CDM (MW)			0.5	1.2	1.9	3.2	4.5	5.4	6.6	7.8	8.9	10.6	12.1	14.1	16.5	18.1	19.9	22.2	24.2	24.5	24.6	24.8
S: 115	DG (MW)			0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041
W: 128	Net	94.0	96.8	106.9	111.2	114.2	121.1	127.5	134.9	141.1	147.8	154.2	158.9	164.8	169.9	174.6	178.6	183.1	188.2	190.1	194.8	200.7	205.5
Beaverton TS	Gross		57.2	57.6	58.2	58.1	58.8	59.5	60.3	60.7	61.1	61.4	61.7	62.0	62.3	62.6	63.0	63.3	63.6	63.9	64.2	64.5	64.9
LTR (MVA)	CDM (MW)		0.4	0.8	1.1	1.2	1.6	2.4	3.3	3.6	3.9	4.4	4.8	5.1	5.4	5.8	6.2	6.6	7.0	7.3	7.4	7.4	7.4
S: 204	DG (MW)		12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411
W: 224	Net	92.7	44.4	44.4	44.7	44.4	44.8	44.7	44.6	44.7	44.7	44.6	44.5	44.5	44.5	44.4	44.3	44.3	44.2	44.2	44.4	44.7	45.0
Bracebridge TS	Gross			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LTR (MVA)	CDM (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S: 93	DG (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 93	Net	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Everett TS	Gross		67.1	69.8	71.2	73.7	75.1	77.5	79.7	81.8	85.0	87.2	89.4	91.6	93.9	96.3	98.7	101.1	103.7	106.2	108.9	111.6	114.4
LTR (MVA)	CDM (MW)		0.5	0.9	1.4	1.6	2.1	3.2	4.3	4.8	5.5	6.2	6.9	7.5	8.1	9.0	9.7	10.5	11.4	12.2	12.5	12.8	13.1
S: 96	DG (MW)		0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211
W: 96	Net	54.7	66.4	68.7	69.6	71.9	72.8	74.1	75.2	76.8	79.3	80.8	82.3	83.9	85.6	87.1	88.7	90.4	92.1	93.8	96.2	98.6	101.1
Lindsay TS	Gross		74.3	75.4	76.2	76.1	77.1	78.5	79.7	80.5	81.2	82.0	82.7	83.5	84.2	85.0	85.8	86.5	87.3	88.1	88.9	89.7	90.5
LTR (MVA)	CDM (MW)		0.6	1.0	1.4	1.6	2.1	3.2	4.3	4.7	5.2	5.8	6.4	6.8	7.3	7.9	8.4	9.0	9.6	10.1	10.2	10.3	10.4
S: 169	DG (MW)		9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799
W: 193	Net	89.2	63.9	64.6	65.0	64.7	65.2	65.5	65.6	66.0	66.2	66.4	66.6	66.9	67.1	67.3	67.5	67.7	67.9	68.2	68.9	69.6	70.3
Meaford TS	Gross		25.5	25.9	26.2	26.4	26.8	27.3	27.8	28.2	28.5	28.9	29.2	29.5	29.8	30.1	30.4	30.7	31.0	31.3	31.6	31.9	32.2
LTR (MVA)	CDM (MW)		0.2	0.3	0.5	0.6	0.7	1.1	1.5	1.7	1.8	2.1	2.3	2.4	2.6	2.8	3.0	3.2	3.4	3.6	3.6	3.7	3.7
S: 54	DG (MW)		0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
W: 61	Net	29.7	25.3	25.5	25.7	25.8	26.1	26.2	26.3	26.5	26.6	26.8	26.9	27.1	27.2	27.3	27.4	27.5	27.6	27.7	28.0	28.3	28.5
Midhurst TS (T1/T2)	Gross			109.8	112.5	114.8	118.4	121.4	124.2	126.8	130.3	132.8	135.4	138.9	141.5	144.0	147.7	150.2	153.8	156.4	159.9	162.5	166.0
LTR (MVA)	CDM (MW)			0.7	1.6	2.2	3.3	4.4	5.1	6.1	7.3	8.3	9.5	10.9	12.1	13.4	14.7	15.8	17.5	18.7	19.0	19.1	19.4
S: 172	DG (MW)			2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786
W: 194	Net	101.6	99.9	106.3	108.1	109.8	112.3	114.2	116.4	117.9	120.2	121.7	123.1	125.3	126.6	127.9	130.2	131.7	133.5	134.9	138.1	140.5	143.8
Midhurst TS (T3/T4)	Gross			72.0	75.0	78.0	80.0	83.0	86.0	89.0	91.0	94.0	97.0	100.0	103.0	105.0	108.0	111.0	115.0	118.0	121.0	124.0	127.0
LTR (MVA)	CDM (MW)			0.2	0.6	0.9	1.6	2.3	2.6	3.3	4.4	5.4	6.6	7.8	9.3	10.8	12.1	13.5	15.5	17.2	17.5	17.6	17.9
S: 166	DG (MW)			0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031
W: 192	Net	75.0	65.0	71.7	74.3	77.1	78.4	80.7	83.4	85.6	86.6	88.6	90.4	92.2	93.6	94.2	95.8	97.4	99.5	100.8	103.5	106.3	109.0
Minden TS	Gross			25.4	25.6	25.8	26.0	26.4	26.8	27.0	27.2	27.4	27.5	27.7	27.9	28.1	28.3	28.5	28.7	28.9	29.0	29.2	29.4
LTR (MVA)	CDM (MW)			0.2	0.3	0.4	0.6	0.7	0.8	1.1	1.3	1.5	1.7	1.9	2.2	2.4	2.6	2.9	3.2	3.4	3.4	3.4	3.4
S: 59	DG (MW)			1.660	1.660	2.210	2.330	2.940	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.050
W: 64	Net	55.0	24.3	23.6	23.6	23.2	23.1	22.7	22.9	22.8	22.8	22.9	22.7	22.7	22.7	22.6	22.6	22.6	22.5	22.5	22.6	22.7	23.0

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Muskoka TS	Gross			93.5	94.7	95.4	96.3	98.0	99.5	100.6	101.5	102.5	103.5	104.3	105.4	106.5	107.5	108.7	109.6	110.6	111.5	112.5	113.6
LTR (MVA)	CDM (MW)			0.7	1.4	1.9	2.8	3.6	4.3	5.1	6.0	6.7	7.4	8.2	8.9	9.6	10.2	11.0	12.0	12.6	12.6	12.6	12.4
S: 154	DG (MW)			7.970	8.070	8.290	8.620	13.400	13.450	13.450	13.450	13.450	13.450	13.450	13.450	13.450	12.940	12.940	10.420	10.410	10.410	8.150	5.810
W: 175	Net	165.0	97.2	84.9	85.2	85.2	84.9	81.0	81.8	82.0	82.1	82.4	82.7	82.6	83.1	83.5	84.3	84.8	87.2	87.6	88.5	91.8	95.4
Orangeville TS	Gross		53.1	56.1	57.4	58.4	59.5	60.8	62.1	63.2	64.2	65.2	66.2	67.2	68.2	69.2	70.2	71.3	72.4	73.4	74.5	75.7	76.8
(T1/T2 - 27.6kV)	CDM (MW)		0.4	0.8	1.1	1.3	1.6	2.5	3.4	3.7	4.1	4.6	5.1	5.5	5.9	6.4	6.9	7.4	7.9	8.4	8.6	8.7	8.8
LTR (MVA)	DG (MW)		1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519
S: 104 W: 122	Net	49.3	51.2	53.8	54.8	55.6	56.4	56.8	57.2	58.0	58.5	59.1	59.6	60.2	60.8	61.2	61.8	62.4	62.9	63.5	64.5	65.5	66.5
Orangeville TS	Gross		24.2	24.5	25.0	25.1	25.6	26.2	26.8	27.2	27.6	28.0	28.4	28.8	29.2	29.6	30.0	30.4	30.9	31.3	31.7	32.2	32.6
(T1/T2 - 44kV)	CDM (MW)		0.2	0.3	0.5	0.5	0.7	1.1	1.4	1.6	1.8	2.0	2.2	2.4	2.5	2.8	3.0	3.2	3.4	3.6	3.6	3.7	3.7
LTR (MVA)	DG (MW)		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
S: 53 W: 63	Net	24.0	24.0	24.2	24.5	24.6	24.9	25.1	25.3	25.6	25.8	26.0	26.2	26.4	26.7	26.8	27.1	27.3	27.5	27.7	28.1	28.5	28.9
Orangeville TS (T3/T4)	Gross		67.4	68.4	69.6	70.2	71.5	73.1	74.6	75.8	77.0	78.1	79.2	80.3	81.4	82.6	83.7	84.9	86.1	87.3	88.5	89.7	91.0
	CDM (MW)		0.5	0.9	1.3	1.5	2.0	3.0	4.0	4.4	5.0	5.5	6.1	6.6	7.1	7.7	8.2	8.8	9.4	10.0	10.2	10.3	10.4
LTR (MVA)	DG (MW)		1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071
S 106 W: 124	Net	82.6	65.8	66.4	67.2	67.6	68.5	69.0	69.5	70.3	71.0	71.5	72.0	72.7	73.3	73.8	74.4	75.0	75.6	76.2	77.3	78.4	79.5
Orillia TS	Gross			99.8	101.2	103.2	105.2	107.2	109.0	110.3	111.6	112.9	114.2	115.4	116.8	118.1	119.6	120.9	122.2	123.7	125.0	126.4	127.7
LTR (MVA)	CDM (MW)			0.6	1.3	1.7	2.5	3.3	3.8	4.7	5.5	6.2	7.0	7.9	8.8	9.7	10.5	11.3	12.5	13.4	13.4	13.4	13.3
S: 165	DG (MW)			10.620	11.240	11.350	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	7.770	7.710	7.650	7.510	1.410
W: 186	Net	122.4	84.9	88.5	88.6	90.1	91.2	92.4	93.7	94.2	94.7	95.3	95.7	96.1	96.6	96.9	97.6	98.1	101.9	102.6	104.0	105.5	113.0
Parry Sound TS	Gross			31.3	31.8	32.1	32.5	33.0	33.6	34.0	34.4	34.8	35.1	35.6	36.0	36.4	36.9	37.3	37.8	38.2	38.7	39.1	39.6
LTR (MVA)	CDM (MW)			0.2	0.5	0.6	0.9	1.1	1.3	1.7	2.0	2.2	2.5	2.8	3.0	3.3	3.6	3.9	4.3	4.5	4.6	4.6	4.5
S: 52	DG (MW)			0.460	0.490	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	0.730	0.730	0.730	0.730	0.730
W: 57	Net	57.5	30.9	30.6	30.9	30.4	30.5	30.7	31.1	31.2	31.3	31.5	31.5	31.7	31.8	31.9	32.2	32.3	32.8	32.9	33.4	33.8	34.3
Stayner TS	Gross		104.6	105.2	106.1	105.9	106.9	108.3	109.7	110.5	111.2	111.9	112.6	113.2	113.9	114.6	115.3	116.0	116.7	117.4	118.1	118.8	119.5
LTR (MVA)	CDM (MW)		0.8	1.4	2.0	2.3	2.9	4.4	5.9	6.5	7.2	7.9	8.7	9.3	9.9	10.7	11.3	12.1	12.8	13.5	13.5	13.6	13.7
S: 191	DG (MW)		8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735
W: 214	Net	138.3	95.1	95.1	95.3	94.9	95.2	95.1	95.0	95.3	95.3	95.2	95.1	95.3	95.3	95.2	95.2	95.2	95.1	95.2	95.8	96.4	97.1
Wallace TS	Gross		36.0	36.4	36.8	36.9	37.3	37.8	38.4	38.7	39.0	39.3	39.6	39.9	40.1	40.4	40.7	41.0	41.3	41.6	41.8	42.1	42.4
LTR (MVA)	CDM (MW)		0.3	0.5	0.7	0.8	1.0	1.5	2.1	2.3	2.5	2.8	3.1	3.3	3.5	3.8	4.0	4.3	4.5	4.8	4.8	4.8	4.9
S: 55	DG (MW)		3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880
W: 60	Net	39.3	31.9	32.0	32.2	32.2	32.4	32.4	32.4	32.5	32.6	32.6	32.6	32.7	32.8	32.8	32.8	32.8	32.9	32.9	33.2	33.4	33.7
Waubaushene TS	Gross			75.1	75.5	76.1	76.9	77.7	78.5	79.2	80.8	81.5	82.1	82.7	83.4	84.0	84.7	85.4	86.1	87.8	88.3	88.9	89.5
LTR (MVA)	CDM (MW)			0.2	0.5	0.7	1.0	1.3	1.5	2.1	2.8	3.4	4.2	5.0	5.7	6.3	7.0	7.6	8.3	8.9	8.9	9.0	9.0
S: 100	DG (MW)			9.360	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.300	4.570	2.240
W: 110	Net	94.1	71.6	65.5	65.6	66.0	66.5	67.0	67.6	67.7	68.6	68.7	68.5	68.3	68.3	68.3	68.3	68.4	68.4	69.5	70.1	75.4	78.3

Appendix E: List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code

UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Hydro One Network Inc.
483 Bay Street
6th Floor, South Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345.5420
ajay.garg@HydroOne.com

Sudbury/Algoma Region

Regional Infrastructure Plan ("RIP")

June 10th, 2016

Greater Sudbury Hydro Inc.
Hydro One Networks Inc. (Distribution)

The Sudbury to Algoma Region includes Greater Sudbury Area, Manitoulin Island, and townships of Verner, Warren, Elliot Lake, Blind River and Walden.

The Needs Assessment ("NA") for the Sudbury/Algoma region was completed in March, 2015 (see attached) and the report recommends that no further coordinated regional planning is required to address needs in the Sudbury-Algoma Region.

To address local needs, local planning was undertaken by Hydro One Networks Inc. (Transmitter) and Hydro One Networks Inc. (Distribution) to address the "Manitoulin TS Low Voltage Regulation" need. A Local Planning ("LP") report was prepared and published by the Working Group for the Sudbury/Algoma region in September, 2015 (also attached).

The only major project planned for the Sudbury/Algoma Region over the near and mid-term is

- New 230/44kV station at Hanmer Ts to replace Coniston Ts (115/22kV). As part of this project, Coniston loads will be converted from 22kV to 44kV (2019). The approximate cost of this work is $25M. This is a pool funded investment.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the ("RIP") for the Sudbury/Algoma Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2013) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at www.ontarioenergyboard.ca

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

LOCAL PLANNING REPORT

Manitoulin TS Low Voltage Regulation
Region: Sudbury-Algoma

Revision: Final
Date: September 30, 2015

Prepared by: Hydro One Networks Inc (Transmission & Distribution)

Study Team	
Organization	Name
Hydro One Networks Inc. (Lead Transmitter)	Kirpal Bahra
Hydro One Networks Inc. (Distribution)	Richard Shannon

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Sudbury-Algoma Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Local Planning Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Sudbury to Algoma (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 20, 2014	**END DATE**	September 30, 2015

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only options and recommend a preferred solution that will address the local needs identified in the Needs Assessment (NA) report for the Sudbury-Algoma Region dated March 12, 2015. The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

Based on Section 6 of the NA report, the study team recommended that no further coordinated regional planning is required to address the needs in the Sudbury-Algoma region. These needs are local in nature and will be addressed by wires options through local planning led by Hydro One with participation of the impacted LDC.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

The Manitoulin TS Voltage Regulation is a local need addressed in this report.

3. OPTIONS CONSIDERED

Hydro One (Transmitter) and Hydro One Distribution (LDC) have considered addressing the above need with the following options;

Alternative 0 – Status Quo.
Alternative 1 - Install 44kV Capacitor Bank at Manitoulin TS
Alternative 2 - Install 115kV Capacitor Bank at Manitoulin TS

See Section 3 for further detail.

4. PREFERRED SOLUTION

The preferred solution at this time is Alternative 0 – Status Quo. See Section 4 for details.

5. NEXT STEPS

The next steps are summarized in section 5

Table of Contents

1 INTRODUCTION

The Needs Assessment (NA) for the Sudbury/Algoma ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. Prior to the new regional planning process coming into effect, planning activities were already underway in the Region to address some specific station capacity needs. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Sudbury-Algoma Region over the next ten years (2014 to 2023) and recommended whether they should be further assessed through the transmitter-led Local Planning (LP) process or the IESO-led Scoping Assessment (SA) process.

1.1 Sudbury to Algoma Region Description and Connection Configuration

The Sudbury to Algoma Region includes Greater Sudbury Area, Manitoulin Island, and townships of Verner, Warren, Elliot Lake, Blind River and Walden. The boundaries of the Sudbury to Algoma Region are shown below in Figure 1.

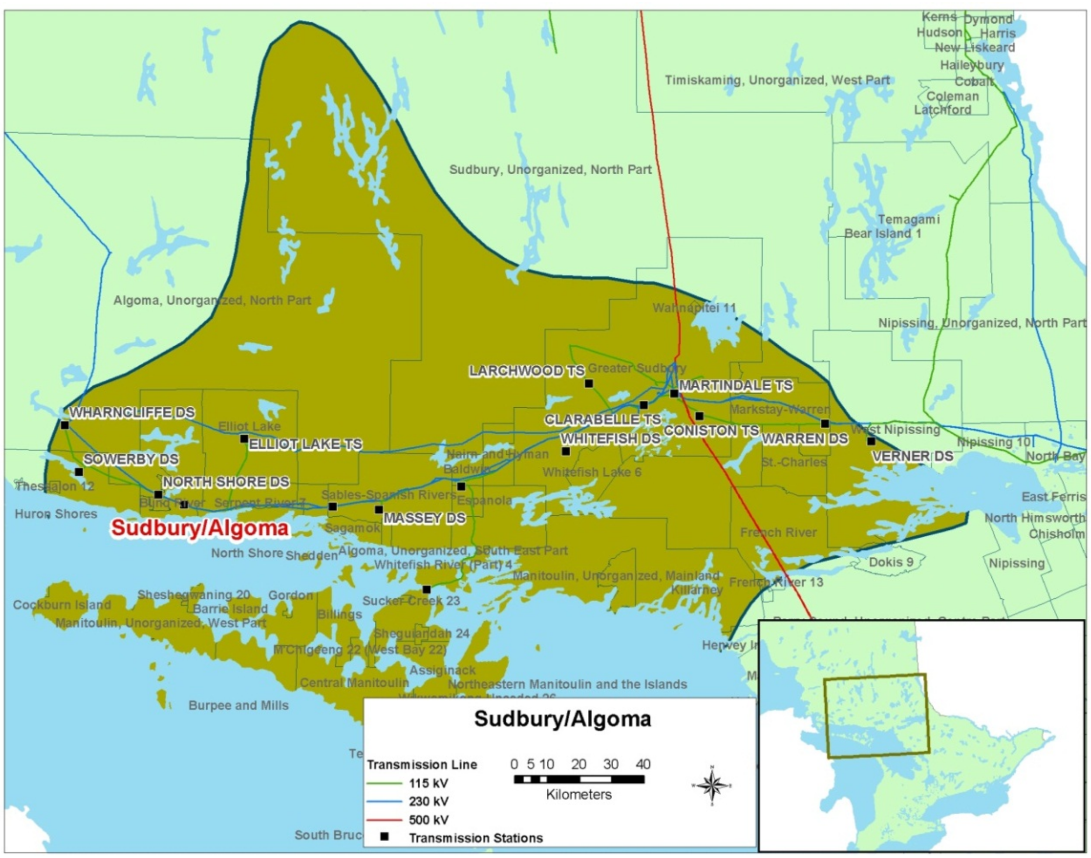

Figure 1: Sudbury to Algoma Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied by autotransformers at Hanmer TS, Algoma TS and Martindale TS. This area is further reinforced through the 500kV circuits (P502X and X504/503E) connecting Hanmer TS (Sudbury) to both Porcupine TS (Timmins) and Essa TS (Barrie). It is also connected to Northwest Ontario through Mississagi TS. Table 2 below lists the major transmission circuits and Hydro One stations in the subject region.

This region has the following two local distribution companies (LDC):

- Greater Sudbury Hydro Inc.
- Hydro One Networks Inc. (Distribution)

Espanola Regional Hydro Distribution is a third LDC in this region embedded into the Hydro One Distribution system. Although invited, this LDC opted not to participate in the Study Team. However, the interests of this LDC were communicated and considered through Hydro One Distribution as a host LDC.

Transmission connected loads in the Sudbury to Algoma region form a large percentage (approximately 50%) of the overall demand. Although these customers are not explicitly participating in the regional planning process, Hydro One considered their impact in this analysis.

115kV circuits	230kV circuits	Hydro One Transformer Stations
S6F,S5M	X74P, X27A	ALGOMA TS
S2B,B4B	A23P, A24P	MARTINDALE TS
T1B, B3E	X23N, S21N	HANMER TS
B4E, L1S	X25S, X26S	CONISTON TS
	S22A	CLARABELLE TS
		ELLIOT LAKE TS
		ESPANOLA TS
		LARCHWOOD TS
		MANITOULIN TS

Table 1: Transmission Lines and Stations in Sudbury to Algoma Region

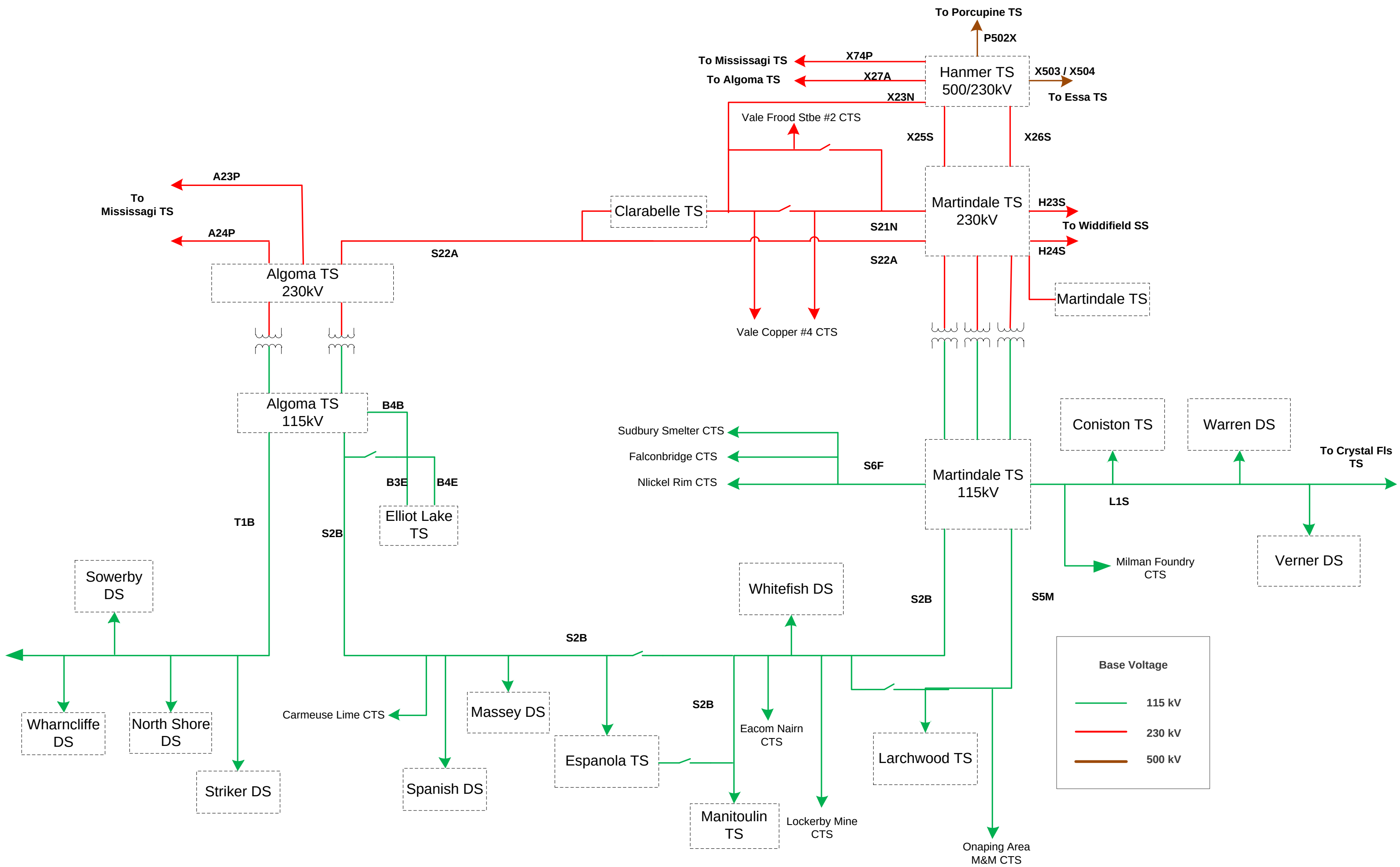

Figure 2: Single Line Diagram – Sudbury to Algoma Region

2 AREA NEEDS

2.1 Sudbury-Algoma Region Needs

As an outcome of the NA process, the study team did not identify any capacity needs based on LDCs load forecast. Only need identified was an issue with potential voltage regulation at Manitoulin TS in the Sudbury-Algoma Region to be addressed by a “localized” wires planning. Where local planning was recommended to address the needs, Hydro One, as transmitter, with the impacted LDC, further undertook planning assessments to address the need.

2.2 Needs Assessed by Hydro One led Local Planning

- Manitoulin TS Voltage Regulation – pre-contingency voltages at Manitoulin TS 115kV can at times fall below the ORTAC criteria of 113kV. Without McLean’s mountain wind farm in service, and under peak load conditions, pre-contingency voltage at Manitoulin TS high voltage bus can be as low as 110kV when supplied from Algoma TS, and 112kV when supplied from Martindale TS.

3 ALTERNATIVES CONSIDERED

Hydro One transmission reviewed the above need and determined that the only LDC impacted by a low voltage at Manitoulin TS is Hydro One distribution which is directly supplied at the stations’ 44kV bus. Following options were considered to address the needs identified in section 2 above.

Alternative 1 – Status Quo.

No further action is required at this time. Hydro One and LDC will monitor the load and voltages over the next three years. Further review will be undertaken in the next planning cycle or earlier if there is any evidence where load cannot be served or system cannot be operated in a safe, secure and reliable manner.

Alternative 2 – Install 44kV Capacitor Bank at Manitoulin TS

A 7MX low voltage capacitor bank can help improve high voltages regulation at Manitoulin TS. Manitoulin TS has a non-standard low voltage switch yard arrangement whereby each of the two feeders is supplied from a dedicated bus and associated transformer. There is currently no tie breaker between the two 44kV buses and thus, two 5.4MX capacitor banks will be required (for each of the busses). See figure 3.

Alternative 3 – Install 115kV Capacitor Bank at Manitoulin TS

A high voltage capacitor bank would also regulate the high voltage bus at Manitoulin TS. This alternative would require two high voltage breakers, and a motorized disconnect switch. See figure 4. Further investigation into this alternative indicated that 96MX capacitor bank is the smallest size available at this voltage. This large capacitor size would cause large voltage changes during switching and would violate operational criteria. Although this aspect would rule out this alternative it is shown illustration purposes in Table 3.

Table 3 below provides a budgetary cost summary of a cost of all options.

Options Considered	Cost
Alternative 1 – Hydro One to assess voltage performance of 115kV and 44kV bus with no immediate investment.	--
Alternative 2 – Install 44kV Capacitor Bank at Manitoulin TS	$4M
Alternative 3 – Install 115kV Capacitor Bank at Manitoulin TS	$6M

Table 2 – Budgetary Cost for Alternatives

4 PREFERRED SOLUTION AND REASONING

Hydro One Networks and the LDC have reviewed all alternatives and the preferred solution at this time is, Alternative 1 – Status Quo.

The study team acknowledges that the Manitoulin TS HV bus may experience voltages below ORTAC requirements only during limited operating scenarios. These scenarios are infrequent and the impacts of a low voltage at this point does not affect system stability or result in low voltages issues beyond the Manitoulin TS and Hydro One Distribution (LDC)

Manitoulin TS power transformers (T3/T4) are presently equipped with under load tap changers which have the ability to maintain 44kV bus voltages for wide array of voltage variations on the 115kV bus. ULTC ratings for both T3 and T4 are 44kV +/- 20% on 115.5kV at 42MVA load. These ratings are sufficient to maintain a customer delivery point performance within the rules of the Transmission System Code. The 44kV bus voltage will be maintained within 1.06 and 0.98pu for a 110kV (or lower) voltage.

Manitoulin TS voltage is constantly monitored by Hydro One's Ontario Grid Control Centre (OGCC) . OGCC's records will be reviewed regularly to ascertain the system conditions during peak load and its ability to operate the system and supply load to Manitoulin TS at acceptable voltage.

Voltage history will be reviewed with the LDC to determine if 44kV supply voltage remains within acceptable range for all distributed connected customers. The next planning cycle will take place within five years and an investment can be triggered at any time should there be a situation where load cannot be served or system cannot be operated safely and reliably.

5 NEXT STEPS

A summary of the next steps, actions/solutions and timelines required to address the local needs are as follows:

Need	Action / Recommended Solution	Lead Responsibility	Timeframe
Low Voltage at Manitoulin 115kV bus	• Status Quo –standard five year cycle	Hydro One Networks	Maximum five years

Table 3: Solutions and Timeframe

6 DIAGRAMS

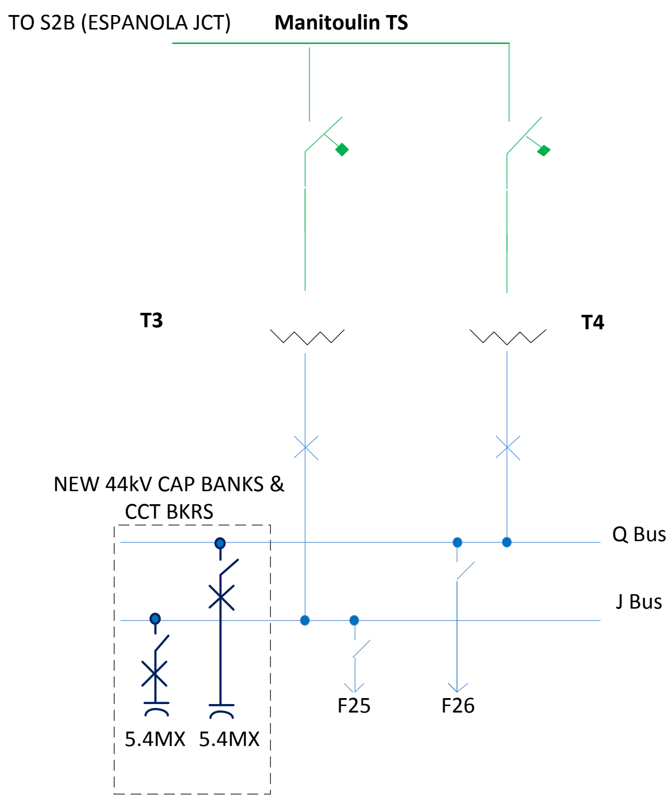

Figure 3 – New 44kV Capacitor Banks

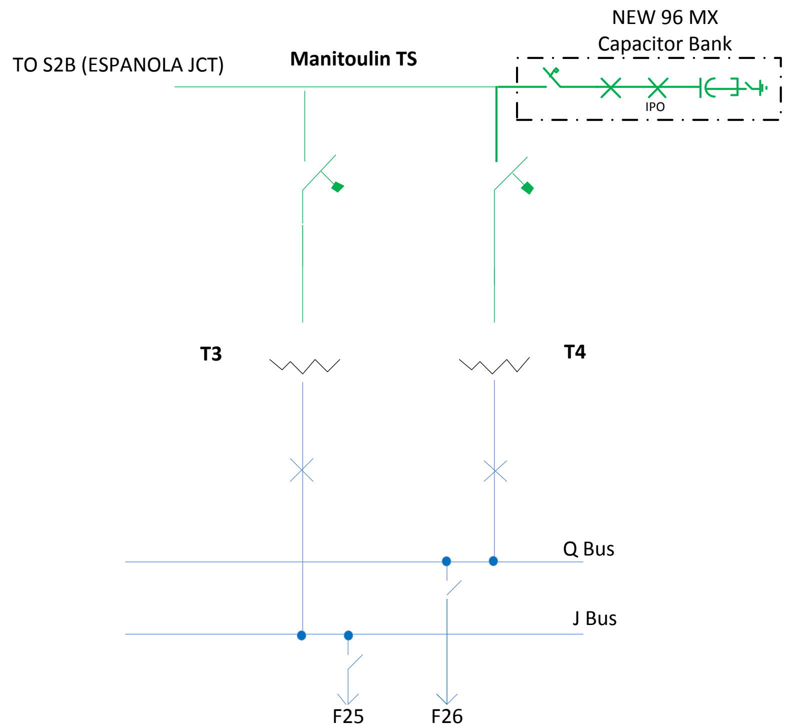

Figure 4 – 115kV Cap bank

7 REFERENCES

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

[3] Sudbury-Algoma Needs Assessment Report

8 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Planning
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

APPENDIX A – LOAD FORECAST FOR SUDBURY-ALGOMA STATIONS

Station Name	DESN ID	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
			2011	2012	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Clarabelle TS	T1/T2	Gross Peak Load				106.7	105.8	104.9	103.9	103.0	102.1	101.3	100.4	99.5	98.6
		Net Load Forecast	87.4	78.7	114.3										
Coniston TS	T2/T3	Gross Peak Load				3.6	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.8
		Net Load Forecast	9.0	10.8	7.1										
Elliot Lake TS	T1/T2/T3	Gross Peak Load				20.3	20.4	20.6	20.7	20.7	20.9	21.1	21.2	21.3	21.4
		Net Load Forecast	43.2	39.3	40.3										
Espanola TS	T1/T2/T3	Gross Peak Load				13.9	14.0	14.0	14.1	14.2	14.3	14.5	14.5	14.6	14.6
		Net Load Forecast	26.7	24.0	26.4										
Larchwood TS	T2	Gross Peak Load				13.2	13.3	13.4	13.5	13.6	13.8	13.9	14.0	14.1	14.2
		Net Load Forecast	25.2	27.1	26.2										
Manitoulin TS	T3/T4	Gross Peak Load				37.8	38.2	38.5	38.8	39.0	39.5	40.0	40.3	40.5	40.8
		Net Load Forecast	73.5	63.5	71.0										
Martindale TS	T25/T26	Gross Peak Load				149.5	151.5	152.3	153.0	153.6	154.5	155.3	155.9	156.5	157.9
		Net Load Forecast	97.7	88.3	95.0										
Massey DS	T1	Gross Peak Load				7.5	7.6	7.6	7.7	7.7	7.8	7.9	8.0	8.0	8.1
		Net Load Forecast	11.7	10.7	14.9										
North Shore DS	T1	Gross Peak Load				5.9	6.0	6.1	6.1	6.2	6.3	6.5	6.5	6.6	6.7
		Net Load Forecast	11.3	11.5	11.5										

LOAD FORECAST FOR SUDBURY-ALGOMA REGION (CONTINUED)

Station Name	DESN ID	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sowerby DS	T1	Gross Peak Load				4.7	4.7	4.8	4.8	4.8	4.8	4.9	4.9	4.9	5.0
		Net Load Forecast	10.3	9.7	9.3										
Spanish DS	T1	Gross Peak Load				4.0	4.1	4.1	4.2	4.3	4.3	4.4	4.5	4.6	4.6
		Net Load Forecast	7.7	6.7	7.9										
Striker DS	T1/T2	Gross Peak Load				10.0	10.1	10.3	10.4	10.5	10.7	10.8	11.0	11.1	11.2
		Net Load Forecast	16.8	14.0	19.6										
Verner DS	T1/T2	Gross Peak Load				6.3	6.4	6.4	6.5	6.5	6.6	6.7	6.7	6.8	6.8
		Net Load Forecast	12.1	10.8	12.5										
Warren DS	T1/T2	Gross Peak Load				8.0	8.1	8.1	8.2	8.2	8.3	8.4	8.5	8.5	8.6
		Net Load Forecast	14.6	13.0	15.5										
Wharncliffe DS	T1/T2	Gross Peak Load				5.3	5.3	5.3	5.4	5.4	5.4	5.5	5.5	5.5	5.6
		Net Load Forecast	9.9	9.1	10.5										
Whitefish DS	T1	Gross Peak Load				6.6	6.7	6.7	6.8	6.8	6.9	7.0	7.0	7.1	7.1
		Net Load Forecast	13.8	12.1	13.1										

1. CDM & DG Not included in this table.
2. Sudbury-Algoma region is winter peaking

DG & CDM Forecast for Sudbury-Algoma Stations

Station Name	DESN ID	BUS ID	Customer Data	Existing	Near Term Forecast					Medium Term Forecast				
				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Clarabelle TS	T1/T2	M1/M3/M7	DG (MW)	5.93	6.19	6.20	6.21	6.21	6.21	6.21	6.21	6.21	6.21	6.21
			CDM	-	-	-	-	-	-	-	-	-	-	-
Coniston TS	T2/T3	M1	DG (MW)	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
			CDM	-	-	-	-	-	-	-	-	-	-	-
Elliot Lake TS	T1/T2/T3	M1/M2/M3	DG (MW)	-	0	0	0	0	0	8.46	8.46	8.46	8.46	8.46
			CDM	-	-	-	-	-	-	-	-	-	-	-
Espanola TS	T1/T2/T3	M1	DG (MW)	-	-	-	-	-	-	2.54	2.54	2.54	2.54	2.54
			CDM	-	-	-	-	-	-	-	-	-	-	-
Larchwood TS	T2	M3/M4	DG (MW)	-	-	-	-	-	-	6.28	6.28	6.28	6.28	6.28
			CDM	-	-	-	-	-	-	-	-	-	-	-
Manitoulin TS	T3/T4	M25/M26	DG (MW)	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88
			CDM	-	-	-	-	-	-	-	-	-	-	-
Martindale TS	T25/T26	M5/M6/M7	DG (MW)	5.98	5.98	6.40	6.40	6.40	6.40	8.49	8.49	8.49	8.49	8.49
			CDM	-	-	-	-	-	-	-	-	-	-	-
Massey DS	T1	F1/F3	DG (MW)		-	-	-	-	-					
			CDM	-	-	-	-	-	-	-	-	-	-	-
North Shore DS	T1	F1/F2	DG (MW)	1.71	1.71	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94
			CDM	-	-	-	-	-	-	-	-	-	-	-

DG & CDM Forecast for Sudbury-Algoma Stations (Continued)

Station Name	DESN ID	BUS ID	Customer Data	Existing	Near Term Forecast					Medium Term Forecast				
				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sowerby DS	T1	F1/F2	DG (MW)	-	-	-	-	-	-	-	-	-	-	-
			CDM	-	-	-	-	-	-	-	-	-	-	-
Spanish DS	T1	F1/F2	DG (MW)	-	-	-	-	-	-	0.78	0.78	0.78	0.78	0.78
			CDM	-	-	-	-	-	-	-	-	-	-	-
Striker DS	T1/T2	F1/F2	DG (MW)	0.01	0.01	0.01	0.01	0.01	0.08	0.08	0.08	0.08	0.08	0.08
			CDM	-	-	-	-	-	-	-	-	-	-	-
Verner DS	T1/T2	F1/F2/F3	DG (MW)											
			CDM	-	-	-	0	0	0	0	0	0	0	0
Warren DS	T1/T2	F1/F2/F3/F4	DG (MW)	-	-	-	0	0	0.02	0.02	0.02	0.02	0.02	0.02
			CDM	-	-	-	-	-	-	-	-	-	-	-
Wharncliffe DS	T1/T2	F1/F2	DG (MW)	-	-	-	-	-	-	-	0.47	0.47	0.47	0.47
			CDM	-	-	-	-	-	-	-	-	-	-	-
Whitefish DS	T1	F1/F2/F3	DG (MW)	-	-	-	-	0.02	0.02	0.02	0.02	0.02	0.02	0.02
			CDM	-	-	-	-	-	-	-	-	-	-	-

1. DG value (MW) is cumulative
2. DG MW Value is for winter peak
3. '-' indicates CDM or DG value not available

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: Sudbury Algoma

Date: March 12, 2015

Prepared by: Sudbury - Algoma Region Study Team

Greater Sudbury Hydro Inc
Hydro du Grand Sudbury Inc

Sudbury to Algoma Region Study Team	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Kirpal Bahra
Independent Electricity System Operator	Phillip Woo Angelina Tan Kun Xiong
Greater Sudbury Hydro	Brian McMillan
Hydro One Networks Inc. (Distribution)	Richard Shannon

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Sudbury Algoma region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Sudbury to Algoma (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 20, 2014	**END DATE**	March 20, 2015

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Sudbury to Algoma Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the Sudbury Algoma Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Sudbury Algoma Region belongs to Group 2. The NA for this Region was triggered on October 20, 2014 and was completed on March 20, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to the next 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2023. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the Sudbury Algoma Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2014 to 2023). The assessment reviewed available information and load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. 230/115 kV Autotransformers

- The 230/115 kV autotransformers (Algoma TS, Martindale TS, Hanmer TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

C. 115kV Transmission Lines

- The 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region.
-

D. 230 kV and 115 kV Connection Facilities

- The 230k and 115kV connection facilities in this region are adequate over the study period.

E. Pre-contingency voltages at Manitoulin TS

- Under peak load conditions, pre-contingency voltages at Manitoulin TS 115kV bus can be below 113 kV.

System Reliability, Operation and Restoration Review

Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period. For the loss of one or two elements, the load interrupted by configuration does not exceed 150 MW or 250 MW. In addition,

- As identified by the IESO, under peak load conditions, the loss of two Martindale TS 230/115kV transformers may result in the overload of the third Martindale transformer.
- As identified by the IESO, With either X25S or X26S is out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable ORTAC limits.

The above issues will be further assessed as part of bulk system planning outside of the regional planning process.

Aging Infrastructure / Replacement Plan

Replacement of the autotransformers at Martindale is currently in Hydro One's 5yr sustainment business plan. As part of this replacement, T21/T23 autotransformer replacement at Martindale TS may result in higher emergency ratings.

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that no further regional coordination is required and following needs identified in Section 6 be further assessed as part of Local Planning:

Manitoulin TS Voltage Regulation

- Low pre-contingency voltages at Manitoulin TS 115kV bus.

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LIST OF FIGURES

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Sudbury to Algoma Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the Sudbury to Algoma Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. If localized wires only solutions do not require further coordinated regional planning, the SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by the Sudbury to Algoma Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Sudbury to Algoma Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Greater Sudbury Hydro Inc ("Sudbury Hydro")
4.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the Sudbury to Algoma Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Sudbury to Algoma Region belongs to Group 2. The NA for this Region was triggered on October 20, 2014 and was completed on March 20, 2015

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the Sudbury to Algoma Region over an assessment period of 2014 to 2023. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 Sudbury to Algoma Region Description and Connection Configuration

The Sudbury to Algoma Region includes Greater Sudbury Area, Manitoulin Island, and townships of Verner, Warren, Elliot Lake, Blind River and Walden. The boundaries of the Sudbury to Algoma Region are shown below in Figure 1.

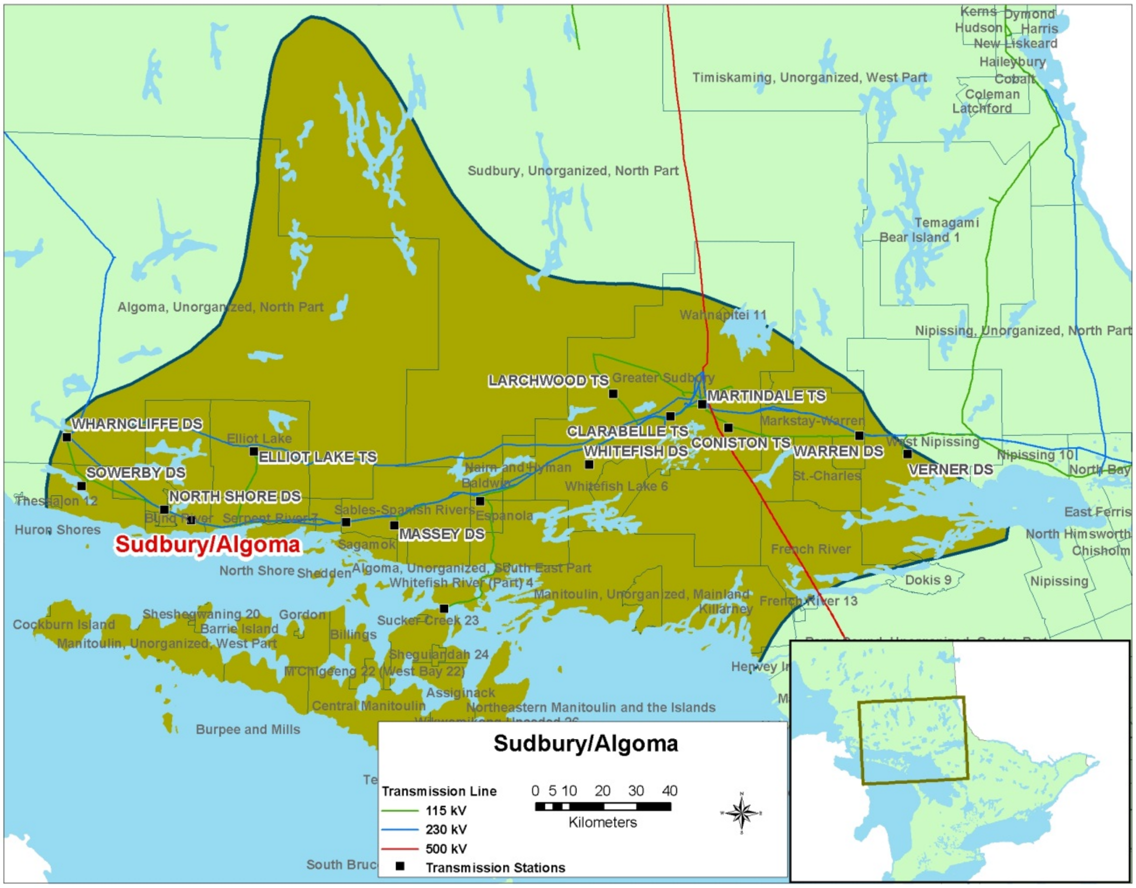

Figure 1: Sudbury to Algoma Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied by autotransformers at Hanmer TS, Algoma TS and Martindale TS. This area is further reinforced through the 500kV circuits (P502X and X504/503E) connecting Hanmer TS (Sudbury) to both Porcupine TS (Timmins) and Essa TS (Barrie). It is also connected to Northwest Ontario through Mississagi TS. Table 2 below lists the major transmission circuits and Hydro One stations in the subject region.

This region has the following two local distribution companies (LDC):

- Greater Sudbury Hydro Inc.
- Hydro One Networks Inc. (Distribution)

Espanola Regional Hydro Distribution is a third LDC in this region embedded into the Hydro One Disribution system. Although invited to participate in the Study Team, the interests of this LDC was communicated through Hydro One Distribution.

Tranmission connected loads in the Sudbury to Algoma region form a large percentage (approximately 50%) of the overall demand. Although these customers are not explicitly participating in the regional planning process, Hydro One will consider their impact in the NA of this region.

115kV circuits	230kV circuits	Hydro One Transformer Stations
S6F,S5M	X74P, X27A	ALGOMA TS
S2B,B4B	A23P, A24P	MARTINDALE TS
T1B, B3E	X23N, S21N	HANMER TS
B4E, L1S	X25S, X26S	CONISTON TS
	S22A	CLARABELLE TS
		ELLIOT LAKE TS
		ESPANOLA TS
		LARCHWOOD TS
		MANITOULIN TS

Table 2: Transmission Lines and Stations in Sudbury to Algoma Region

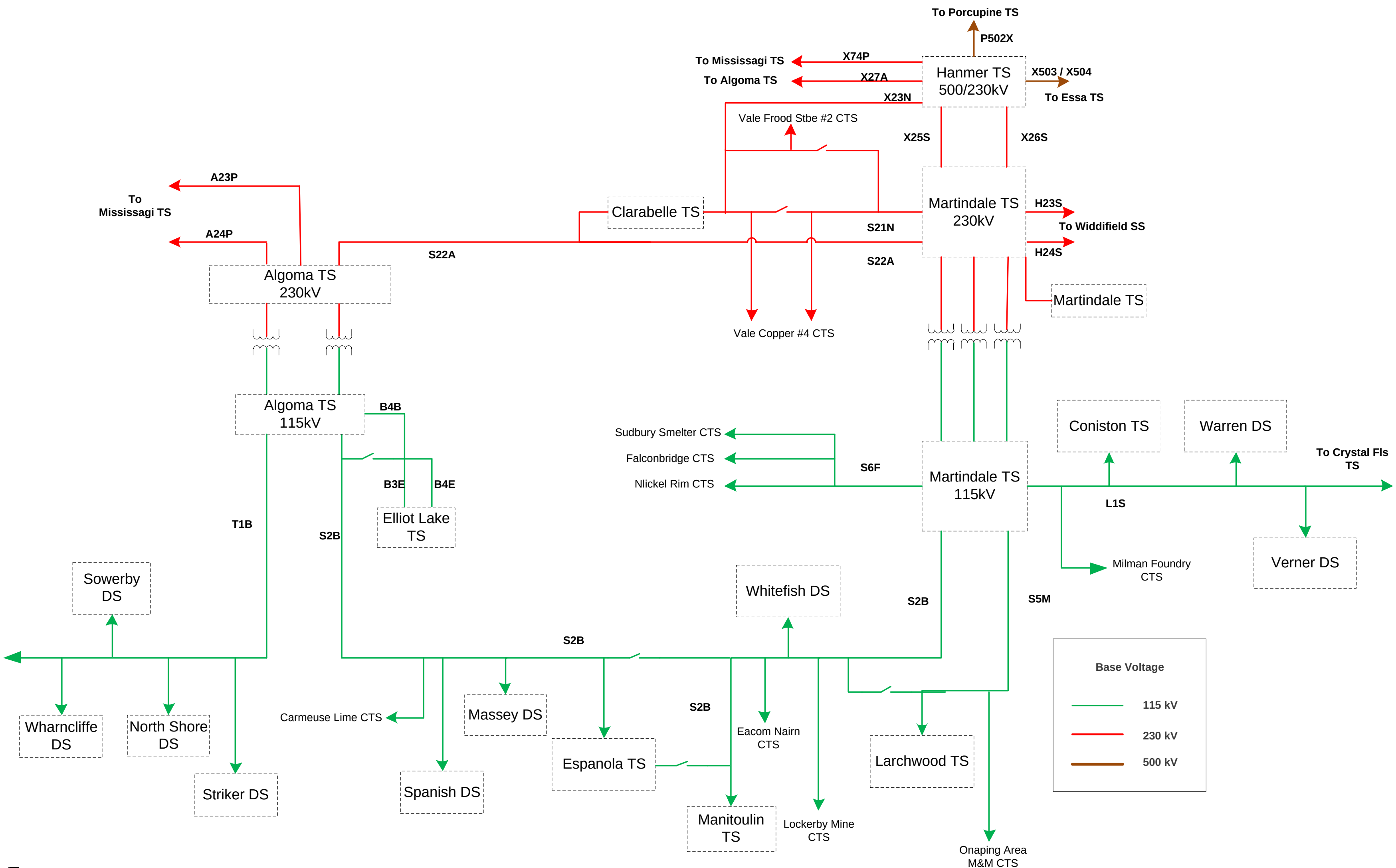

Figure 2: Single Line Diagram – Sudbury to Algoma Region

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- IESO provided:
    i. Historical 2013 regional coincident peak load and station non-coincident peak load
    ii. List of existing reliability and operational issues
    iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2011-2013) net load and gross load forecast (2014-2023)
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.3% annually from 2014-2023.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. The net load is expected to decrease at an average rate of approximately 0.2% annually from 2014-2023.

5 NEEDS ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

1. The Region is winter peaking so this assessment is based on winter peak loads.
2. Forecast loads are provided by the Region's LDCs (Greater Sudbury Hydro Inc, Hydro One Distribution).
3. Load data was provided by industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
4. The LDC's load forecast is translated into load growth rates and is applied onto the 2013 winter peak load as a reference point.
5. The 2013 winter peak loads are adjusted for extreme weather conditions according to Hydro One's methodology.

6. Accounting for (2), (3), (4) above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG is analyzed to determine if needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for Section 6.1.3 of this report.
   A gross and net region-coincident peak load forecast was used to perform the analysis for sections 6.1.1 and 6.1.2.
   Review impact of any on-going and/or planned development projects in the Region during the study period.
7. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
8. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer or winter 10-Day Limited Time Rating (LTR), as appropriate.
9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their winter long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using winter loading with winter 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Sudbury to Algoma Region.

6.1 Transmission Capacity Needs

6.1.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Algoma TS, Martindale TS, Hanmer TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

6.1.2 Transmission Lines & Ratings

The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

The 115 kV circuits supplying the Region are adequate over the study period.

6.1.3 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station winter peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period (2014-2023).

6.1.4 Pre-contingency voltages at Manitoulin TS 115kV

Pre-contingency voltages at Manitoulin TS 115kV bus can be below the ORTAC criteria of 113 kV. This issue has been also identified by the IESO as part of their System Impact Assessments.

6.2 System Reliability, Operation and Restoration

Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to The loss of two elements is below the load loss limit of 600MW by the end of the 10-year Study period. For the loss of one or two elements, the load interrupted by configuration does not exceed 150 MW or 250 MW. Review of the power network in the area indicates that all loads in the Sudbury-Algoma area can be restored within the 8 hour requirement.

6.2.1 Post contingency voltage declines at Martindale TS

With either X25S or X26S is out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable ORTAC limits. This issue has been presented in the IESO System Impact Assessment Victoria

Advanced Exploration Project (CAA 2013-512). In this assessment, voltage declines at the Martindale 230kV and 115 kV buses were found to be greater than the 10% limit.

6.2.2 Post Contingency Thermal Overload of Martindale Autotransformers

Under peak load conditions, the loss of two Martindale 230/115kV transformers may result in the overload of the third Martindale transformer. This issue has been presented in the IESO System Impact Assessment Process Gas (CAA 2012-488).

The double element contingency presented here occurs on the premise that all 115kV area loads would be supplied from one remaining autotransformer at Martindale TS. The worst case would be with Martindale T23 transformer remaining as it has the lowest STE (Short Term Emergency) rating.

Replacement of the autotransformers is listed in Hydro Ones 5yr sustainment business plan. T21/T23 autotransformers at Martindale TS may result in higher emergency ratings. In addition, loads connected to S2B (from Martindale) can also be transferred to S2B from Algoma, reducing Martindale 115kV load.

The above issues (6.2.1, 6.2.2) will be further assessed as part of bulk system planning outside of the regional planning process.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. During the study period:

- Replace T21/T23 230/115kV autotransformers at Martindale TS
- Build a new 230/44kV station at Hanmer TS to replace Coniston TS (115/22kV). As part of this project, Coniston loads will be converted from 22kV to 44kV
- Replace 115/44kV power transformers at Espanola TS (T1/T2) and Larchwood TS (T2)

7 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, the study team recommends that no further coordinated regional planning is required. It is further recommended that following needs identified be best addressed by wires options thru local planning led by Hydro One:

Manitoulin TS - Pre-contingency voltages

- Low pre-contingency voltages at 115kV Manitoulin TS.

8 NEXT STEPS

Following the Needs Assessment process, the next regional planning steps, based on the evaluation conducted by this assessment is for Hydro One Transmission and impacted LDCs to carry out the local planning studies identified in Section 7

9 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

10 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Chatham-Kent/Lambton/Sarnia

Regional Infrastructure Plan

August 21, 2017

Prepared by Hydro One Networks Inc. (Lead Transmitter)

With support from:

Companies
Independent Electricity System Operator (IESO)
Bluewater Power Distribution Corporation
Entegrus Inc.
Hydro One Networks Inc. (Distribution)

Disclaimer

This Regional Infrastructure Plan ("RIP") was prepared for the purpose of developing an electricity infrastructure plan to address needs identified in the Chatham-Kent/Lambton-Sarnia Region. The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the members in the region.

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EXECUTIVE SUMMARY

This Regional Infrastructure Plan ("RIP") was prepared by Hydro One, with input from the Region's Local Distribution Companies ("LDCs") and the IESO in accordance with the Ontario Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements. It summarizes investments in transmission facilities, distribution facilities, or both, recommended to meet the electricity infrastructure needs within the Chatham-Kent/Lambton/Sarnia Region.

The regional planning process for the Chatham-Kent/Lambton/Sarnia Region was initiated with a Needs Assessment in April 2016, which identified loading at Kent TS would exceed their transformer 10-day Limited Time Rating ("LTR") in 2016 based on the net load forecast. The Needs Assessment Study Team recommended Hydro One and relevant LDCs to develop a Local Plan to address this issue ("Kent TS T3 Capacity Limitation"). This Local Plan was completed in June 2017, and concluded that there is existing distribution transfer capability to ensure that the transformer T3 would not exceed its LTR.

The major sustainment projects planned for the region over the near and medium-term are given as below:

- Refurbishment of existing Wanstead TS is currently underway and is scheduled to be completed in 2018;
- Chatham SS component replacement, including a capacitor and the associated breaker, is planned to be completed by 2023;
- St. Andrews TS T3, T4 & switchyard refurbishment, planned to be completed by 2023;
- Sarnia Scott TS T5 & Component Replacement, which includes autotransformer T5, breaker, and other components, planned to be completed by 2024.

In accordance with the regional planning process as mandated by the TSC and DSC, the next planning cycle will be started no later than 2020. However, should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle may commence earlier to address the need.

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1. INTRODUCTION

This Regional Infrastructure Plan ("RIP") summarizes all the regional planning activities undertaken in the Chatham-Kent/Lambton/Sarnia Region. It was prepared by Hydro One Networks Inc. ("Hydro One") as the lead transmitter in the region, and is supported by the representatives from Bluewater Power Distribution Corporation, Entegrus Inc., Hydro One Networks Inc. (Distribution), and the Independent Electricity System Operator ("IESO"). This RIP is the final phase of the regional planning process for the region in accordance with the Ontario Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements.

1.1 Background and Scope

In accordance with the TSC and DSC amendments in August 2013, the regional planning process for the Chatham-Kent/Lambton/Sarnia Region began with Needs Assessment in April 2016 and was completed in June 2016.

Based on the findings, the Needs Assessment Study Team agreed that Scoping Assessment was not required for this region at the time. The only need identified, thermal overloading of transformer T3 at Kent TS, was to be addressed between Hydro One (transmitter) and relevant LDCs through Local Planning process which was completed in June 2017.

Being the final phase of the regional planning process, the scope of this RIP includes a comprehensive summary of the needs and relevant wire plans to address near and medium-term needs (2015-2025) identified in previous planning phases.

2. REGIONAL DESCRIPTION

The Chatham-Kent/Lambton/Sarnia Region, as shown in Figure 2-1, includes the municipalities of Lambton Shores and Chatham-Kent, as well as the townships of Petrolia, Plympton-Wyoming, Brooke-Alvinston, Dawn-Euphemia, Enniskillen, St. Clair, Warwick, and Villages of Oil Springs and Point Edward. The area is bordered by the London area to the east and Windsor-Essex to the southwest. The region's summer coincident peak load was about 710 MW in 2016.

Figure 2-1 Map of Chatham-Kent/Lambton/Sarnia Region

Electricity supply for the region is provided through a network of 230 kV and 115 kV transmission lines. The bulk of the electrical supply is transmitted through 230 kV circuits (N21W/N22W, L24L/L26L, and W44LC/W45LS) towards Buchanan TS. This region also contains a number of interconnections with neighboring Michigan State (B3N, L4D, and L51D). Figure 2-2 shows Hydro One transmission and transmission-connected customers' assets in the Chatham-Kent/Lambton/Sarnia Region.

Large gas-fired generators in the region include: Greenfield Energy Centre CGS, TransAlta Sarnia CGS, St. Clair Power CGS, and Greenfield South Power Corporation (GSPC). Lists of transmission lines, stations, and distributors (LDCs) in the region are provided in Appendix A, B, and C, respectively.

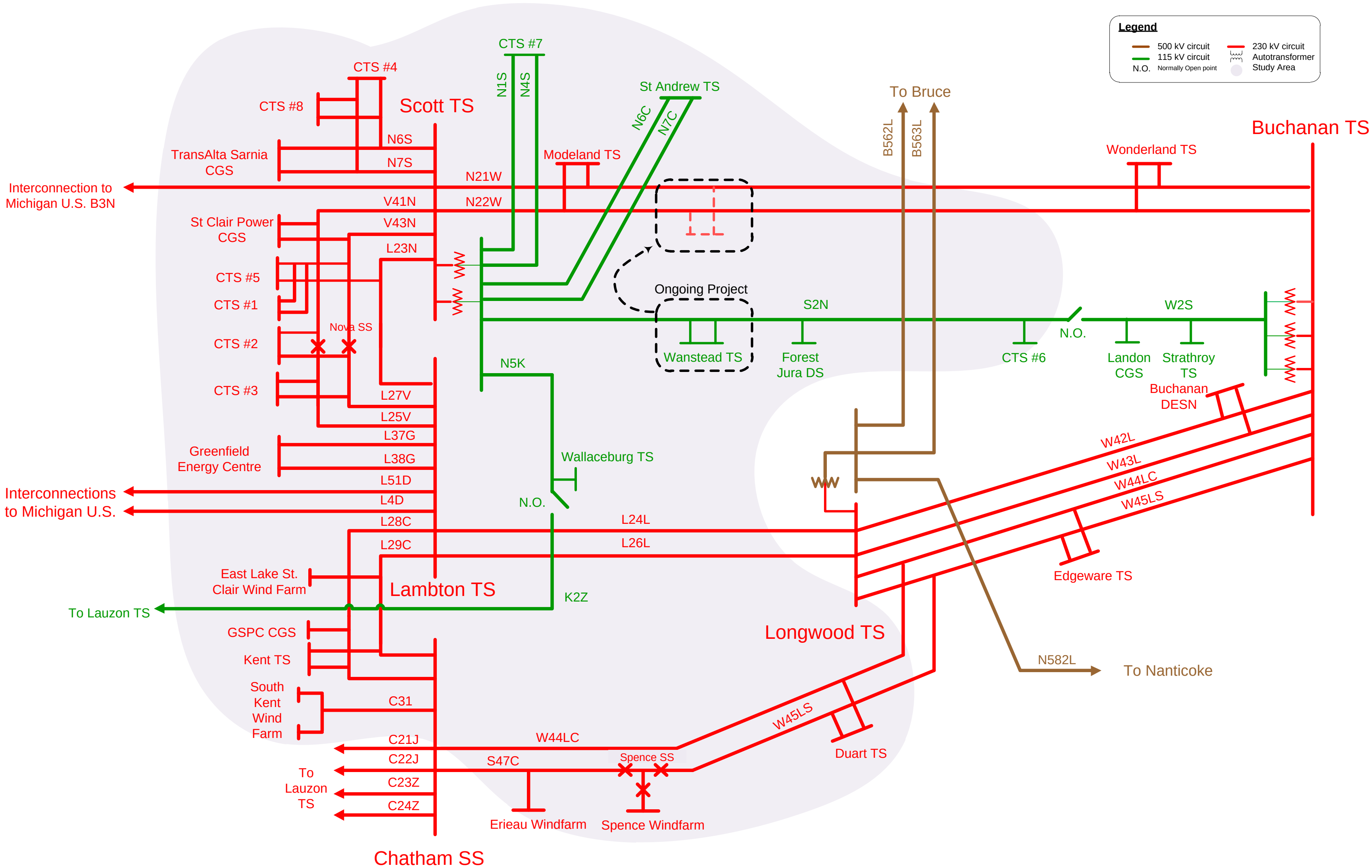


Figure 2-2 Single Line Diagram of Chatham-Kent/Lambton/Sarnia Region

3. NEEDS ASSESSMENT RESULTS

3.1 Load Forecast

During the Needs Assessment phase, LDCs in the region provided gross load forecasts for Hydro One's step-down transformer stations and assumed 2015 historical extreme weather-corrected summer peak loads as reference points. As for transmission connected industrial customers, 2014 historical load levels were assumed throughout the study period.

Based on data provided by the Study Team, the summer gross coincident load in the region is expected to grow at an average rate of approximately 1.3% annually over the next 10 year period. Factoring in the contributions of conservation and demand management and distributed generation, the summer net coincident load in the region is expected to grow at an average rate of approximately 0.2% annually.

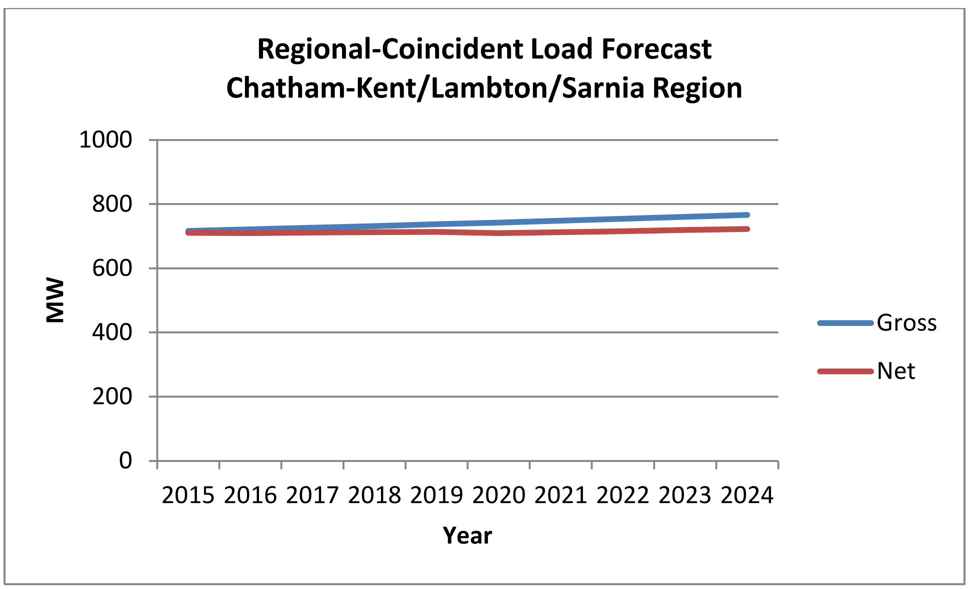


Figure 3-1 Regional load forecast during Needs Assessment

Further load forecast details are provided in Appendix D.

3.2 Major Transmission Projects Completed or Underway

Over the last 10 years, a number of major transmission projects, shown below, have been completed by Hydro One aimed to maintain or improve the reliability and adequacy of supply in the Chatham-Kent/Lambton/Sarnia Region:

- Lambton to Longwood 230kV L24L/L26L Circuit Reconductoring
- New Transformer Station Duart TS

In addition, as part of Hydro One's transmission rates application (EB-2016-0160), existing Wanstead TS has been identified as reaching end-of-life. Effort is underway to convert Wanstead TS from 115 kV to 230 kV and connecting to 230 kV circuits N21W/N22W. The target in-service date is Q4 2018.

3.3 Regional Needs

The results from the Needs Assessment for the region are summarized below:

Table 3-1 Regional Needs

No.	Needs	Description
1	Kent TS Capacity	Loading at Kent TS is expected to exceed the transformer 10-day limited time rating (LTR) in 2016 based on the net load forecast.
2	End-of-Life equipment at St. Andrews TS, Scott TS, and Chatham SS	During the study period, plans to replace end of life equipment at St. Andrews TS, Scott TS, and Chatham SS[1] are identified.

4. RECOMMENDED PLANS

This section provides a consolidated summary of the regional infrastructure plans for addressing needs in the Chatham-Kent/Lambton/Sarnia Region.

4.1 Kent TS Transformation Capacity

Based on the information available at the time of Chatham-Kent/Lambton/Sarnia Region Needs Assessment, it was identified that transformer T3 at Kent TS will be overloaded for the loss of its companion transformer T4. Subsequently, local planning team consists of Hydro One and impacted LDCs had undertaken further investigations and determined there is a sufficient transfer capability on the distribution system to offload Kent TS T3. Therefore, the local planning team agreed no further action is required at this time.

[1] The need to replace end-of-life equipment at Chatham SS was identified post completion of the 2016 Needs Assessment report.

4.2 Sustainment Plans

As part of Hydro One's transmitter license requirements, Hydro One continues to ensure a reliable transmission system by carrying out maintenance programs as well as periodic replacement of equipment based on their condition. Since the conclusion of Needs Assessment, additional sustainment projects have been planned for the region in the medium-term. Below is a list of Hydro One's major transmission sustainment projects in the Chatham-Kent/Lambton/Sarnia Region that are currently planned. Note that the project scopes and timelines are currently under development and may change accordingly.

- Chatham SS Component Replacement, mainly to replace capacitor SC21 and the associated breaker and is planned to be completed by 2023.
- St. Andrews TS T3, T4 & Switchyard Refurbishment, planned to be completed by 2023. The current scope includes both transformers and a breaker replacement.
- Sarnia Scott TS T5 & Component Replacement, which includes autotransformer T5, breaker, and other components, planned to be completed by 2024.

5. CONCLUSION AND NEXT STEPS

This Regional Infrastructure Plan (RIP) report summarizes the regional planning activities for the Chatham-Kent/Lambton/Sarnia Region and concludes the first regional planning cycle for the region.

As mandated by the OEB, next planning cycle will begin no later than 2020. Should there be a need that emerges due to change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

6. REFERENCES

[1] Needs Assessment Report, Chatham-Kent/Lambton/Sarnia Region. June 12, 2016. http://www.hydroone.com/RegionalPlanning/Chatham/Documents/Needs%20Assessment%20Report%20-%20Chatham-Kent-Lambton-Sarnia.pdf

[2] Local Planning Report – Kent TS Transformation Capacity, Chatham-Kent/Lambton/Sarnia Region. June, 2017. http://www.hydroone.com/RegionalPlanning/Chatham/Documents/Kent%20TS%20Transformation%20Capacity%20Local%20Planning%20Report%20(Final).pdf

APPENDIX A: TRANSMISSION LINES IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

No	Circuit Designation	Location	Voltage (kV)
1	N6S, N7S	Scott TS to TransAlta Sarnia CGS	230
2	V41N, V43N	Scott TS to Nova SS	230
3	L23N	Scott TS to Lambton TS	230
4	L25V, L27V	Lambton TS to Nova SS	230
5	L37G, L38G	Lambton TS to Greenfield Energy Centre CGS	230
6	L28C, L29C	Lambton TS to Chatham SS	230
7	C31	Chatham SS to South Kent Wind Farm CGS	230
8	W44LC	Buchanan TS to Longwood TS to Chatham SS	230
9	W45LS	Buchanan TS to Longwood TS to Spence SS	230
10	S47C	Spence SS to Chatham SS	230
11	L24L, L26L	Lambton TS to Longwood TS	230
12	N21W, N22W	Scott TS to Buchanan TS	230
13	N1S, N4S	Scott TS to CTS	115
14	N6C, N7C	Scott TS to St. Andrews TS	115
15	S2N	Scott TS to CTS	115
16	N5K	Scott TS to Wallaceburg TS	115
17	K2Z	Kent TS (115kV) to Lauzon TS	115

APPENDIX B: STATIONS IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

No.	Station	Voltage (kV)	Supply Circuits
1	Scott TS	230/115	N/A
2	Lambton TS	230	N/A
3	Kent TS	115	L28C/L29C
4	Duart TS	230	W44LC, W45LS
5	Modeland TS	230	N21W, N22W
6	Wanstead TS	115 (existing) 230 (future)	S2N (existing) N21W/N22W (future)
7	St. Andrews TS	115	N6C, N7C
8	Wallaceburg TS	115	N5K
9	Forest Jura HVDS	115	S2N

Note: Customer-owned transformer stations are excluded

APPENDIX C: DISTRIBUTORS IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

Distributor Name	Station Name	Connection Type
Bluewater Power Distribution Corporation	Modeland TS	Tx
	St. Andrews TS	Tx
	Wanstead TS	Dx
Entegrus Inc.	Kent TS	Tx, Dx
	Wallaceburg TS	Dx
Hydro One Networks Inc. (Distribution)	Duart TS	Tx
	Forest Jura HVDS	Tx
	Kent TS	Tx
	Lambton TS	Tx
	Wallaceburg TS	Tx
	Wanstead TS	Tx

APPENDIX D: REGIONAL-COINCIDENT LOAD FORECAST (MW)

Coincidental Net Load (MW)

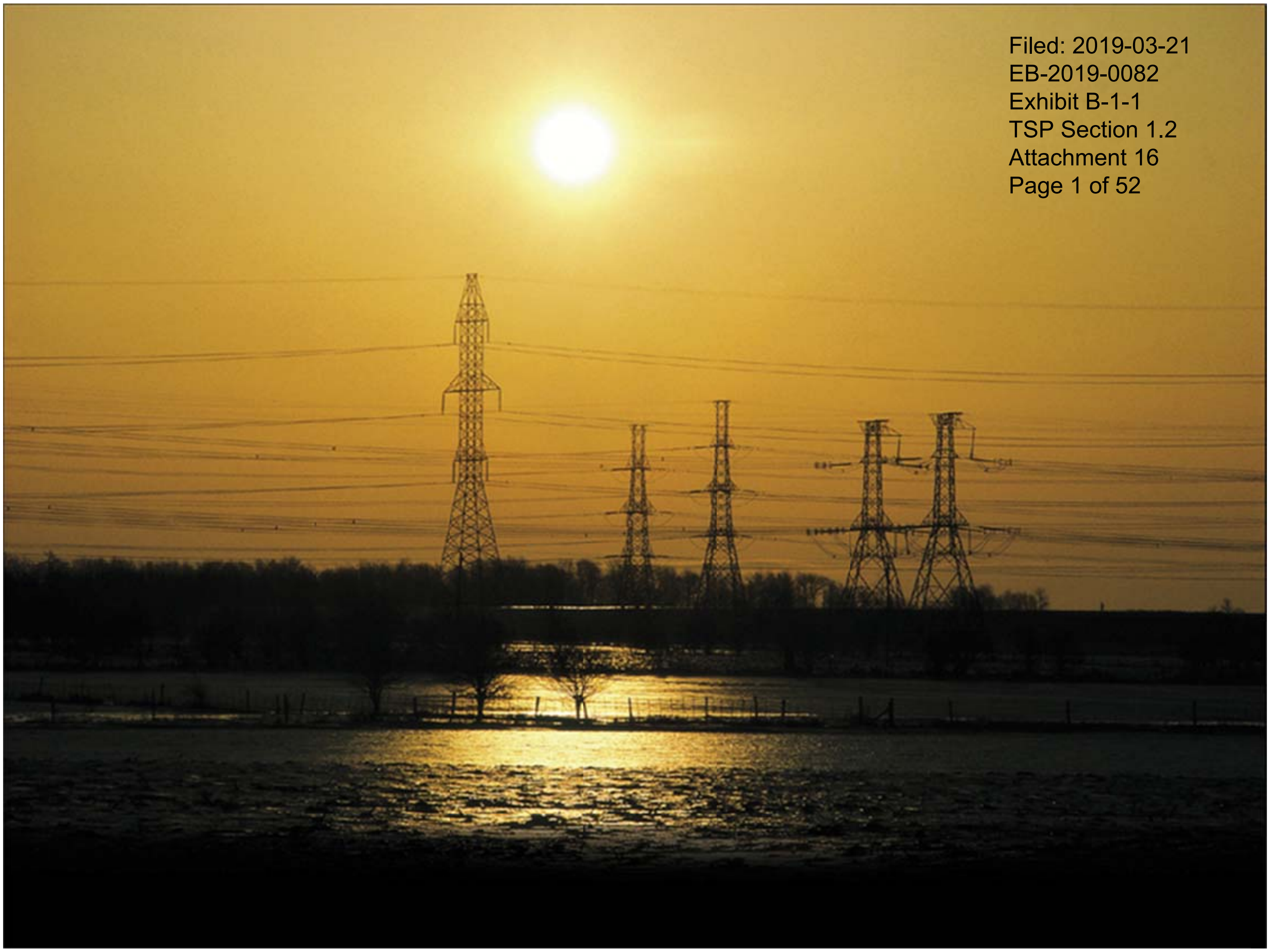
	Forecast (MW)									
Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Duart TS	14.5	14.5	14.4	14.5	14.5	14.6	14.7	14.8	15.0	15.1
Forest Jura DS	19.5	19.6	19.8	19.9	20.0	20.2	20.4	20.6	20.9	21.1
Kent TS T1/T2	69.8	70.0	71.1	72.0	72.9	74.0	75.3	76.6	78.1	79.5
Kent TS T3/T4	40.3	40.7	41.3	41.8	42.2	42.8	43.5	44.2	45.0	45.8
Lambton TS	61.7	61.6	61.8	61.7	61.6	61.7	61.9	62.2	62.5	62.8
Modeland TS	82.1	81.4	81.2	80.6	80.1	79.7	79.5	79.4	79.4	79.2
St. Andrews TS	63.0	62.3	61.8	61.1	60.5	60.0	59.6	59.3	59.0	58.7
Wallaceburg TS	27.0	26.8	27.2	27.6	27.9	23.2	23.7	24.2	24.8	25.3
Wanstead TS	28.1	28.2	28.5	28.6	28.8	29.0	29.3	29.6	30.0	30.3
CTS #1	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
CTS #2	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
CTS #3	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
CTS #4	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
CTS #5	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9
CTS #6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
CTS #7	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9
CTS #8	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7

Coincidental Gross Load (MW)

	Forecast (MW)									
Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Duart TS	14.7	14.9	15.1	15.3	15.5	15.7	16.0	16.2	16.4	16.7
Forest Jura DS	19.7	20.0	20.4	20.7	21.1	21.4	21.8	22.2	22.6	22.9
Kent TS T1/T2	71.1	72.7	74.4	76.1	77.9	79.7	81.6	83.5	85.4	87.4
Kent TS T3/T4	40.8	41.7	42.6	43.6	44.6	45.5	46.6	47.6	48.7	49.8
Lambton TS	62.3	62.9	63.5	64.1	64.8	65.4	66.1	66.7	67.4	68.0
Modeland TS	82.9	83.3	83.6	84.0	84.3	84.7	85.0	85.3	85.7	86.0
St. Andrews TS	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6
Wallaceburg TS	27.7	28.3	29.0	29.7	30.3	31.0	31.8	32.5	33.3	34.0
Wanstead TS	28.7	29.2	29.7	30.1	30.6	31.1	31.6	32.2	32.7	33.2
CTS #1	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
CTS #2	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
CTS #3	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
CTS #4	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
CTS #5	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9
CTS #6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
CTS #7	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9
CTS #8	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7

APPENDIX E: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council Inc.
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code



Greater Bruce - Huron

REGIONAL INFRASTRUCTURE PLAN

August 18, 2017

hydro one

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Entegrus Power Lines Inc.
Erie Thames Powerlines Corporation
Festival Hydro Inc.
Goderich Hydro - West Coast Huron Energy Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Wellington North Power Inc.
Westario Power Inc.

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Disclaimer

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs (2016-2025) identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GREATER BRUCE-HURON REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Entegrus Power Lines Inc.
- Erie Thames Powerlines Corporation
- Festival Hydro Inc.
- Goderich Hydro - West Coast Huron Energy Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Wellington North Power Inc.
- Westario Power Inc.

This RIP is the final phase of the regional planning process for the Greater Bruce-Huron Region and provides a consolidated summary of needs and recommended plans for the Greater Bruce-Huron Region for the near-term (up to 5 years) and mid-term (5 to 10 years). No long term needs (10 to 20 years) have been identified.

Investments planned for the Greater Bruce-Huron Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the table below.

No.	Project	In-Service Date	Cost
1	Improve L7S Customer Delivery Point Performance	Staged Plan 2017-2023	$154k - TBD
2	Accommodation for Connection Capacity Requests near Kincardine– Hydro One Network Inc. Distribution	TBD (customer dependent)	TBD

In accordance with the Regional Planning process, the RIP should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be started to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE GREATER BRUCE-HURON REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) and documents the results of the joint study carried out by Hydro One, Entegrus Power Lines Inc., Erie Thames Powerlines Corporation, Festival Hydro Inc., Hydro One Distribution, the Independent Electricity System Operator (“IESO”), Wellington North Power Inc., Goderich Hydro - West Coast Huron Energy Inc. and Westario Power Inc. in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

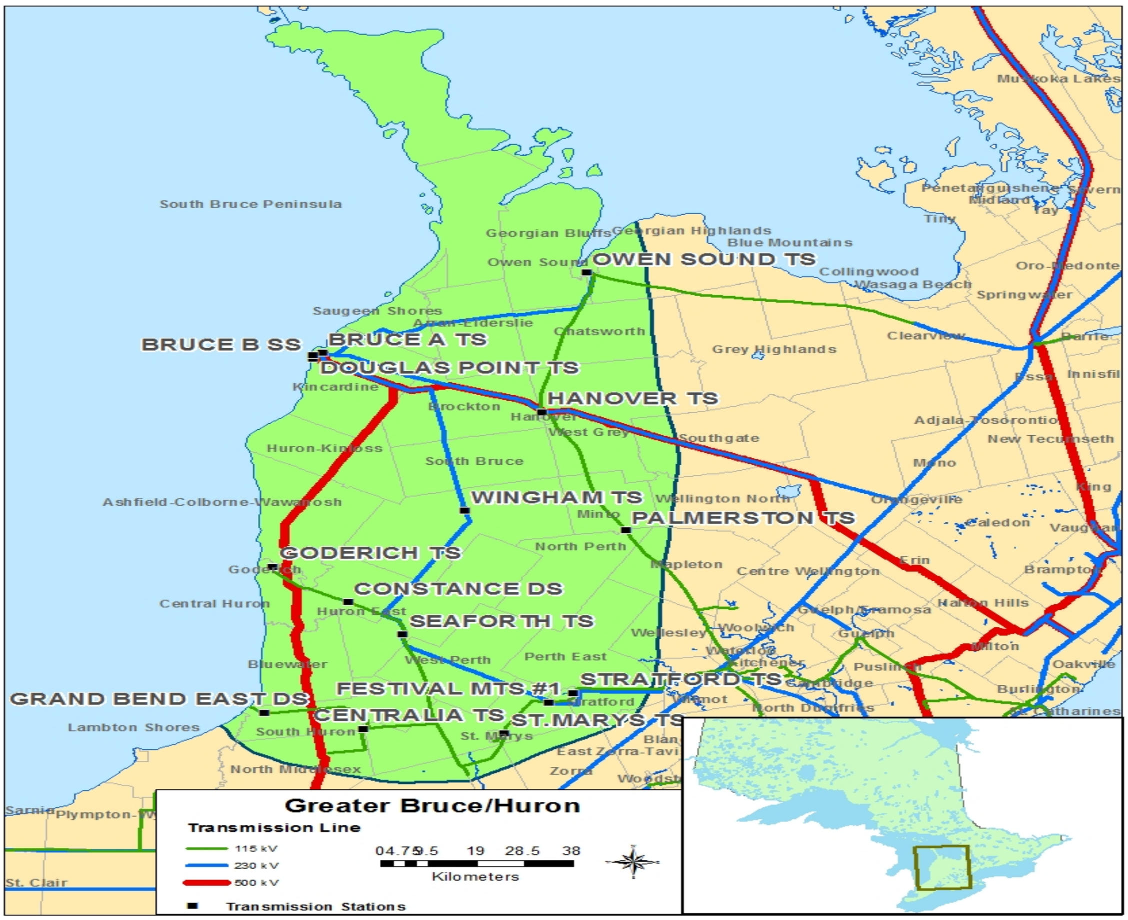

Figure 1-1 Greater Bruce-Huron Region

The Greater Bruce-Huron Region includes the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford and Middlesex counties. Electrical supply to the Region is provided from six 230 kV and twelve 115 kV step-down transformer stations. The boundaries of the Region are highlighted in Figure 1-1 above.

1.1 Objective and Scope

This RIP report examines the needs in the Greater Bruce-Huron Region. Its objectives are:

- To develop a wires plan to address needs identified in previous planning phases for which a wires only alternative was recommended by the Working Group
- To identify new supply needs that may have emerged since previous planning phases (e.g. Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan)
- To provide the status of wires planning currently underway or completed for specific needs
- To identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region

The RIP reviewed factors such as the load forecast, major high voltage sustainment work, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management (CDM), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2016-2025) identified in previous planning phases (Needs Assessment or Local Plan)
- Identification of any new needs over the 2016-2025 period
- Develop a plan to address any longer term needs identified by the Working Group

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the region
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies needs
- Section 7 summarizes the Regional Plan to address the needs
- Section 8 provides the conclusion and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013, through amendments to the Transmission System Code ("TSC") and the Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ('SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource options (e.g. CDM, generation and Distributed Energy Resources ("DER")) at a higher or more macro level but sufficient to permit a comparison of options. If the IRRP process identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the

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[1] Also referred to a Needs Screening

specific wires alternatives and recommend the preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution was determined to be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timeliness provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the Greater Bruce-Huron region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- The NA and LP phases of regional planning.
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

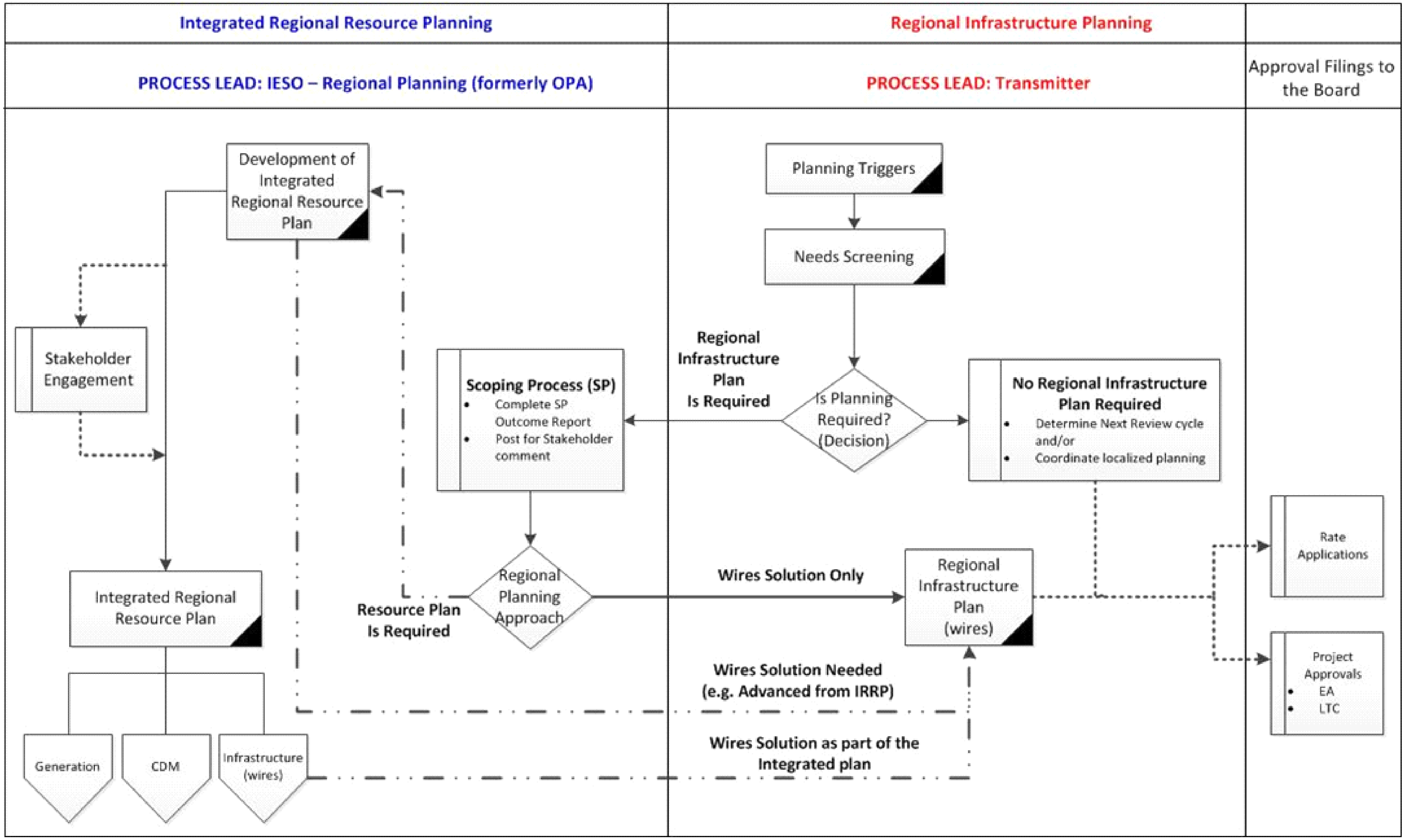

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1. Data Gathering: The first step of the RIP phase is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Gross and net peak demand forecast at the transformer station level. This includes the effect of any distributed generation and/or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

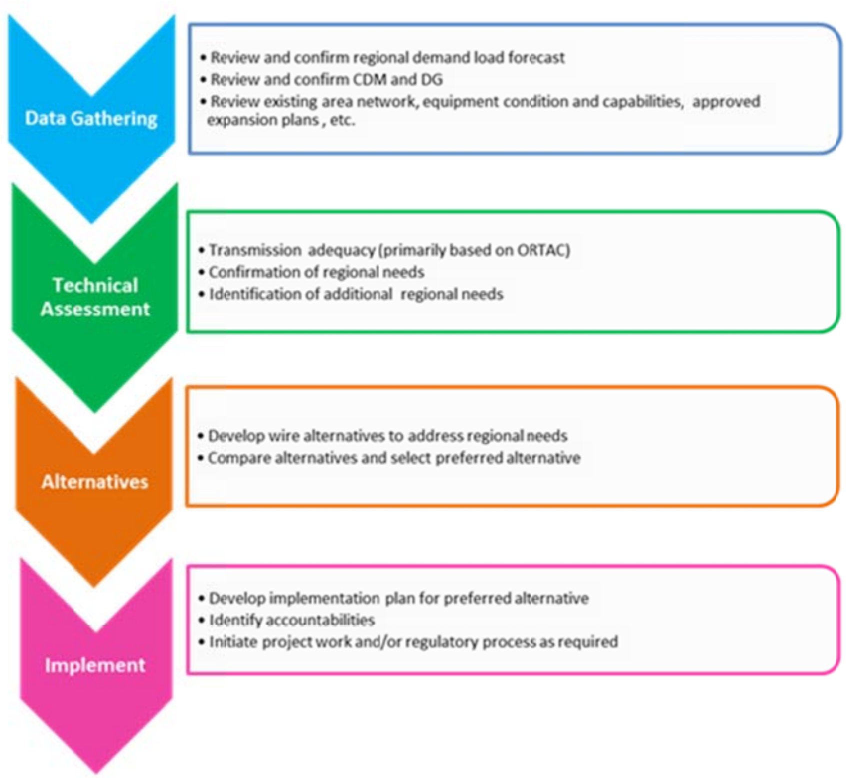

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GREATER BRUCE-HURON REGION COMPRISES OF THE COUNTIES OF BRUCE, HURON, AND PERTH, AS WELL AS PORTIONS OF GREY, WELLINGTON, WATERLOO, OXFORD, AND MIDDLESEX COUNTIES AS SHOWN IN FIGURE 3-1.

Electricity supply for the Region is provided through a network of 230 kV and 115 kV transmission lines supplied mainly by generation from the Bruce Nuclear Generating Station and local renewable generation facilities in the Region. The majority of the electrical supply in the region is transmitted through 230 kV circuits (B4V, B5V, B22D, B23D, B27S and B28S) radiating out from Bruce A TS. These circuits connect the Region to the adjacent South Georgian Bay/Muskoka Region and the adjacent Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region.

Within the Region, electricity is delivered to the end users of LDCs and directly-connected industrial customers by eleven Hydro One step-down transformation stations, as well as seven customer-owned transformer or distribution stations supplied directly from the transmission system. Appendix A lists all step-down transformer stations in the Region. Appendix B lists all transmission circuits and Appendix C lists LDCs in the Region. The Single Line Diagram for the Greater Bruce-Huron Region transmission system facilities is shown below in Figure 3-2.

Figure 3-1 Geographical Area of the Greater Bruce-Huron Region with Electrical Layout

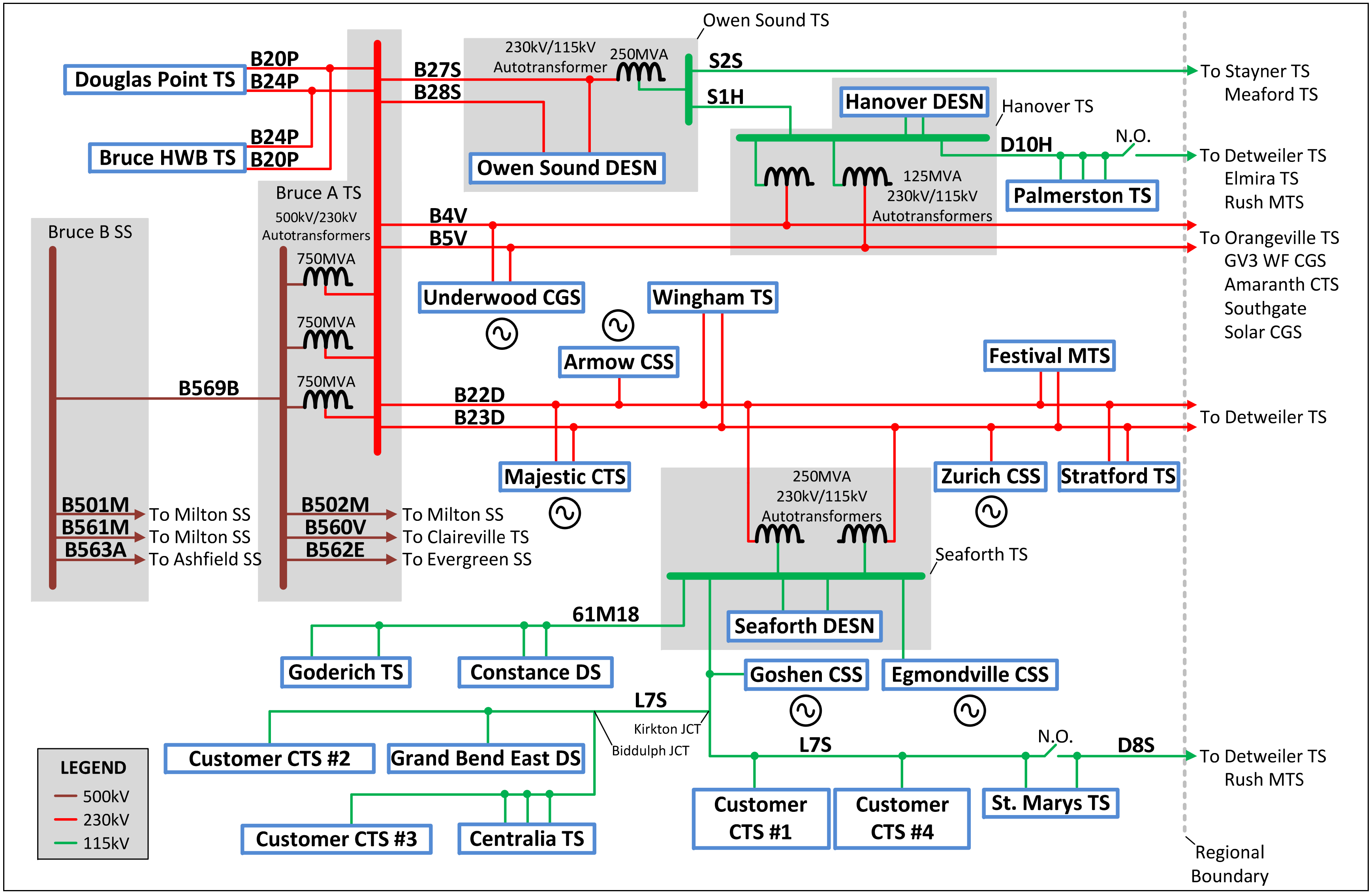

Figure 3-2 Greater Bruce-Huron Region Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GREATER BRUCE-HURON REGION.

In addition to Hydro One's ongoing transmission station and line sustainment programs, specific projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For reactive and voltage support needs:

- a 230 kV shunt capacitor bank installed at Detweiler TS in 2007
- a 230 kV shunt capacitor bank installed at Orangeville TS in 2008

For bulk power system transfer needs:

- 500 kV double circuit line from the Bruce Nuclear Complex to Milton SS in 2011
- 230 kV Static Var Compensator (SVC) at Detweiler TS in 2011

For major station refurbishment needs based on asset condition assessment:

- Goderich TS in 2016

For renewable generation connection needs:

- 230 kV Melancthon Grey Wind Farm onto circuits B4V/B5V in 2006/2008
- 230 kV Ripley Wind Farm onto circuits B22D/B23D in 2007
- 230 kV Underwood Wind Farm onto circuits B4V/ B5V in 2008
- 230 kV Dufferin Wind Farm into Orangeville TS in 2014
- 500 kV Jericho/Adelaide/Bornish Wind Farms into Evergreen SS in 2014
- 230 kV Grand Valley 3 Wind Farm onto circuit B4V in 2015
- 115 kV Bluewater Wind Farm into Seaforth TS in 2015
- 115 kV Goshen Wind Farm onto circuit L7S in 2015
- 500 kV K2 Wind Farm into Ashfield SS in 2015
- 230 kV Grand Bend Wind Farm onto circuit B23D in 2016
- 230 kV Armow Wind Farm onto circuit B22D in 2016
- 230 kV Southgate Solar Farm onto circuit B4V in 2016

The following projects are underway:

- Centralia TS is currently undergoing major station refurbishment work with a projected in-service of 2018.
- Palmerston TS is currently undergoing major station refurbishment work with a projected in-service of 2018.
- Bruce A TS 230 kV switchyard is currently undergoing major station refurbishment work with a projected in-servicing by 2019.
- Replacement of the Bruce Special Projection Scheme (BSPS) is currently underway with a projected in-service of 2018.
- Modification to the Bruce Reactor Switching Scheme (RSS) is currently underway with a projected in-service of 2018.

5. LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Greater Bruce-Huron Region is forecast to increase annually between 2016 and 2025. The growth rate varies across the Region with most of the growth concentrated in the County of Bruce and more specifically in the Kincardine area. The Region's 2017 RIP load forecasts are provided in Appendix D and were prepared by the Working Group upon initiation of the RIP phase. The RIP forecasts are identical to the Needs Assessment forecast except as otherwise noted in Appendix D.

As per the load forecasts in Appendix D, the winter *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.4% annually from 2016-2025 and the summer *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.3% from 2016-2025.

As per the load forecasts in Appendix D, the winter *net* coincident load in the Region is expected to grow at an average rate of approximately 0.8% annually from 2016-2025 and the summer *net* coincident load in the Region is expected to grow at an average rate of approximately 0.6% from 2016-2025.

Figure 5-1 shows the Region's gross and net *winter* coincident forecasts while Figure 5.2 shows the Region's gross and net *summer* coincident forecasts. The regional-coincident (at the same time) forecast represents the total peak load of all 18 step-down transformer stations in the Region.

Based on historical load and on the coincident load forecasts, the Region's winter coincident peak load is larger than its summer coincident peak load. Based on historical load and the non-coincident load forecasts, the Region contains some stations that are summer peaking and others that are winter peaking. Equipment ratings are normally lower in the summer than winter due to ambient temperature. Based on these factors assessment for this Region was conducted for both summer and winter peak load.

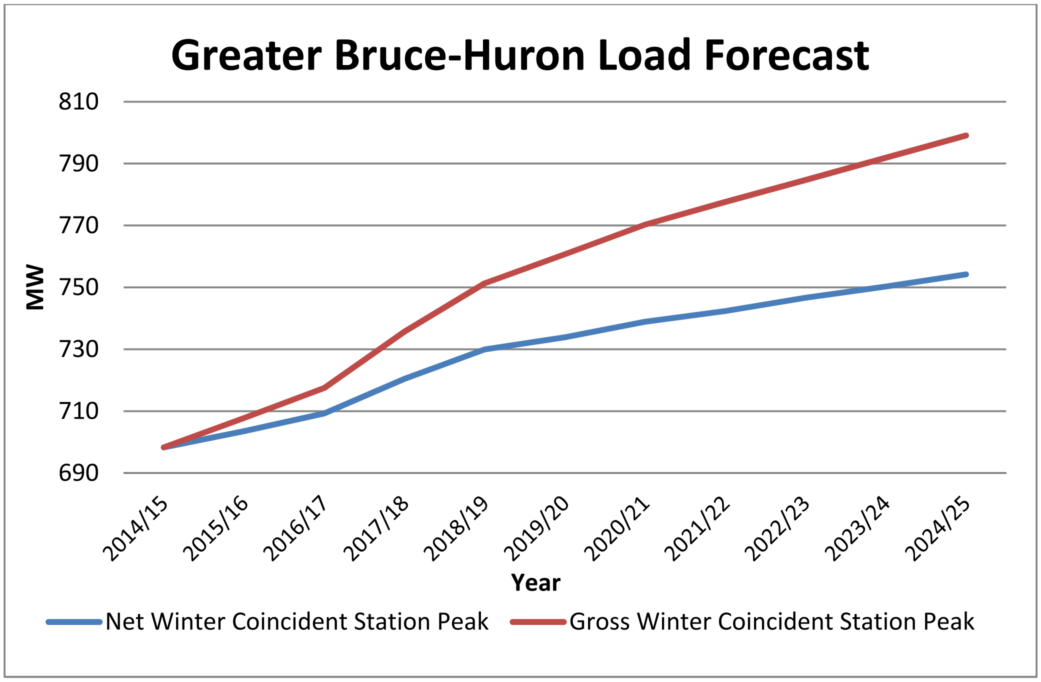

Figure 5-1 Greater Bruce-Huron Region Winter Extreme Weather Peak Forecast

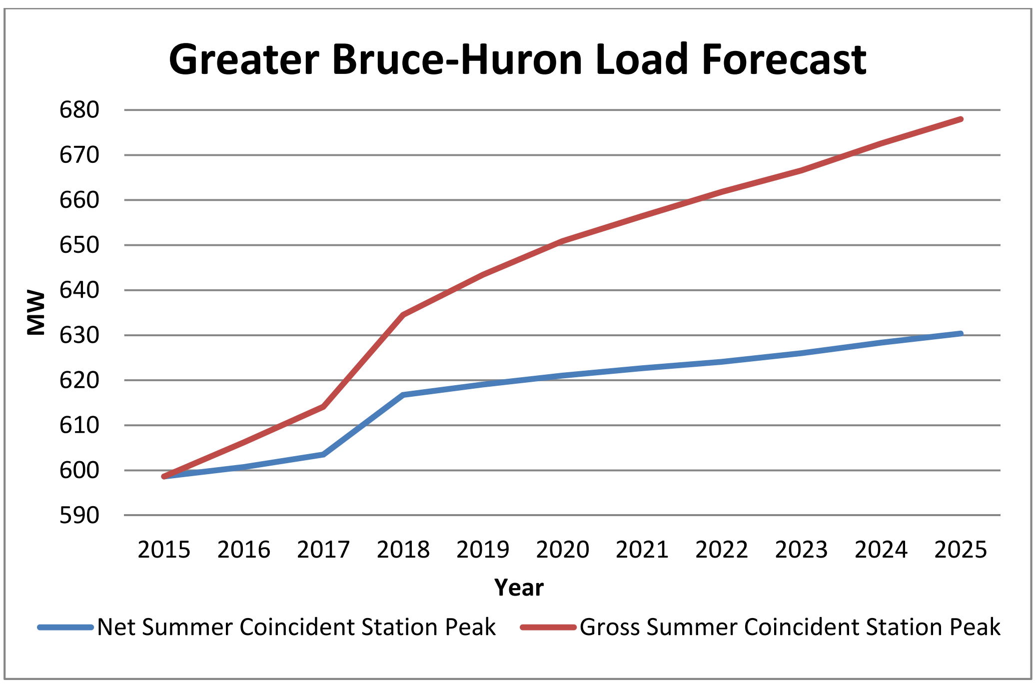

Figure 5-2 Greater Bruce-Huron Region Summer Extreme Weather Peak Forecast

5.2 Study Assumptions

The following assumptions are made in this report.

1) The study period for the RIP assessments is 2016-2025.

2) All planned facilities listed in Section 4 are assumed to be in-service.

3) The Region contains some stations that are summer peaking and others that are winter peaking. The assessment is therefore based on both summer and winter peak loads.

4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer and winter 10-Day Limited Time Rating (LTR), as appropriate.

5) Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2016-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STEP-DOWN TRANFORMATION STATION FACILITIES SUPPLYING THE GREATER BRUCE-HURON REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle, five regional assessments have been conducted for the Greater Bruce-Huron Region. The findings of these studies are input to the RIP. The studies are:

1) Needs Assessment Report - Greater Bruce-Huron Region, May 2016
2) Local Planning Report - Low Power Factor at Wingham TS, October 2016
3) Local Planning Report - Circuit L7S Thermal Overload, November 2016
4) Local Planning Report - Low Power Factor at Bruce HWP B TS, May 2017
5) Customer Delivery Point Performance Review, 2016-2017

This RIP reviewed the loading on transmission lines and stations in the Greater Bruce-Huron Region based on the RIP load forecast. Sections 6.1-6.6 presents the results of this review and Table 6-1 lists the Region's needs identified in both the Needs Assessment and the RIP phases.

In addition, this RIP reviewed an updated list of Hydro One transmission lines and station major sustainment work over the next several years to determine if there are opportunities to consolidate with any emerging development needs within the Region. Section 7.5 presents the results of this review.

Table 6-1: Near and Mid-term Regional Needs

<table>
<tr><th>Type</th><th>Section</th><th>Needs</th><th>Timing</th></tr>
<tr><td colspan="4">Needs Identified in the Needs Assessment Report [1]</td></tr>
<tr><td rowspan="2">Transmission Circuit Capacity</td><td rowspan="2">6.3</td><td rowspan="2">Overload on sections of 115 kV single circuit line, L7S</td><td>2019 (based on gross load forecast)</td></tr>
<tr><td>2025 (based on net load forecast)</td></tr>
<tr><td rowspan="2">Power Factor Review</td><td rowspan="2">6.5.2</td><td>Low power factor at Wingham TS</td><td>Immediate</td></tr>
<tr><td>Low power factor at Bruce HWP B TS</td><td>Immediate</td></tr>
<tr><td>Customer Delivery Point Performance Review</td><td>6.5.1</td><td>Delivery points supplied from 115 kV circuits 61M18, L7S and D10H</td><td>Immediate</td></tr>
<tr><td colspan="4">Additional Needs identified in RIP Phase</td></tr>
<tr><td>Step-down Transformation Capacity</td><td>6.4</td><td>Hydro One Distribution (Kincardine area)</td><td>2019/2020</td></tr>
</table>

6.1 230 kV Transmission Facilities

Half of the 230 kV transmission circuits in the Greater Bruce-Huron Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the KWCG, Georgian Bay and GTA areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-2):

1) Bruce A TS to Orangeville TS 230kV transmission circuits B4V/B5V – supplies Hanover TS
2) Bruce A TS to Detweiler TS 230kV transmission circuits B22D/ B23D – supplies Wingham TS, Seaforth TS, Festival MTS #1, and Stratford TS
3) Bruce A TS to Owen Sound TS 230kV transmission circuits B27S/B28S – supplies Owen Sound TS
4) Bruce A TS to Douglas Point TS 230kV transmission circuits B20P/B24P – supplies Douglas Point TS and Bruce HWP B TS

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period.

6.2 500/230 kV and 230/115 kV Transformation Facilities

Bulk power supply to the Greater Bruce-Huron Region is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV autotransformers. The number and location of these autotransformers are as follows:

1) Three (3) 500/230kV autotransformers at Bruce A TS
2) Two (2) 230/115kV autotransformers at Seaforth TS
3) Two (2) 230/115kV autotransformers at Hanover TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the autotransformation supply capacity is adequate over the study period.

6.3 Supply Capacity of the 115 kV Network

The Greater Bruce-Huron Region contains four (4) single circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Hanover TS to Detweiler TS 115 kV transmission circuit D10H with Normally Open (N/O) point at Palmerston TS – supplies Palmerston TS & Elmira TS
2) Seaforth TS to Goderich TS 115 kV transmission circuit 61M18 – supplies Constance DS and Goderich TS
3) Seaforth TS to St. Marys TS 115 kV transmission circuit L7S – supplies Grand bend East DS, Lake Huron WTP CTS, Centralia TS, McGillivray R&BP CTS, Enbridge Bryanston CTS and St. Marys Cement CTS
4) Hanover TS to Owen Sound TS 115 kV transmission circuit S1H

The RIP review shows that based on current forecast station loadings, the supply capacity of the 115 kV network is adequate over the study period, except circuit L7S. Circuit L7S will exceed its thermal rating in 2019 based on gross load forecast, and in 2025 based on net load forecast.

6.4 Step-down Transformer Stations

There are 18 step-down transformer stations within the Greater Bruce-Huron Region. Fourteen supply electricity to LDCs and four are transmission-connected industrial customer stations. These stations are listed in Appendix C. Of the 18 stations, 3 of them are owned and operated by LDCs.

As part of both the Needs Assessment as well as this RIP, step-down transformation station capacity was reviewed. Since the May 2016 Needs Assessment, the load forecasts at Seaforth TS, Stratford TS and Douglas Point TS have been modified; refer to Appendix E for the analysis of these modifications. The analysis showed that the load forecasts at Seaforth TS and Stratford TS can still be accommodated. However, the load forecast modification at Douglas Point TS will result in its transformation capacity limit being exceeded towards the end of the study period, winter 2023/2024. This is due to a 15 MW request for capacity made since the May 2016 Needs Assessment.

Furthermore, since updating the RIP forecast there has been additional connection requests for 2.2 MW, 0.5 MW and 20 MW of capacity by 2019/2020 at Douglas Point TS. The 2.2 MW and 0.5 MW requests can be accommodated within the station’s transformation capacity limits; however the 20 MW request would result in Douglas Point TS exceeding its transformation capacity within the near term (2019/2020) and cannot be fully accommodated at this time. Therefore additional step-down transformation capacity at/near Douglas Point TS is needed.

Based on the requirements of the customer requesting the 20 MW of connection capacity, three “need” scenarios have been developed:

Scenario 1 – If the customer requires all 20 MW of capacity immediately, the need for additional step-down transformation capacity is required in 2019/2020. Hydro One Transmission will work with Hydro One Distribution and the customer to develop a plan to meet the increased capacity requirement. All costs for the additional capacity will be allocated to the benefitting customer(s) as per the Transmission System Code.

Scenario 2 – If the customer accepts an offering to connect a portion of its load, the need for additional step-down transformation capacity is required in 2021 due to the inherent "organic" growth of load. In order to meet the need timeline, an expedited coordinated regional planning process will be undertaken by the IESO, Hydro One Transmission and Hydro One Distribution. Cost allocation for additional investment will depend on the solution to address the need.

Scenario 3 – If the customer elects not to proceed with its connection request, the need for additional step-down transformation capacity is require by 2023/2024. CDM would help to defer the need and therefore it is recommended to monitor load growth and re-evaluate the need in the next regional planning cycle.

6.5 Other Items Identified During Regional Planning

6.5.1 Customer Delivery Point Performance

The Needs Assessment section 6.2.5 identified that a performance review of several 115 kV customer delivery points be undertaken. A summary of the review is provided in Appendix F.

6.5.2 Low Power Factor Concerns

The Needs Assessment sections 6.2.3 identified two stations which historically have low power factor: Wingham TS and Bruce HWB TS.

6.6 Long-Term Regional Needs

A long-term, beyond 10 year, analysis was not deemed necessary by the Working Group for the Region at this time and therefore no long-term studies have been undertaken. If new long-term needs were to arise, there is sufficient time to assess them in the next planning cycle which can also be started earlier to make timely investment decisions.

7. REGIONAL PLANS

THIS SECTION SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS LISTED IN TABLE 6-1.

7.1 Transmission Circuit Capacity

7.1.1 Circuit L7S

L7S is a single 115 kV circuit transmission line operated radial from Seaforth TS to St. Marys TS. As per section 6.1.3 of the Needs Assessment, the circuit will reach its Load Meeting Capability (“LMC”) in 2019 based on the gross load forecast and 2025 based on the net load forecast.

Recommended Plan and Current Status

To address the transmission circuit capacity needs for L7S, the Local Planning working group created a Development Plan which recommended monitoring load growth at stations supplied from circuit L7S. The Development Plan is detailed in the Local Planning report [3]. The Development Plan specified that when loading on L7S is expected to exceed its limits within a 3 year period, Hydro One Transmission will increase the thermal rating of the limiting spans of circuit L7S. The cost to increase the rating is currently estimated to be approximately $550 k. Strengthening L7S will be sufficient for supplying load connected to L7S load for the study period. Loading beyond the study period’s forecast may then require additional voltage support. Capacity cost allocation will be as per the Transmission System Code.

<u>Current Status of the Loading on Circuit L7S</u>

The past winter (2016/2017) loading on circuit L7S was reviewed in accordance with the Development Plan. Winter peak coincident loading on the circuit was approximately 65% of the circuit capacity and did not trigger the need to increase the rating. Monitoring will continue after each peak load season, winter and summer.

7.2 Power Factor Review

7.2.1 Wingham TS

Power factor at Wingham TS is often low and does not meet IESO Market Rule requirements. As per section 6.2.3 of the Needs Assessment, the low power factor at Wingham TS is to be managed by the transmitter and affected LDCs.

Recommended Plan and Current Status

The power factor review conducted by the Local Planning working group, showed that the power factor of the load itself remains within Market Rule requirements. Further investigation revealed that the low power factor is due to the connected Distributed Generation (DG). The investigation is detailed in the Local Planning report [2]. The Local Plan recommends no mitigation is required at this time and to seek IESO's direction on power factor requirements with respect to DG.

<u>Current Status of Power Factor with Respect to Distributed Generation</u>

At this time, IESO does not recommend a Market Rule power factor amendment as the measured power factor is due to the connected DG and asks that a case by case review be conducted when the power factor consistently does not meet the Market Rule requirement.

7.2.2 Bruce HWP B TS

Power factor at Bruce HWP B TS is often low and does not meet IESO Market Rule requirements. As per section 6.2.3 of the Needs Assessment, the low power factor at Bruce HWP B TS is to be managed by the transmitter and the affected customer.

Recommended Plan

The power factor review conducted by the Local Planning working group, showed that while the power factor of the load occasionally (rather than often as previously identified) does not meet Market Rule requirements there is no negative effect at this time. The investigation is detailed in the Local Planning report [4]. The Local Plan recommends no mitigation is required at this time.

7.3 Customer Delivery Point Performance

7.3.1 Customers Supplied from Circuit 61M18

The performance of delivery points supplied from circuit 61M18, specifically Constance DS and Goderich TS were reviewed. The review is summarized in Appendix F, section F.1.

Recommended Plan and Current Status

To address delivery point performance to Constance DS and Goderich TS, it is recommended that Hydro One Transmission continue to rely on its line and station maintenance programs, as well as capital sustainment projects listed in section 4.0 and in Table 7-1 to improve the overall reliability.

Current Status of Sustainment Work associated 61M18 Delivery Points

The 17 remaining original 1959 structures on circuit 61M18 along with 11 other structures are schedule to be tested over the next 2 years. Those that are determined to be End-Of-Life (in poor condition), will then be replaced in the next 5 years. These replacements will occur under Hydro One's Line Sustainment programs.

7.3.2 Customers Supplied from Circuit L7S

The performance of delivery points supplied from circuit L7S, specifically Centralia TS, Grand Bend East DS, St. Marys TS and the 4 industrial customer connections, were reviewed. The review is summarized in Appendix F, section F.2.

Recommended Plan

To address delivery point performance, it is recommended that Hydro One Transmission undertake a staged approach. Stage 1 will entail a detailed field screening of the line for approximately $154 thousand in 2017. Based on findings from the field screening, work to reduce the frequency of interruptions due to adverse weather should be implemented in 2018 and 2019. Cost for improvements is unknown at this time as it is dependent on actual findings. Performance will then be monitored for 2-3 years to verify improvement. Stage 2 will be based on the monitored performance and may entail strategically installing 115 kV in-line remotely-operated switches on circuit L7S to reduce the duration of interruptions. Switches are currently estimated to cost between $1M to $4M depending on the number of switches and their location. Funding of the staged plan to be as per the OEB-approved Hydro One Customer Delivery Point Performance Standard [EB-2002-0424, updated February 7, 2008]. Capital contribution from customers is not anticipated at this time. If, however, capital contribution is required from customers such financial obligation will be determined using methodology set out in the Transmission System Code.

7.3.3 Customers Supplied from Circuit D10H

The performance of delivery points supplied solely from circuit D10H, specifically Palmerston TS and Elmira TS were reviewed. The review is summarized in Appendix F, section F.3.

Current Status

Consultations with customers supplied from D10H are expected to be undertaken in 2017. Additional assessment and/or infrastructure to adhere to the OEB-approved funding rules for customer delivery point reliability improvements. Improvements may entail installing 115 kV in-line remotely operated switches for approximately $1.5M. Funding of the staged plan to be as per the OEB-approved Hydro One Customer Delivery Point Performance Standard [EB-2002-0424, updated February 7, 2008]. Capital contribution might be required from customers and such financial obligation will be determined using methodology set out in the Transmission System Code.

7.4 Step-Down Transformation Capacity

7.4.1 Hydro One Distribution

The RIP load forecast in conjunction with more recent requests for step-down transformation capacity by Hydro One Distribution at Douglas Point TS indicates that additional step-down transformation capacity is needed.

Current Status

Hydro One Distribution is currently working with its customer to determine their connection capacity requirements, size and timeline. Once the customer's requirements are firm, one of the three "need" scenarios outlined in section 6.4 of this report will be undertaken.

7.5 Transmission Sustainment Plans

As part of Hydro One's transmitter requirements, Hydro One continues to ensure a reliable transmission system by carrying out maintenance programs as well as periodic replacement of equipment based on their condition. Table 7.1 lists Hydro One's major transmission sustainment *projects* in the Region that are currently planned or underway. There is currently no major line sustainment *projects* planned within the next 5 years. Maintenance *programs* such as insulator, shield wire, structure replacements will continue to be carried out in the Region as required based on equipment/asset condition assessments.

Table 7-1: Hydro One Transmission Major Sustainment Initiatives[2]

Station	General Description of Work	Planning In Service Date
Bruce A TS	• Replacement of 230 kV circuit breakers • Uprating of the station strain buses • Replacement of Protections and Control relay building	2019
	• Replacement of 500 kV circuit breakers and switches • Replacement of 2 autotransformers 500/230 kV • Upgrading of Protection and Control equipment	2025
Bruce B SS	• Replacement of 500 kV circuit breakers and switches	2021

[2] Scope and dates as of July 2017 and are subject to change

Centralia TS	• Replace existing 3 transformers with a typical 25/42 MVA 2 transformer arrangement • Replacement of 27.6 kV switchyard • Installation of new PCT Facilities	2019
Detweiler TS	• Replacement of AC and DC station service	2018
	• Replacement of T2 and T4 autotransformers and upgrade to spill containment • Replacement Protection and Control equipment	2021
Hanover TS	• Replacement of T1/T2 transformers and associated switches • Replacement of low voltage circuit breakers and switches • Replacement of Protection and Control systems and CVT's *Additional scope of work currently under development*	2023
Palmerston TS	• Replace existing 3 transformers with a typical 50/83 MVA 2 transformer arrangement. • Replacement of low voltage switches • Replacement of Protection and Control systems with new PCT facilities • Upgrade to AC & DC station services	2019
Seaforth TS	• Replacement of 2 autotransformers 230/115 kV • Replacement of 2 step-down transformers 115/27.6 kV • Replacement of 230kV switches • Upgrade Protection and Control systems • Updated AC & DC station service	2023
Wingham TS	• Complete station refurbishment *Additional scope of work currently under development*	2022

Based on the needs identified in the region thus far and the transmission sustainment plans listed in Table 7-1, consolidation of sustainment and development needs is not necessary at this time.

8. CONCLUSION

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GREATER BRUCE-HURON REGION.

Five near and mid-term needs were identified for the Greater Bruce-Huron Region. They are:

I. Transmission Circuit Capacity on L7S

II. Low power factor at Wingham TS

III. Low power factor at Bruce HWB TS

IV. Customer delivery point performance review on the 115 kV system

V. Step-down transformation capacity at Douglas Point TS

This RIP report addresses all five of these needs and has concluded that no regional plans for needs I, II and III are required at this time. Next Steps, Lead Responsibility, and Timeframes for implementing the regional plans needs IV and V are summarized in the Table 8-1 below.

Table 8-1: Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	In-Service Date	Cost	Needs Mitigated
1	Improve 3L7S Delivery Point Performance	2 Stage Plan	Hydro One Transmission	2017-2023	$154k - TBD	IV
2	Accommodation for Connection Capacity Requests near Kincardine– Hydro One Network Inc. Distribution	Await Customer Direction	Hydro One Distribution	TBD	TBD	V

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1] Hydro One, "Needs Assessment Report, Greater Bruce-Huron Region", 6 May 2016. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Needs%20Assessment%20Report%20-%20GreaterBruce-Huron%20Region.pdf

[2] Hydro One, "Local Planning Report – Low Power Factor at Wingham TS Assessment", 18 October 2016. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Local%20Planning%20Report%20-%20Wingham%20TS%20Power%20Factor%20Assessment.pdf

[3] Hydro One, "Local Planning Report – L7S Thermal Overload", 14 November 2016. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Local%20Planning%20Report%20-%20L7S%20Thermal%20Overload.pdf

[4] Hydro One, "Local Planning Report – Low TS Power Factor at Bruce heavy Water B TS Assessment", 12 May 2017. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Bruce%20HWB%20TS%20Power%20Factor%20Assessment%20-%20FINAL.PDF

APPENDIX A: STEP-DOWN TRANSFORMER STATIONS IN THE GREATER BRUCE-HURON REGION

Station	Voltage (kV)	Supply Circuits
Bruce HWP B TS	230 kV	B20P/B24P
Douglas Point TS	230 kV	B20P/B24P
Hanover TS	115 kV	B4V/B5V
Owen Sound TS	230 kV	B27S/B28S
Seaforth TS	115 kV	B22D/B23D
Stratford TS	230 kV	B22D/B23D
Wingham TS	230 kV	B22D/B23D
Festival MTS #1	230 kV	B22D/B23D
Palmerston TS	115 kV	D10H
Goderich TS	115 kV	61M18
Constance DS	115 kV	61M18
St. Marys TS	115 kV	L7S
Customer CTS #1	115 kV	L7S
Centralia TS	115 kV	L7S
Grand Bend East DS	115 kV	L7S
Customer CTS #2	115 kV	L7S
Customer CTS #3	115 kV	L7S
Customer CTS #4	115 kV	L7S

APPENDIX B: REGIONAL TRANSMISSION CIRCUITS IN THE GREATER BRUCE-HURON REGION

Location	Circuit Designation	Voltage (kV)
Bruce A TS - Orangeville TS	B4V/B5V	230 kV
Bruce A TS - Detweiler TS	B22D/ B23D	230 kV
Bruce A TS - Owen Sound TS	B27S/B28S	230 kV
Bruce A TS - Douglas Point TS	B20P/B24P	230 kV
Hanover TS – Palmerston TS	D10H-North	115 kV
Seaforth TS - Goderich TS	61M18	115 kV
Seaforth TS - St. Marys TS	L7S	115 kV
Owen Sound TS – Hanover TS	S1H	115 kV

APPENDIX C: DISTRIBUTORS IN THE GREATER BRUCE-HURON REGION

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc.	Constance	Tx
	Centralia TS	Dx
	Grand Bend East DS	Tx
	Douglas Point TS	Dx
	Goderich TS	Dx
	Hanover TS	Dx
	Owen Sound TS	Dx
	Palmerston TS	Dx
	Seaforth TS	Dx
	St. Marys TS	Dx
	Stratford TS	Dx
	Wingham TS	Dx
Erie Thames Power Lines Corporation	Constance DS	Dx
Festival Hydro Inc.	Grand Bend East DS	Dx
	Seaforth TS	Dx
	Stratford TS	Dx
	Festival MTS #1	Tx
Lake Huron Primary Water Supply System	Lake Huron WTP CTS	Tx
Lake Huron Primary Water Supply System	McGillivray R&BP CTS	Tx
West Coast Huron Energy Inc.	Goderich TS	Tx
Enbridge Pipeline Inc.	Enbridge Bryanston CTS	Tx
St. Marys Cement Inc.	St. Marys Cement CTS	Tx

APPENDIX D: REGIONAL LOAD FORECAST (2016-2025)

Table D-1: Gross – Winter Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.87	33.40	33.77	34.25	34.87	35.48	35.93	36.36	36.77	37.19
Constance DS	17.68	17.76	17.79	17.87	18.01	18.16	18.26	18.35	18.46	18.57
Douglas Point TS*	73.44	74.42	83.75	92.21	93.41	94.66	95.80	96.95	98.14	99.39
Customer CTS #1	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.41	19.55	19.70	19.85	20.00	20.15	20.30	20.45	20.60	20.76
Goderich TS	36.35	36.50	36.59	36.73	36.92	37.11	37.25	37.37	37.49	37.61
Grand Bend East DS	14.22	14.36	14.43	14.55	14.72	14.89	15.00	15.09	15.19	15.28
Hanover TS	102.37	103.16	103.93	104.95	105.99	107.05	107.73	108.39	109.06	109.72
Customer CTS #2	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	61.92	62.92	63.88	65.12	66.22	67.44	68.42	69.41	70.41	71.40
Seaforth TS*	33.44	33.65	37.25	33.62	33.87	34.12	34.28	34.44	34.59	34.74
Customer CTS #4	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.64
St. Marys TS	23.74	25.04	25.17	25.31	25.50	25.69	25.84	25.98	26.12	26.25
Stratford TS*	80.14	80.81	81.39	85.46	86.20	86.93	87.56	88.18	88.79	89.41
Wingham TS	48.99	49.80	50.44	51.23	52.24	53.24	54.07	54.89	55.74	56.62
Bruce HWB TS	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

*Updated March 2017 for RIP

Table D-2: Gross – Summer Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.42	32.73	33.15	33.78	34.40	34.83	35.24	35.65	36.05	36.45
Constance DS	15.56	15.57	15.63	15.76	15.90	15.98	16.07	16.16	16.26	16.36
Douglas Point TS*	47.40	47.40	63.29	63.76	64.26	64.64	65.03	65.41	65.78	66.18
Customer CTS #1	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	25.03	25.22	25.41	25.60	25.79	25.98	26.18	26.37	26.57	26.77
Goderich TS	39.08	39.15	39.27	39.48	39.68	39.81	39.93	40.06	40.18	40.31
Grand Bend East DS	16.44	16.50	16.62	16.84	17.05	17.17	17.29	17.39	17.50	17.61
Hanover TS	76.71	76.94	77.62	78.60	79.25	79.71	80.12	80.53	80.93	81.32
Customer CTS #2	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
Customer CTS #3	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	97.58	98.48	99.75	101.70	103.59	104.89	106.11	107.31	108.48	109.63
Palmerston TS	53.07	53.79	54.90	56.36	57.68	58.81	59.97	61.19	62.43	63.75
Seaforth TS*	30.68	34.34	30.56	30.78	30.99	31.14	31.27	30.78	31.54	31.67
Customer CTS #4	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.31	25.42	25.57	25.75	25.94	26.09	26.24	26.38	26.52	26.66
Stratford TS*	78.09	78.59	82.38	83.14	83.91	84.52	85.11	85.70	86.29	86.88
Wingham TS	37.99	38.11	38.36	38.87	39.37	39.67	39.97	40.26	40.54	40.83
Bruce HWB TS	5.14	5.24	5.34	5.44	5.54	5.64	5.74	5.84	5.93	6.03

*Updated March 2017 for RIP

Table D-3: Gross – Winter Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	34.15	34.70	35.08	35.59	36.23	36.87	37.33	37.77	38.21	38.63
Constance DS	19.42	19.51	19.54	19.63	19.79	19.95	20.06	20.17	20.28	20.40
Douglas Point TS*	73.44	74.42	83.75	92.21	93.41	94.66	95.80	96.95	98.14	99.39
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	25.47	25.66	25.85	26.05	26.24	26.44	26.64	26.84	27.04	27.24
Goderich TS	41.61	41.78	41.88	42.04	42.26	42.48	42.63	42.77	42.91	43.05
Grand Bend East DS	14.75	14.89	14.97	15.09	15.27	15.45	15.56	15.66	15.75	15.85
Hanover TS	96.65**	97.40	98.12	99.09	100.07	101.06	101.71	102.33	102.97	103.58
Customer CTS #2	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90
Customer CTS #3	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
Owen Sound TS	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	68.03**	69.12	70.18	71.54	72.76	74.10	75.17	76.26	77.36	78.45
Seaforth TS*	34.75	34.96	38.70	34.92	35.19	35.44	35.62	35.78	35.93	36.09
Customer CTS #4	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	25.13	26.50	26.64	26.79	26.99	27.19	27.35	27.50	27.64	27.78
Stratford TS*	84.52	85.23	85.84	90.13	90.91	91.69	92.36	93.00	93.65	94.30
Wingham TS	57.98	58.94	59.70	60.63	61.82	63.01	63.98	64.96	65.96	67.00
Bruce HWB TS	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Updated March 2017 for RIP

**Load Transfer from Hanover TS to Palmerston TS

Table D-4: Gross – Summer Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	34.23	34.56	35.01	35.67	36.32	36.78	37.22	37.64	38.07	38.49
Constance DS	17.78	17.79	17.86	18.01	18.17	18.27	18.36	18.47	18.58	18.70
Douglas Point TS*	48.06	48.06	64.17	64.65	65.15	65.54	65.93	66.32	66.69	67.10
Customer CTS #1	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	28.11	28.32	28.53	28.74	28.96	29.18	29.39	29.61	29.84	30.06
Goderich TS	40.71	40.78	40.91	41.12	41.33	41.46	41.59	41.72	41.85	41.98
Grand Bend East DS	18.88	18.95	19.09	19.34	19.58	19.72	19.85	19.98	20.10	20.22
Hanover TS	75.61**	75.84	76.50	77.47	78.12	78.57	78.97	79.37	79.77	80.15
Customer CTS #2	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Customer CTS #3	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
Owen Sound TS	101.31	102.25	103.57	105.59	107.55	108.90	110.17	111.41	112.63	113.82
Palmerston TS	54.71**	55.45	56.60	58.10	59.46	60.63	61.82	63.07	64.36	65.72
Seaforth TS*	31.00	34.70	30.87	31.10	31.31	31.46	31.59	31.10	31.86	31.99
Customer CTS #4	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	26.05	26.17	26.31	26.51	26.70	26.86	27.01	27.16	27.30	27.44
Stratford TS*	88.42	88.99	93.28	94.15	95.01	95.70	96.38	97.05	97.71	98.37
Wingham TS	54.05	54.21	54.58	55.29	56.00	56.43	56.86	57.27	57.67	58.08
Bruce HWB TS	6.54	6.66	6.79	6.91	7.04	7.16	7.29	7.42	7.54	7.67

*Updated March 2017 for RIP

**Load Transfer from Hanover TS to Palmerston TS

Table D-5: Net – Winter Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.65	32.92	32.96	33.16	33.52	33.90	34.16	34.45	34.69	34.94
Constance DS	17.57	17.55	17.41	17.35	17.36	17.40	17.41	17.44	17.46	17.50
Douglas Point TS*	72.99	73.55	81.97	89.53	90.03	90.70	91.34	92.11	92.84	93.64
Customer CTS #1	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.29	19.33	19.29	19.27	19.28	19.31	19.36	19.43	19.49	19.56
Goderich TS	36.12	36.07	35.81	35.65	35.58	35.55	35.50	35.49	35.45	35.43
Grand Bend East DS	14.13	14.19	14.13	14.13	14.19	14.27	14.30	14.34	14.37	14.39
Hanover TS	101.72	101.94	101.69	101.76	102.01	102.42	102.56	102.84	103.02	103.23
Customer CTS #2	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	61.53	62.17	62.50	63.20	63.80	64.60	65.20	65.92	66.58	67.25
Seaforth TS*	33.24	33.26	36.45	32.63	32.64	32.68	32.68	32.72	32.71	32.72
Customer CTS #4	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.65
St. Marys TS	23.59	24.75	24.63	24.57	24.58	24.61	24.63	24.68	24.70	24.73
Stratford TS*	79.65	79.87	79.65	82.97	83.08	83.29	83.48	83.78	83.99	84.23
Wingham TS	48.70	49.23	49.38	49.75	50.36	51.02	51.55	52.16	52.73	53.35
Bruce HWB TS	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

*Updated March 2017 for RIP

Table D-6: Net – Summer Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.04	31.57	31.62	31.89	32.20	32.42	32.61	32.85	33.05	33.25
Constance DS	15.45	15.35	15.23	15.20	15.20	15.19	15.18	15.20	15.22	15.24
Douglas Point TS*	47.00	46.67	61.64	61.45	61.39	61.39	61.38	61.49	61.50	61.58
Customer CTS #1	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	24.85	24.86	24.77	24.69	24.66	24.70	24.74	24.82	24.87	24.93
Goderich TS	38.70	38.50	38.18	37.98	37.84	37.74	37.63	37.59	37.50	37.43
Grand Bend East DS	16.32	16.27	16.20	16.24	16.31	16.33	16.33	16.37	16.38	16.40
Hanover TS	75.82	75.51	75.32	75.37	75.34	75.33	75.25	75.32	75.30	75.29
Customer CTS #2	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
Customer CTS #3	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	96.71	96.49	96.54	97.40	98.36	99.01	99.56	100.27	100.83	101.40
Palmerston TS	52.48	52.81	53.30	54.15	54.94	55.69	56.45	57.35	58.21	59.16
Seaforth TS*	30.39	33.79	29.72	29.62	29.57	29.53	29.48	28.89	29.45	29.42
Customer CTS #4	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.07	25.01	24.87	24.79	24.76	24.75	24.74	24.77	24.77	24.78
Stratford TS*	77.42	77.37	80.20	80.09	80.13	80.23	80.31	80.53	80.65	80.80
Wingham TS	37.72	37.57	37.40	37.49	37.65	37.71	37.76	37.88	37.94	38.03
Bruce HWB TS	5.06	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12

*Updated March 2017 for RIP

Table D-7: Net – Winter Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	33.93	34.20	34.24	34.46	34.82	35.23	35.50	35.79	36.05	36.31
Constance DS	18.62	18.61	18.45	18.39	18.40	18.44	18.45	18.48	18.51	18.55
Douglas Point TS*	72.99	73.55	81.97	89.53	90.03	90.70	91.34	92.11	92.84	93.64
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	23.83	23.87	23.82	23.80	23.81	23.84	23.90	24.00	24.07	24.16
Goderich TS	40.85	40.79	40.49	40.32	40.23	40.20	40.15	40.14	40.09	40.06
Grand Bend East DS	14.66	14.72	14.65	14.65	14.72	14.81	14.84	14.88	14.90	14.93
Hanover TS	102.77*	102.99	102.75	102.81	103.07	103.48	103.63	103.90	104.09	104.30
Customer CTS #2	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90
Customer CTS #3	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
Owen Sound TS	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	62.06*	62.70	63.04	63.75	64.36	65.15	65.77	66.49	67.16	67.83
Seaforth TS*	33.66	33.68	36.92	33.05	33.05	33.10	33.09	33.13	33.13	33.14
Customer CTS #4	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	24.97	26.19	26.07	26.01	26.01	26.04	26.07	26.12	26.14	26.17
Stratford TS*	83.99	84.23	84.00	87.49	87.61	87.83	88.03	88.34	88.57	88.83
Wingham TS	57.64	58.26	58.44	58.87	59.59	60.38	61.01	61.73	62.41	63.14
Bruce HWB TS	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Updated March 2017 for RIP

Table D-8: Net – Summer Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Centralia TS	33.84	33.38	33.43	33.72	34.04	34.27	34.47	34.72	34.93	35.15
Constance DS	17.66	17.54	17.41	17.37	17.38	17.36	17.35	17.38	17.39	17.42
Douglas Point TS	47.66	47.32	62.49	62.30	62.24	62.24	62.23	62.35	62.36	62.44
Customer CTS #1	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	27.91	27.92	27.81	27.73	27.69	27.74	27.77	27.87	27.93	28.00
Goderich TS	39.02	38.81	38.49	38.29	38.15	38.05	37.93	37.89	37.81	37.74
Grand Bend East DS	18.75	18.68	18.61	18.65	18.73	18.75	18.76	18.80	18.81	18.83
Hanover TS	75.82	75.51	75.32	75.37	75.34	75.33	75.25	75.32	75.30	75.29
Customer CTS #2	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Customer CTS #3	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
Owen Sound TS	100.41	100.21	100.26	101.16	102.15	102.82	103.40	104.13	104.72	105.31
Palmerston TS	52.80	53.13	53.63	54.48	55.27	56.03	56.79	57.70	58.57	59.52
Seaforth TS	30.39	33.79	29.72	29.62	29.57	29.53	29.48	28.89	29.45	29.42
Customer CTS #4	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	25.81	25.74	25.60	25.52	25.49	25.48	25.47	25.50	25.50	25.50
Stratford TS	86.73	86.68	89.84	89.72	89.77	89.88	89.97	90.21	90.35	90.52
Wingham TS	50.79	50.58	50.35	50.48	50.69	50.77	50.84	51.00	51.08	51.20
Bruce HWB TS	9.83	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95

*Updated March 2017 for RIP

APPENDIX E: RIP TRANSMISSION ADEQUACY ASSESSMENT

This table assesses the impact of the updated March 2017 RIP load forecast based on the original findings of the May 2016 Needs Assessment.

Change in Load Forecast	Seaforth TS			Stratford TS			Douglas Point TS		
		Coincident MW	Non-Coincident MW		Coincident MW	Non-Coincident MW		Coincident MW	Non-Coincident MW
Red font indicates an increase in forecasted load from the Needs Assessment.	summer: 2025 Gross	31.67	31.67	summer: 2025 Gross	86.88	98.37	summer: new 2025 Gross	66.18	67.1
	summer: 2025 Net	29.42	29.42	summer: 2025 Net	80.8	90.52	summer: new 2025 Net	61.58	62.44
	summer 10 Day LTR	39.3 MW		summer 10 Day LTR	104.4 MW		summer 10 Day LTR	87.5 MVA	
Green font indicates a reduction in forecasted load from the Needs Assessment.	winter: new 2025 Gross	34.74	36.09	winter: new 2025 Gross	89.41	94.3	winter: new 2025 Gross	99.39	99.39
	winter: new 2025 Net	32.72	33.14	winter: new 2025 Net	84.23	88.83	winter: new 2025 Net	93.64	93.64
	winter 10 Day LTR	49.9 MW		winter 10 Day LTR	115.7 MW		winter 10 Day LTR	98.8 MW	

	Seaforth TS	Stratford TS	Douglas Point TS
Historical Power Factor	N/A	N/A	N/A
Load Security	no negative impact	no negative impact	no negative impact
Load Restoration	no negative impact	no negative impact	no negative impact
Voltage Performance	no negative impact	no negative impact	no negative impact
CDPP	N/A	N/A	N/A
230/115 kV Autos	no negative impact	no negative impact	no negative impact
230 kV Lines	no negative impact	no negative impact	no negative impact
115 kV Lines	no negative impact	no negative impact	no negative impact
Step down Transformation Capacity	no negative impact	Study shows that there is a slight impact but loading remains within LTR and at least one LV cap must be in-service during summer loading by the end of the study period. This is similar to the Needs Assessment results.	Study shows that the gross winter forecast loading is at the LTR in winter 2023/2024. All summer forecasts show loading is within LTR for the study period.
Bulk System Performance	no negative impact	no negative impact	no negative impact

APPENDIX F: CUSTOMER DELIVERY POINT PERFORMANCE REVIEW

Based on the recommendations from the May 2016 Needs Assessment, 15 customer delivery points were reviewed in detail to assess their reliability performance. Reliability performance of a delivery point is a measure of the frequency of interruption and duration of interruption. The yearly frequency and yearly total duration of interruptions are compared against Hydro One performance standards filed with the OEB, [EB-2002-0424, updated February 7, 2008].

All 15 delivery points are supplied solely from single circuit 115 kV transmission lines and are grouped as follows:

Table F-1 - Customer Delivery Points

Single circuit 115 kV Transmission Line	Station	# of Customer Delivery Points
61M18	Goderich TS	2
	Constance DS	1
L7S	Centralia TS	2
	Grand Bend East DS	1
	St. Mary TS	1
	Industrial Customer # 1	1
	Industrial Customer # 2	1
	Industrial Customer # 3	1
	Industrial Customer # 4	1
D10H -North	Palmerston TS	2
D10H - South	Elmira TS	2

The reliability performance of the delivery points were studied in groups based on their connection point to the transmission system, specifically their 115 kV transmission line supply as shown in Table F-1.

The review of each delivery point included a 10 year review of interruptions between years 2006 and 2015. The interruptions were compared against each delivery points "Group" metrics as defined in the OEB filing as well as each delivery points "Individual Historical Performance" as defined in the OEB filing. Where the yearly performance did not meet either the Group or Individual standards for either frequency or duration of interruptions, Hydro One Transmission classified the delivery point as an "Outlier". Based on a delivery point's Outlier status, their reliability performance is reviewed. The summary of review is given below.

F.1 Delivery Points Supplied by Transmission Line 61M18

In the past, 2006-2010, Goderich TS was classified as a Group Outlier for both frequency and duration of interruption. Recently it is classified as a Group Outlier for duration only. These classifications are mainly due to past equipment failures at Seaforth TS and recently as a consequence of line 61M18 tied to line L7S while L7S experienced interruptions.

Constance DS is not classified as a Group Outlier; however it is occasionally classified as an Individual Outlier for duration of interruption. Although Constance DS is subject to the same line 61M18 interruptions as Goderich TS, it is typically not classified as a Group Outlier because it has less stringent performance metrics due to the smaller amount of load (MW) supplied from it.

The review showed that the root cause of interruptions is due to the performance of the transmission line 61M18 during adverse weather. When 61M18 is interrupted, all load connected to Constance DS and Goderich TS is left unsupplied. As line 61M18 is radial, there are not many options to resupply the load prior to repairing the line. Often building a temporary bypass can take longer than fixing the damaged equipment and the ability to transfer the load to other stations is limited due to the sparse topology of customer distribution systems. Overall, customers supplied from Constance DS and Goderich TS have similar delivery point performance compared to other customers supplied by a single radial circuit and poor delivery point performance compared to other customers supplied by dual circuits. Additionally, a technical review concluded that the transmission line is performing as originally designed with respect to line design security parameters which correspond to a line’s susceptibility to faults caused by external forces such as lightning and storms.

As upgrading the transmission supply to these stations is not economical for neither the customers nor Hydro One Transmission based on the OEB-approved funding rules for customer delivery point reliability improvement, it is recommended for Hydro One Transmission to continue to rely on its Line and Station maintenance and capital sustainment projects to improve the overall reliability performance to delivery points. Based on customer consultations, Goderich Hydro - West Coast Huron Energy Inc., Erie Thames Power and Hydro One Distribution have agreed to this approach and will continue to monitor performance.

F.2 Delivery Points Supplied by Transmission Line L7S

Centralia TS is classified as a Group Outlier for both frequency and duration of interruption. Recently in 2013 and 2014 is has also been classified as an Individual Outlier for duration of interruption.

Grand Bend East DS is classified as a Group Outlier for both frequency (occasionally) and duration (consistently) of interruption, as well as an Individual Outlier for duration.

All four industrial customer delivery points are occasionally classified at a Group Outlier for frequency of interruption; while one of them often is classified as a Group Outlier for duration of interruption. Over the past 3 years, the industrial customer delivery points have often been classified as Individual Outliers for duration.

The review showed that the root cause of interruptions is due to the performance of the transmission line L7S during adverse weather. When L7S is interrupted, all load connected to it is left unsupplied. As line L7S is radial, there are not many options to resupply the load prior to repairing the line. Often building a temporary bypass can take longer than fixing the damaged equipment and the ability to transfer the load to other stations is limited due to the sparse topology of customer distribution systems. Depending on prevailing system conditions, manual switching on the transmission system can be performed to resupply some L7S load from Detweiler TS via 115 kV circuit D8S. Overall, customers supplied from L7S have similar delivery point performance compared to other customers supplied by a single radial circuit and poor delivery point performance compared to other customers supplied by dual circuits. Additionally, a technical review concluded that the transmission line is performing as originally designed with respect to line design security parameters which correspond to a line's susceptibility to faults caused by external forces such as lightning and storms.

Due to the Individual Outlier classification of delivery points supplied from L7S it is recommended that a focused line assessment is undertaken. Although major upgrades to the transmission supply is not economical for neither the customers nor Hydro One Transmission based on the OEB-approved funding rules for customer delivery point reliability improvement, it remains the recommendation for Hydro One Transmission to improve the reliability of transmission line L7S. A two stage approach is prudent. Stage 1 will entail a detailed field screening of the line for approximately $154 k in 2017. Based on findings from the field screening, work to reduce the frequency of interruptions due to adverse weather should be implemented in 2018 and 2019. Cost for improvements is unknown at this time as it is dependent on actual findings. Performance will then be monitored for 2-3 years to verify improvement. It is expected that reduction to the frequency of interruptions will reduce the total duration of interruptions. Stage 2 will be based on the monitored performance and may entail strategically installing 115 kV in-line remotely-operated switches to reduce the duration of interruptions. Switches are currently estimated to cost between $1M to $4M depending on the number of switches and their location.

Based on customer consultations, Festival Hydro, Hydro One Distribution and the industrial customers have agreed to this approach.

F.3 Delivery Points Supplied by Transmission Line D10H

115 kV circuit D10H between Detweiler TS and Hanover TS is operated normally-open at Palmerston TS whereby Palmerston TS is normally supplied from Hanover TS (D10H-North) while Elmira TS is normally supplied from Detweiler TS (D01H – South).

Over the past 3 years, Palmerston TS has been classified as a Group Outlier for both frequency and duration of interruption. It has not been classified as an Individual Outlier over the 10 year review period.

Over the past 3 years, Elmira TS has been classified as a Group Outlier for both frequency and duration of interruption. It has been classified as an Individual Outlier once in the 10 year review period; specifically in 2013 for frequency of interruption.

The review showed that the root cause of interruptions is due to the performance of the transmission lines D10H-North and D10H-South during adverse weather. When D10H-North is interrupted, all load connected to Palmerston TS is left unsupplied. When D10H-South is interrupted, all load connected to Elmira TS is left unsupplied. Since there are several 115 kV in-line switches along D10H and depending on prevailing system conditions, circuit D10H can be reconfigured to supply Palmerston TS and Elmira TS from either the Hanover TS or Detweiler TS ends. 115 kV in-line switches at Palmerston TS have the capability to be operated remotely. There are two other manual-operated switches surrounding the tap to Elmira TS.

Overall, customers supplied from Palmerston TS and Elmira TS have similar delivery point performance compared to other customers supplied by a single radial circuit and poor delivery point performance comparable to other customers supplied by dual circuits. Additionally, a technical review concluded that the transmission line is performing as originally designed with respect to line design security parameters which correspond to a line’s susceptibility to faults caused by external forces such as lightning and storms.

Consultations with customers supplied from D10H are expected to be undertaken in 2017. Additional assessment and/or infrastructure to adhere to the OEB-approved funding rules for customer delivery point reliability improvements. Improvements may entail installing 115 kV in-line remotely operated switches for approximately $1.5M.

APPENDIX G: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Hydro One Networks Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345.5420
Ajay.Garg@HydroOne.com

Niagara
Regional Infrastructure Plan ("RIP")

March 28th 2017

Canadian Niagara Power Inc.
Grimsby Power Inc.
Alectra Utilities
Hydro One Networks Inc. (Distribution)
Niagara Peninsula Energy Inc.
Niagara-On-the-Lake Hydro Inc.
Welland Hydro-Electric System Corporation

The Niagara Region includes the municipalities of 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 Town of Pelham.

The Needs Assessment ("NA") report for the Niagara Region was completed on April 30th, 2016 (see attached). The report concluded that there were only two needs in the Region and that they should be addressed as follows:

- Thermal overloading of 115kV circuit Q4N: Addressed in a Local Plan ("LP") report.

The loading constraints on 115kV circuit Q4N was addressed in a LP report led by Hydro One Networks Inc. and published on November 11th, 2016. The report concluded that Hydro One already has plans to replace the existing section of conductor between Sir Adam Beck SS #1 and Portal JCT with a 910A continuous rating conductor at 93°C as part of their Beck #1 SS Refurbishment project. The expected in-service date for this conduction section upgrade is December 2019.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the RIP for the Niagara Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2021) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks Inc.

[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: Niagara

Date: April 30th 2016

Prepared by: Niagara Region Study Team

Niagara Study Team
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

DISCLAIMER

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Niagara region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

Region	Niagara (the "Region")		
Lead	Hydro One Networks Inc. ("Hydro One")		
Start Date	October 15, 2015	End Date	April 30th 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Niagara Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the Niagara Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The Niagara Region belongs to Group 3. The NA for this Region was triggered on October 15, 2015 and was completed on April 30th 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2025. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the Niagara Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2015 to 2024). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. Transmission Lines & Ratings The 230kV and 115kV lines are adequate over the study period with a section of 115kV circuit Q4N being the exception.
B. 230 kV and 115 kV Connection Facilities The 230kV and 115kV connection facilities in this region are adequate over the study period.

System Reliability, Operation and Restoration Review

There are no known issues with system reliability, operation and restoration in the Niagara region.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following sustainment work is currently planned by Hydro One in the region:

- DeCew Falls SS: Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1: 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS: Switchgear Replacement (2020)
- Sir Adam Beck SS #2: 230kV Circuit Breakers Replacement (2020)
- Glendale TS: Station Refurbishment and Reconfiguration (2021)
- Stanley TS: Station Refurbishment (2021)
- Thorold TS: Transformer Replacement (2021)
- Crowland TS: Transformer Replacement (2021)

Based on the findings of the Needs Assessment, the study team recommends that thethermal overloading of 115kV circuit Q4N shouldbe further assessed as part of a Local Plan. No further regional coordination or planning is required.

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1 Introduction

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Niagara Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the Niagara Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain local type of needs if straight forward wires solutions can address a need. Ultimately, assessment and findings of the local plans are incorporated in the RIP for the region.

This report was prepared by the Niagara Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Niagara Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Canadian Niagara Power Inc.
4	Grimsby Power Inc.
5	Haldimand County Hydro Inc
6	Horizon Utilities Corp.
7	Hydro One Networks Inc. (Distribution)
8	Niagara Peninsula Energy Inc.
9	Niagara on the Lake Hydro Inc.
10	Welland Hydro Electric System Corp.

2 Regional Issue / Trigger

The NA for the Niagara Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Niagara Region belongs to Group 3.

3 Scope of Needs Assessment

This NA covers the Niagara Region over an assessment period of 2015 to 2024. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 Niagara Region Description and Connection Configuration

For regional planning purposes, 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 Town of Pelham. Haldimand County has also been included in the regional infrastructure planning needs assessment for Niagara region. A map of the region is shown below in Figure 1.

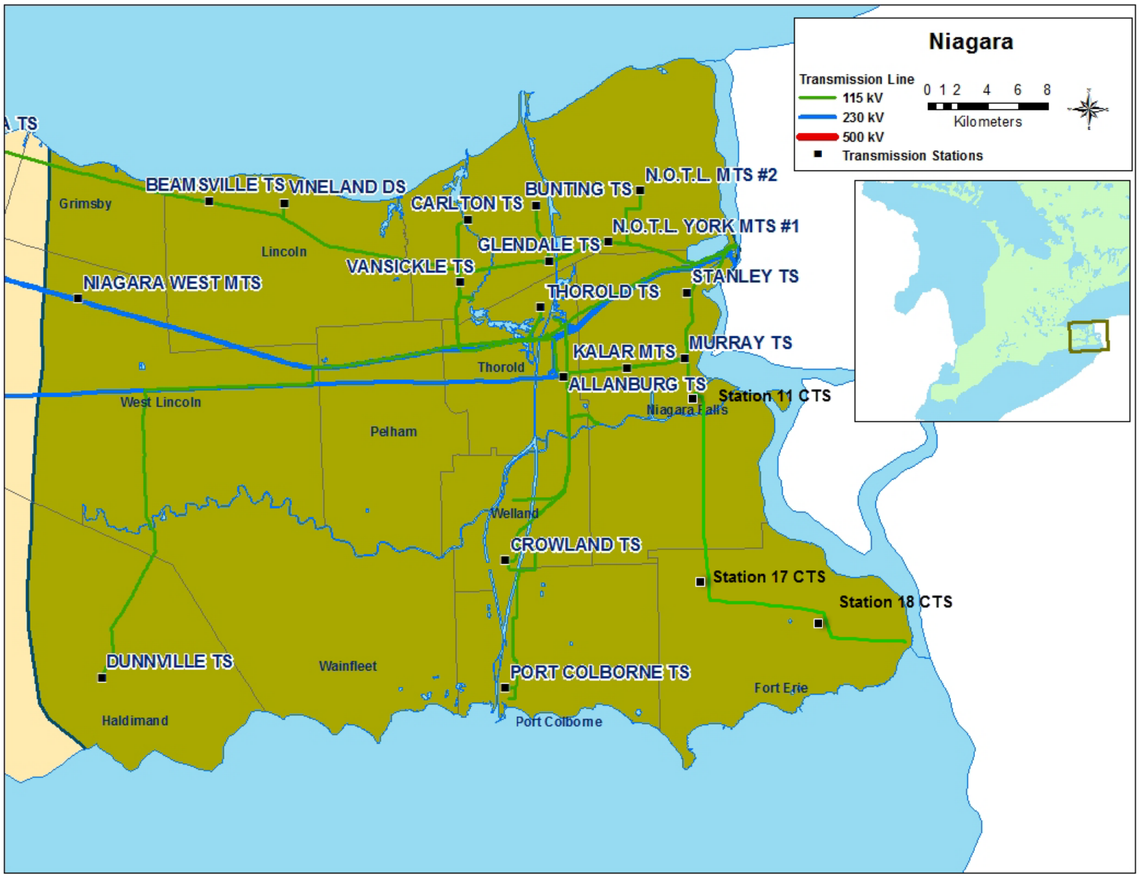

Figure 1: Niagara Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck #1, Sir Adam Beck #2, Decew Falls GS, Thorold GS and the autotransformers at Allanburg TS.

Bulk supply is provided through the 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS. These circuits connect this region to Hamilton/Burlington.

The Niagara Region has the following local distribution companies (LDC):

- Canadian Niagara Power Inc.
- Grimsby Power Inc.
- Haldimand County Hydro Inc.
- Horizon Utilities
- Hydro One Distribution Inc.
- Niagara Peninsula Energy Inc.
- Niagara on the Lake Hydro Inc.
- Welland Hydro Electric System Corporation

Large transmission connected customers in the area will not actively participate in the regional planning process, however their load forecasts will used in determining regional supply needs.

Table 2: Transmission Lines and Stations in Niagara Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Customer Transformer Stations
Q3N, Q4N, Q11S, Q12S, Q2AH, A36N, A37N, D9HS, D10S, D1A, D3A, A6C, A7C,C1P, C2P	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q21P, Q22P	Allanburg TS*, Stanley TS, Niagara Murray TS, Thorold TS, Vansickle TS, Carlton TS, Glendale TS, Bunting TS, Dunville TS, Vineland TS, Beamsville TS, Sir Adam Beck SS #1, Sir Adam Beck SS #2, Crowland TS, Port Colborne TS	Niagara on the Lake #1 and #2 MTS, CNPI Station 11 , CNPI Station 17, CNPI Station 18, Kalar MTS, Niagara West MTS

Stations with Autotransformers installed

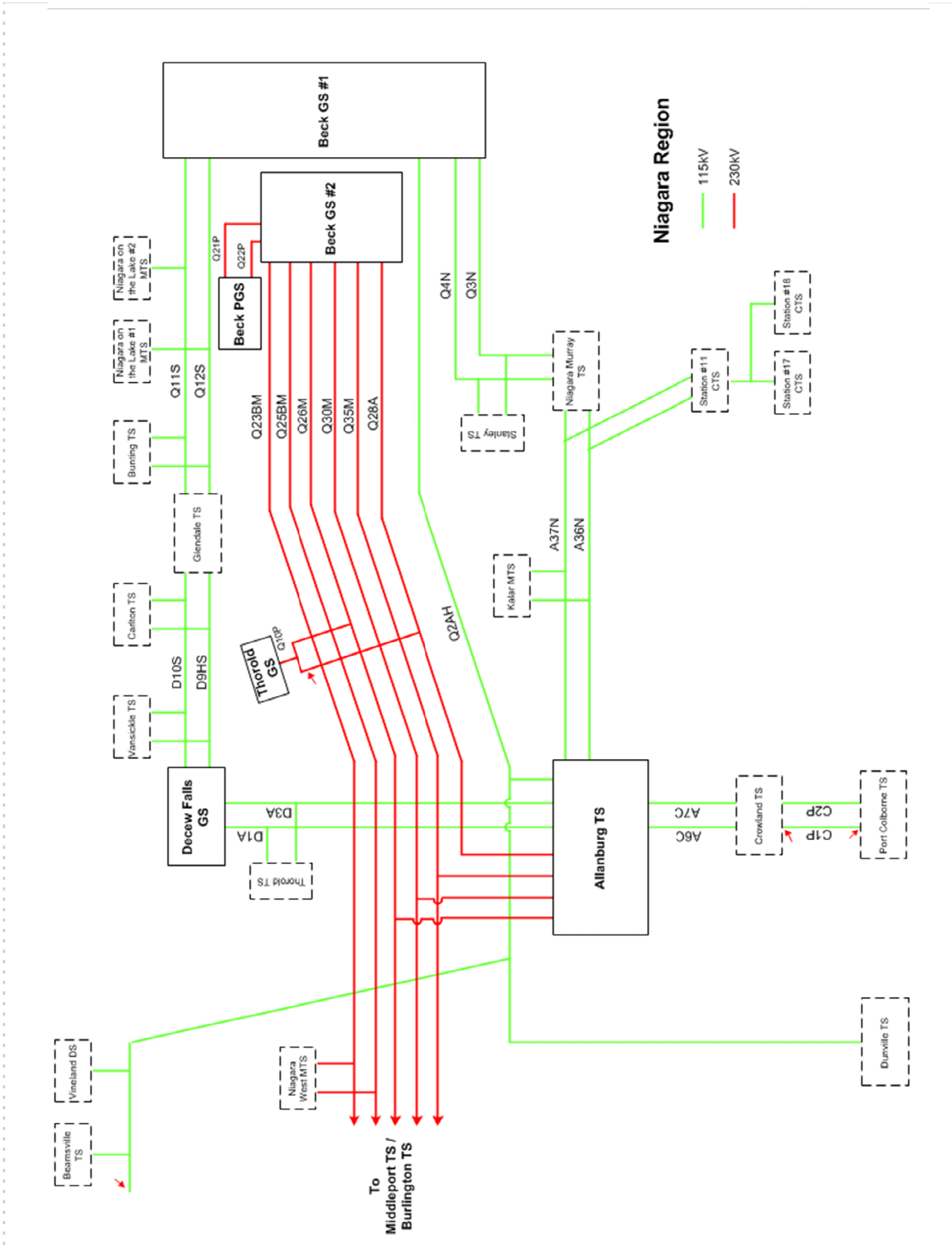

Figure 2: Simplified Niagara Regional Planning Electrical Diagram

4 Inputs and Data

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- Actual 2013 regional coincident peak load and station non-coincident peak load provided by IESO;
- Historical (2012-2014) net load and gross load forecast (2015-2024 provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by IESO;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.61% annually from 2015-2024.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to decrease at an average rate of approximately 0.26% annually from 2015-2024.

5 Needs Assessment Methodology

The following methodology and assumptions are made in this Needs Assessment:

1. The Region is summer peaking so this assessment is based on summer peak loads.
2. Forecast loads are provided by the Region's LDCs.
3. Load data for the industrial customers in the region were assumed to be consistent with historical loads.
4. Accounting for (2), (3), above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG are analyzed to determine if the needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report.

5. Review impact of any on-going and/or planned development projects in the Region during the study period.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR). Summer LTR ratings were reviewed to assess the worst possible loading scenario from a ratings perspective.
8. Extreme weather scenario factor at 1.037 was also assessed for capacity planning over the study term.
9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their summer long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using summer loading with summer 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.

- With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 Results

6.1 Transmission Capacity Needs

230/115 kV Autotransformers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

Transmission Lines & Ratings

The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

The 115 kV circuits supplying the Region are adequate over the study period with Q4N as an exception between Sir Adam Beck SS #1 x Portal Junction.

230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station summer peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario.

6.2 System Reliability, Operation and Restoration

6.2.1 Load Restoration

Load restoration is adequate in the area and meet the ORTAC load restoration criteria.

The needs assessment did not identify any additional issues with meeting load restoration as per the ORTAC load restoration criteria.

6.2.2 Thermal Overloading on Q4N Section

Under high generation scenarios at Sir Adam Beck GS #1, the loading on the *Beck SS #1 x Portal Junction* section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings. Hydro One already has plans to address this issue as part of the Beck SS #1 Refurbishment Project.

6.2.3 Power Factor at Thorold TS

A few instances (<54 hours / year) of power factor below 0.9 (between 0.89 - 0.9) were observed at the HV side of Thorold TS. Hydro One Distribution will investigate these instances and work with Distribution customers to address.

7 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers and power transformers during the study period. At this time, the following sustainment work is planned at the following stations:

- DeCew Falls SS Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS; Switchgear Replacement (2020)
- Sir Adam Beck SS #2 230kV Circuit Breakers Replacement (2020)
- Glendale TS; Station Refurbishment and Reconfiguration (2021)
- Stanley TS; Station Refurbishment (2021)
- Thorold TS; Transformer Replacement (2021)
- Crowland TS; Transformer Replacement (2021)

8 Recommendations

Based on the findings and discussion in Section 6 and 7 of this report, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

9 Next Steps

No further Regional Planning is required at this time. The Niagara Region Regional Planning will be reassessed during the next planning cycle or at any time should unforeseen conditions or needs warrant to initiate the regional planning for the region.

10 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

Appendix A: Non-Coincident Winter Peak Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
NPEI - Embedded	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
Grimsby Power, NPEI - Embedded	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
Hydro One, CNPI - Embedded	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Haldimand County Hydro	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
Hydro One - Embedded	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
NPEI - Embedded	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
NPEI Embedded	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland TS	Net Load Forecast	17.4	17.0	17.0										
Hydro One	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
NPEI - Embedded	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

LOCAL PLANNING REPORT

Q4N THERMAL OVERLOAD

Region: Niagara

Revision: Final
Date: November 11th 2016

Prepared by: Niagara Region Study Team

Niagara Region Local Planning Study Team
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Niagara Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Niagara Region ("Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	16 May 2016	**END DATE**	1 November 2016

1. INTRODUCTION

The purpose of this Local Planning ("LP") report is to develop and recommend a preferred wires solution that will address the local needs identified in the Needs Assessment (NA) report for the Niagara Region. The development of the LP report is in accordance with the regional planning process as set out in the Planning Process Working Group ("PPWG") Report to the Ontario Energy Board's ("OEB") and mandated by the Transmission System Code ("TSC") and Distribution System Code ("DSC").

2. LOCAL NEEDS REVIEWED IN THIS REPORT

This report reviewed the potential thermal rating violation for the Beck SS #1 x Portal Junction section of the 115kV Q4N circuit (egress out from Sir Adam Beck GS #1).

3. OPTIONS CONSIDERED

The following options were considered:

- Option 1: Status Quo
- Option 2: Uprate Circuit Section

4. PREFERRED SOLUTIONS

Option 2 is the preferred option. The uprating of limiting section of the circuit is included in Hydro One's Sustainment plan.

5. RECOMMENDATIONS

It is recommended that the circuit section upgrade proceed with current with an expected in-service date of December 2019.

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1 Introduction

The Needs Assessment (NA) for the Niagara Region ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. The NA for the Niagara Region was prepared jointly by the study team, including LDCs, Independent Electric System Operator (IESO) and Hydro One. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Region over the next ten years (2015 to 2024) and recommended that they should be further assessed through the transmitter-led Local Planning (LP) process.

As part of the NA report for the Niagara Region, it identified that under high generation scenarios at Sir Adam Beck GS #1, the loading on the Beck SS #1 x Portal Junction section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings in IESO's System Impact Assessment for the Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz

This Local Planning report was prepared by Hydro One Networks Inc. ("HONI"). This report captures the results of the assessment based on information provided by LDCs and HONI.

2 Regional Description and Circuit Q4N Description

Sir Adam Beck GS #1 is an 115kV hydroelectric generating station located on the Niagara Escarpment north of Niagara Falls in Queenston. Geographically, it roughly borders Highway 405 and the Canadian-American border via the Niagara River.

Electrical supply from Sir Adam Beck GS #1 is currently provided through eight (8) OPG generators connected to Hydro One's 115kV solid 'E' bus inside the station. Supply to the local 115kV area is delivered via five (5) Hydro One circuits (Q2AH, Q3N, Q4N, Q11S, Q12S) from 115kV 'E' bus within the power house. The 115 kV 'E' bus serves as a switching station for the Hydro One network as well as a connection facility for OPGI's generators. The generators, transformers and circuits on the 'E' bus are sectionalized via switches.

A single line diagram is shown of the 115 kV system originating from the 115kV Sir Adam Beck GS #1 in Figure 1.

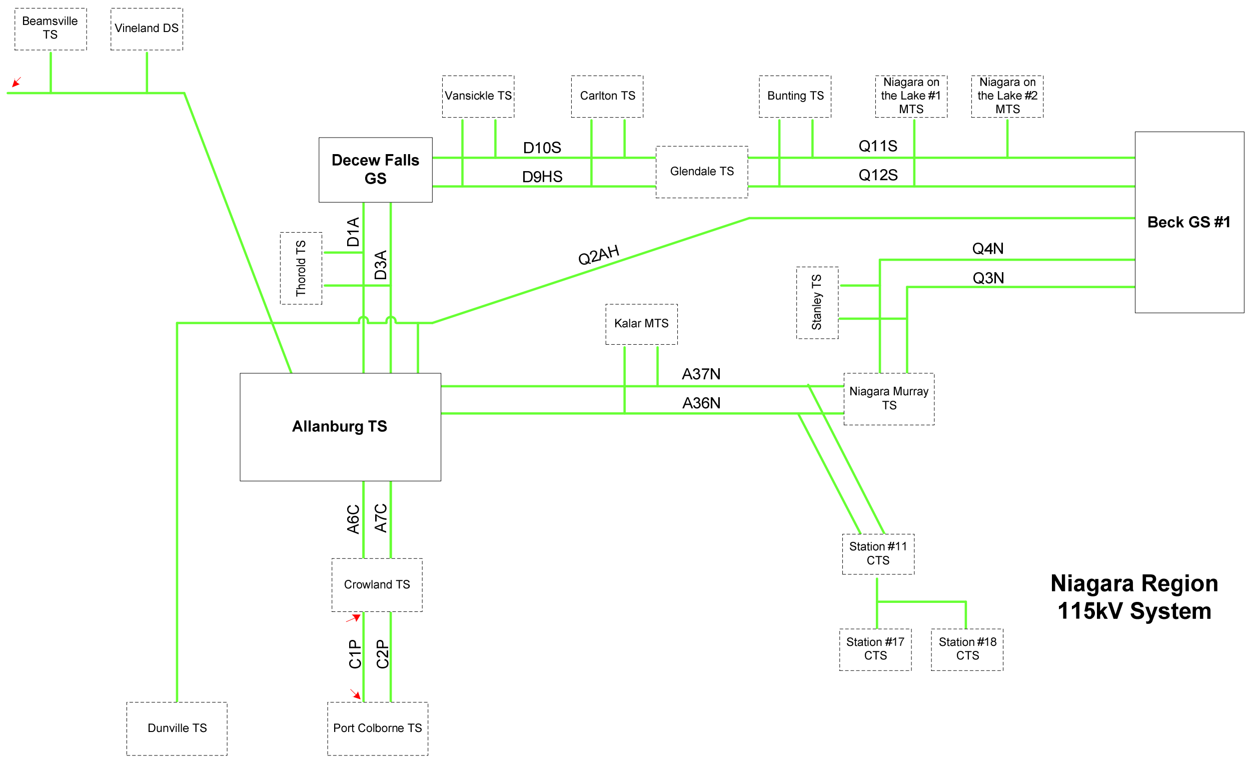

Figure 1: Single Line Diagram – Niagara Region 115kV System

From the NA report for the Niagara Region, a possible thermal limit issue on a section of the circuit Q4N was identified. Q4N is an approximately 9 km long, 115kV radial circuit from Sir Adam Beck GS #1, supplying Stanley TS and Niagara Murray TS.

The section of Q4N identified in the NA comprises of the section from Sir Adam Beck GS #1 to Portal Junction. This section of circuit is shown in Figure 2.

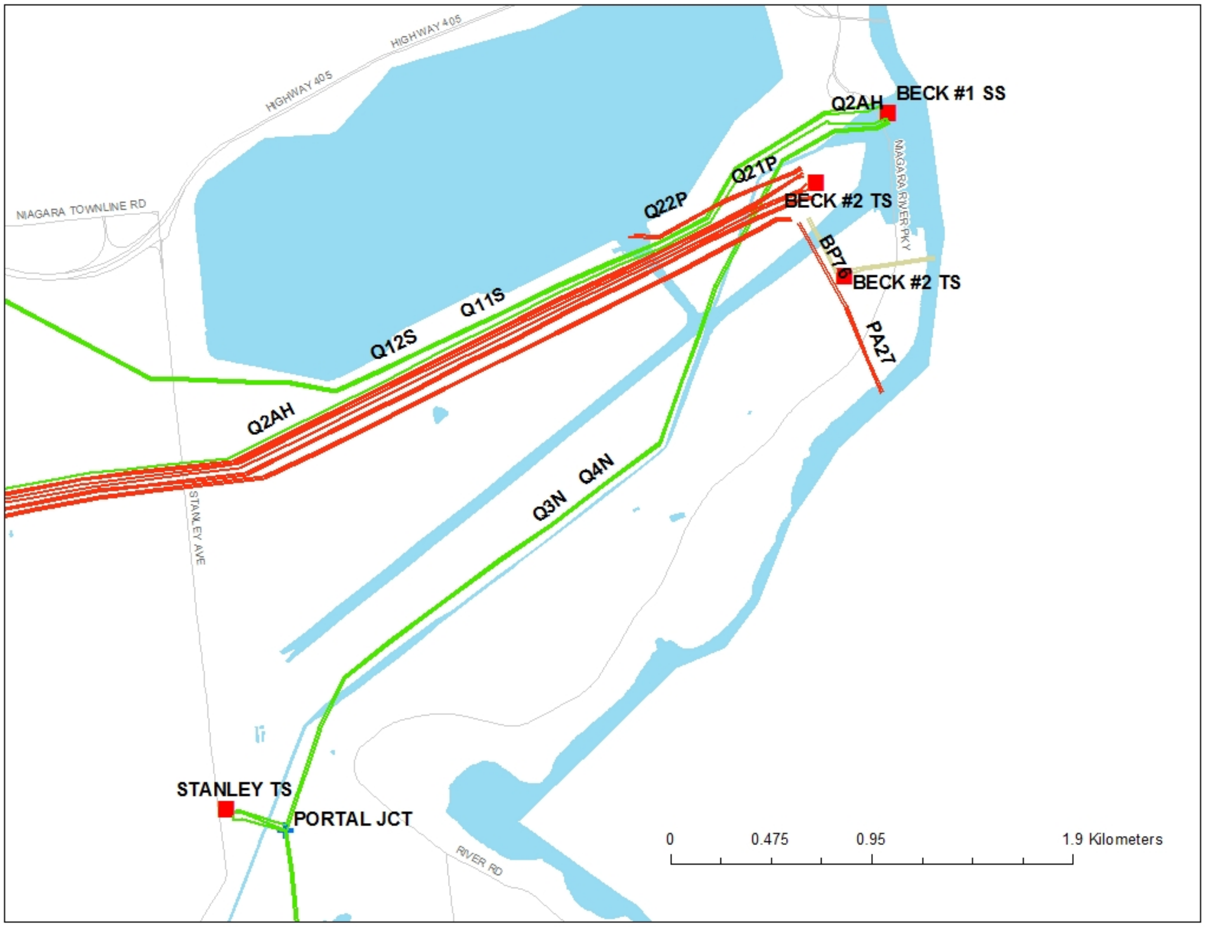

Figure 2: Single Line Diagram – Q4N from Beck #1 SS to Portal Junction

3 Local Niagara Need (Q4N)

In the past decade, OPG has been steadily increasing the power output of their generators with station upgrades.

In the IESO SIA for "Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz" it was identified that the thermal loading on circuit section Q4N from Beck #1 SS to Portal junction exceeds its continuous rating by 109.6% at total generation output of Sir Adam Beck #1 GS. This study was based on 2018 summer peak demand with high generation dispatch in the 115 kV transmission system in the vicinity with the existing 8 generators and 2 future generators (G1 and G2) at full output. This thermal loading is based on an ambient 35ºC temperature condition with 4 km/hr wind speed during daytime.

Reducing the generation output of Sir Adam Beck #1 GS from its maximum capacity of 556 MW to 509 MW reduces the loading on Q4N (Beck #1 SS by Portal Junction) to below its continuous rating.

4 Study Result / Options Considered

The conductor on a 64m section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. is comprised of 605.0 kcmil aluminum, 54/7 ACSR. The continuous rating for this type of conductor at 93^{o}C is 680A. The options considered are outlined below.

4.1 Option 1: Status Quo

Status Quo is not an option because there is a risk that for maximum generation dispatch in extreme weather conditions. Under these conditions generation would have to be curtailed to meet line thermal rating requirements and thus causing financial losses to customer.

4.2 Option 2: Uprate Conductor Section

Hydro One has plans already in place to replace the existing section of conductor with a 910A continuous rated conductor at 93^{o}C as part of their Beck #1 SS Refurbishment project. This will enable this section of circuit to meet all pre and post contingency thermal limits during max generation and under extreme weather conditions.

5 Recommendations

It is recommended that Hydro One continues with their sustainment plans (Option 2) on replacing the section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. with a larger ampacity conductor (increase of 680A to 910A).

The expected in-service date for this conduction section upgrade is December 2019.

6 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

iii) Needs Assessment Report Niagara Region

Appendix A: Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One, NPEI - Embedded	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One & NPEI, Grimsby Power, NPEI - Embedded	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro & Hydro One, CNPI - Embedded	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Hydro One	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One & NPEI	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power, NPEI Embedded	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland DS	Net Load Forecast	17.4	17.0	17.0										
Hydro One, NPEI - Embedded	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Network Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345.5420
Ajay.Garg@HydroOne.com

North/East of Sudbury
Regional Infrastructure Plan ("RIP")

April 13, 2017

Northern Ontario Wires Inc.
Hearst Power Ltd.
North Bay Hydro Distribution Ltd.
Hydro One Networks Inc. (Distribution)

North/East of Sudbury Region is the area roughly bordered by Moosonee on the North, Hearst on the North-West, Ferris South and Kirkland Lake on the East.

The Local Planning ("LP") report for the North/East of Sudbury Region was completed on August 8, 2016 (see attached), and identified the following needs in the region:

- Timmins TS/Kirkland Lake TS – Voltage Regulation Issues:

In the LP report, the study team acknowledged that the Timmins TS 115kV bus may experience voltages below ORTAC requirements following a contingency to both Porcupine TS K1K4 and K1K2 breakers. Operating measures are established to control the voltage decline post contingency, and the study team concluded no action is currently required. Hydro One will continue to monitor Timmins area load growth to ensure operating measures outlined in the LP report continue to be effective for voltage regulations.

The LP also report concluded that corrective actions to control voltage violations on the system may be required for any new loads in the Kirkland Lake or Dymond area.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the RIP for the North/East of Sudbury Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2021) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks Inc.

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

LOCAL PLANNING REPORT

Timmins / Kirkland Lake Voltage Regulation
Region: North & East of Sudbury

Revision: FINAL
Date: August 8, 2016

Prepared by: Hydro One Networks Inc (Transmission & Distribution)

Study Team

Organization
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)

DISCLAIMER

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the North & East of Sudbury Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	North & East of Sudbury (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	May 9, 2016	**END DATE**	November 30, 2016

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only option and recommend a preferred solution that will address the local needs identified in the Needs Assessment (NA) report for the North & East of Sudbury Region dated April 15, 2016. The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

Based on Section 7 of the NA report, the study team recommended that no further coordinated regional planning is required to address the needs in the North & East of Sudbury region. These needs are local in nature and will be addressed by wires options through local planning led by Hydro One with participation of the impacted LDC.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

The Timmins and Kirkland Lake area voltage regulation are local needs addressed in this report.

3. OPTIONS CONSIDERED

Hydro One (Transmitter) and Hydro One Distribution (LDC) have considered addressing the Timmins TS voltage regulation need with the following options;
Alternative 0 – Status Quo.
Alternative 1 - Implement a Load Rejection Scheme on T61S and P7G

Hydro One (Transmitter) and Hydro One Distribution (LDC) have agreed that Alternative 0 – Status Quo is the only option to be considered for Kirkland Lake TS voltage regulation need.

See Section 3 for further detail.

4. PREFERRED SOLUTION

The preferred solution at this time for both the Timmins TS and Kirkland Lake TS voltage regulation needs are Alternative 0 – Status Quo. See Section 4 for details.

5. NEXT STEPS

The next steps are summarized in section 5

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1 Introduction

The Needs Assessment (NA) for the North & East of Sudbury ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. Prior to the new regional planning process coming into effect, planning activities were already underway in the Region to address some specific station capacity needs. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the North & East of Sudbury Region over the next ten years (2016-2026) and recommended whether they should be further assessed through the transmitter-led Local Planning (LP) process or the IESO-led Scoping Assessment (SA) process.

1.1 North & East of Sudbury Region Description and Connection Configuration

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. A map of the region is shown below in Figure 1.

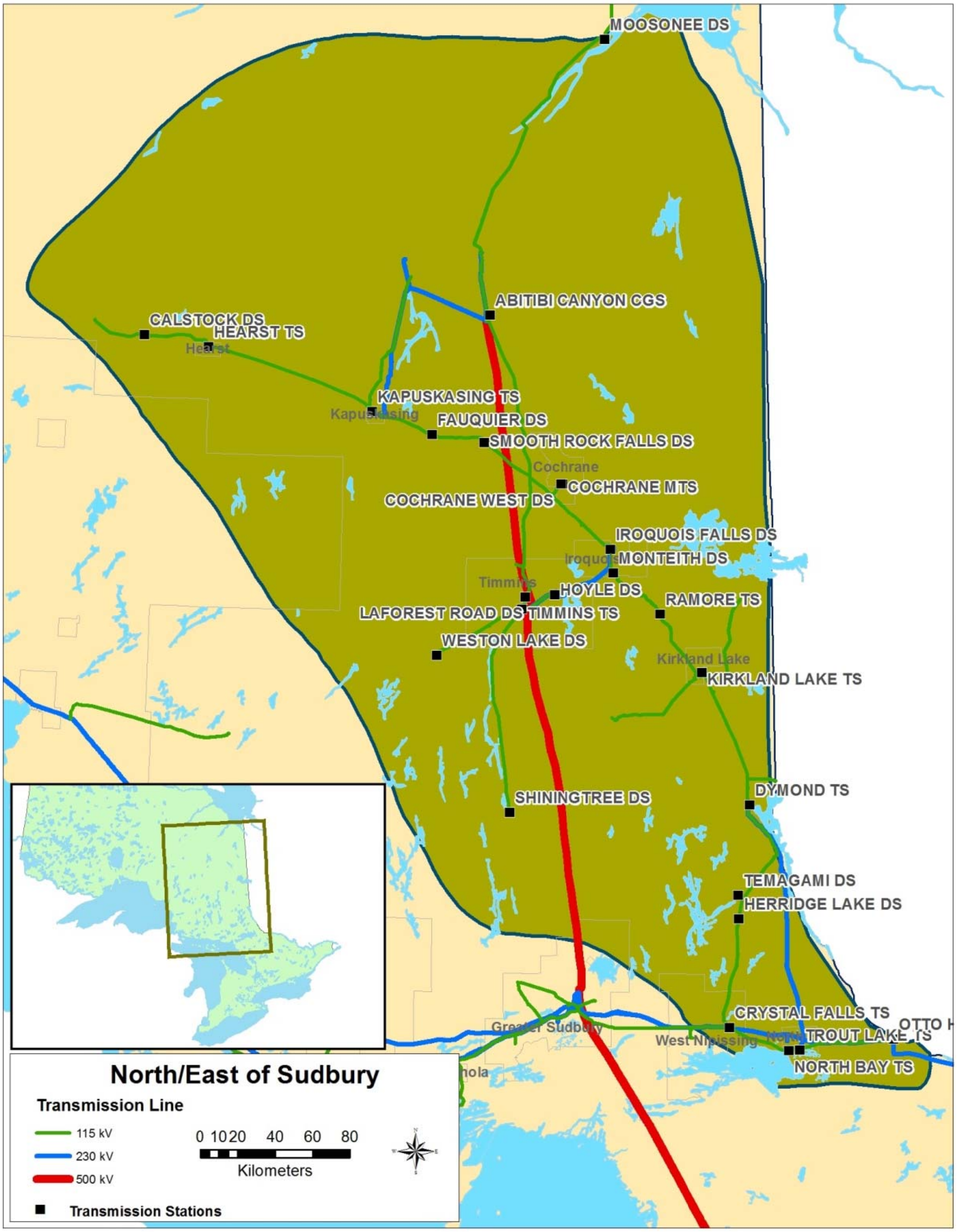

Figure 1: North & East of Sudbury Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Pinard TS to Hanmer TS. This region has the following four local distribution companies (LDC):

Hydro One Networks (distribution)
Northern Ontario Wires Inc
Hearst Power Ltd
North Bay Hydro Distribution Ltd.

Table 1: Transmission Lines and Stations in North & East of Sudbury Region

115kV circuits	230kV circuits	500kV circuits	Hydro One Transformer Stations
L5H, L1S D2L, D3K A8K, A9K K2, K4 A4H, A5H D2H, D3H P7G, H9K P13T, P15T T61S, F1E L8L, T7M T8M, H6T H7T, D6T	H23S, H24S W71D, P91G D23G, K38S R21D, L20D L21S, H22D	P502X, D501P	Ansonville TS * Crystal Falls TS Dymond TS * Hearst TS Hunta SS Kapuskasing TS Kirkland Lake TS Little Long SS Moosonee SS North Bay TS Otter Rapids SS Otto Holden TS * Pinard TS * Porcupine TS * Spruce Falls TS* Timmins TS Trout Lake TS Widdifield SS

*Stations with Autotransformers installed

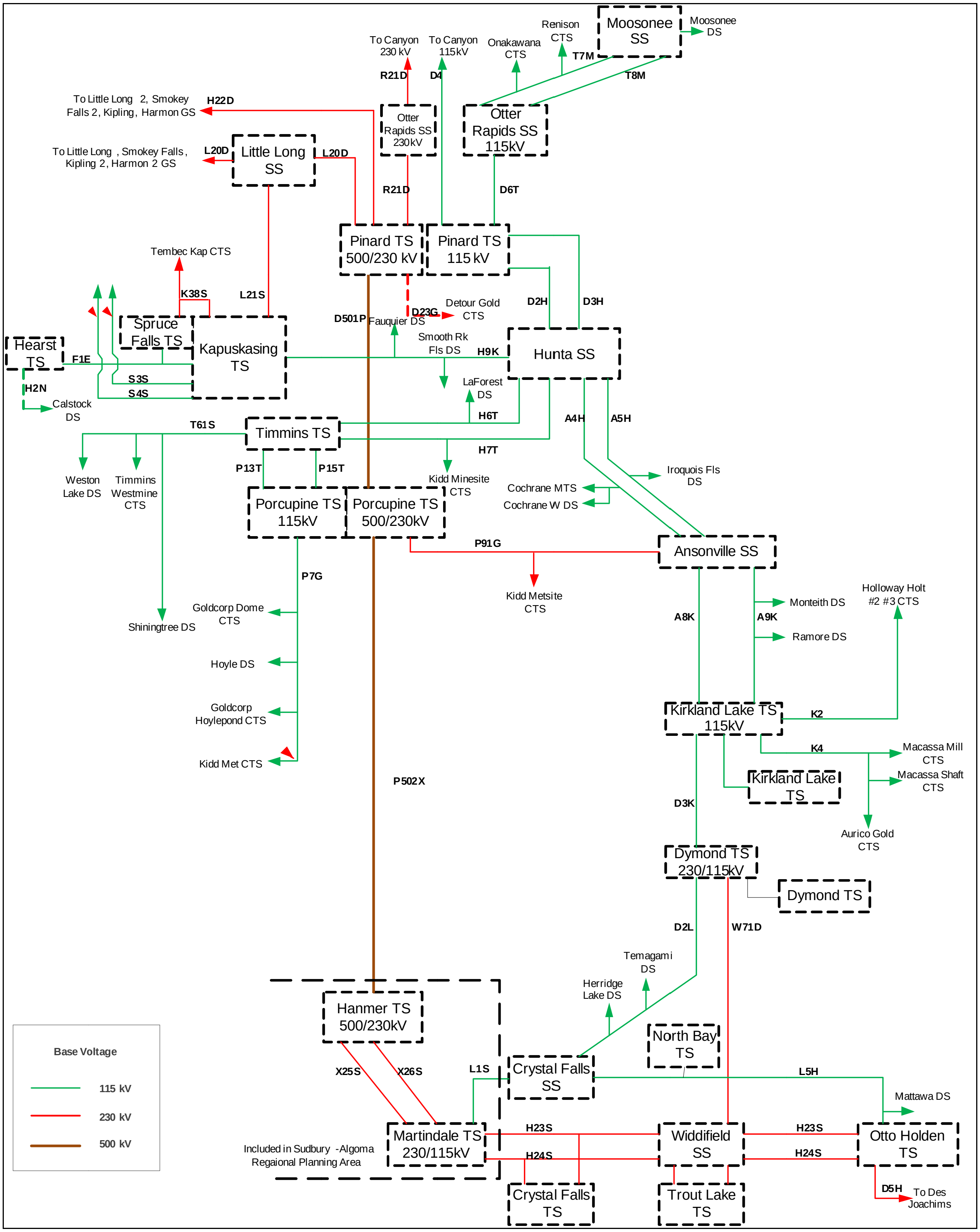

Figure 2: North and East of Sudbury Regional Planning Electrical Diagram

2 Area Needs

2.1 North & East of Sudbury Region Needs

As an outcome of the NA process, the study team identified voltage regulation issues at Timmins TS and Kirkland Lake TS which are addressed in this report. Local planning was recommended, and Hydro One as the transmitter, with the impacted LDC further undertook planning assessments to address the following needs;

- Timmins TS voltage regulation - The loss of Porcupine TS 115kV circuit breakers (K1K4 and K1K2) may result in voltage declines at Timmins TS 115kV bus in excess of 10%. This is considered an n-1-1 contingency and load rejection following the loss of the second element was proposed by IESO to improve post contingency voltage performance. See Figure 3 – Timmins area connection diagram for reference.

- Kirkland Lake TS voltage regulation - The loss of Ansonville T2 and D3K may result in voltage declines at Kirkland Lake TS 115kV bus in excess of 10%. This is considered an n-1-1 contingency and all new loads in the area will be required to participate in a local load rejection scheme to help improve post contingency voltage performance.

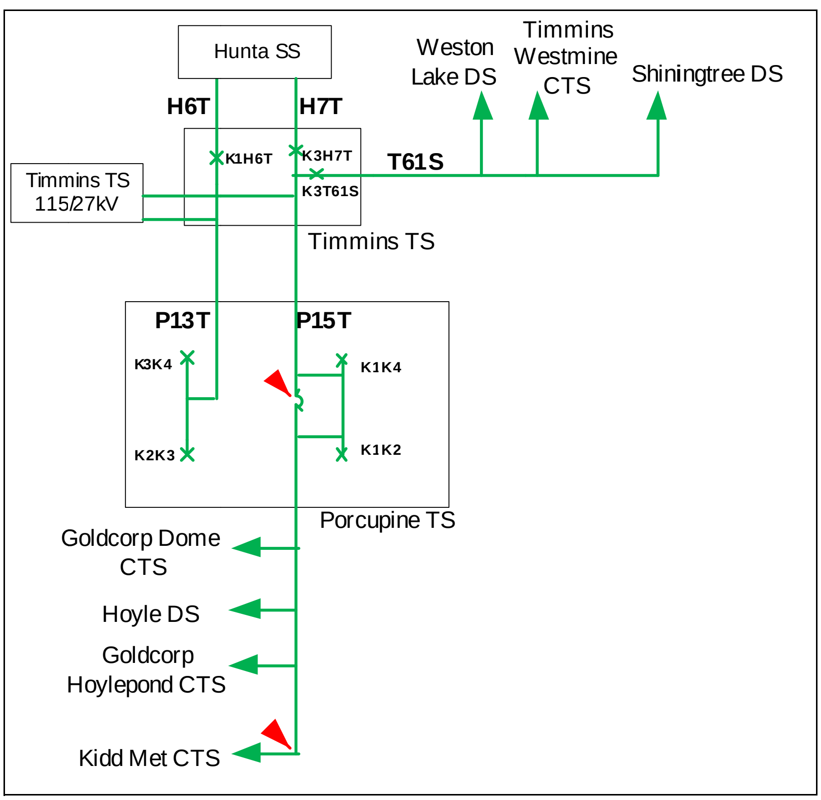

Figure 3: Timmins area connection diagram

3 Alternatives Considered

3.1 Timmins TS Voltage regulation

Alternative 1 – Status Quo.

No further action is required at this time. Hydro One and LDC will monitor the loads and voltages in the area in the upcoming years. Further review of this issue will be undertaken in the next planning cycle or earlier if there is evidence that load cannot be served or system cannot be operated in a safe, secure and reliable manner. Voltage issues can be addressed with operating procedures which are presently in place without any use of load rejection.

Alternative 2 – Implement Load Rejection on T61S, P7G, P15T to control Timmins TS voltages

This option will require expansion of the Northeast LR/GR scheme to include tripping of the Hydro One 115kV T61S, P7G, and P15T circuits upon contingency of both Porcupine TS K1K4 and K1K2 circuit breakers. This will allow for automatic load rejection of approximately 40MW of load.

Table 2: Budgetary Cost for Alternatives

Options Considered	Cost
Alternative 1 – Hydro One to assess voltage performance with no immediate investment.	--
Alternative 2 – Expand Northeast Special Protection Scheme (SPS) to include P15T, P7G, T61S circuits	$2M

3.2 Kirkland Lake TS Voltage regulation

Alternative 1 – Status Quo. See details in section 4 below.

4 Preferred Solution and Reasoning

4.1 Timmins TS Voltage regulation

Hydro One Networks and Hydro One Distribution have reviewed all alternatives and the preferred solution at this time is, Alternative 1 – Status Quo.

The study team acknowledges that Timmins TS 115kV bus may experience voltages below ORTAC requirements following a contingency to both Porcupine TS K1K4 and K1K2 breakers. The possibility of this scenario is remote and there are established operating measures in place should the first Porcupine TS breaker (either K1K4 or K1K2) be placed out of service. The following control measures are taken which help alleviate the voltage decline post contingency.

- Open Timmins TS LV breaker to offload Timmins TS from P15T
- Transfer P7G load to P91G by closing breaker B5L2 at Kidd Creek Metsite and open Porcupine TS switch 30-P7G
- Place one Abitibi Canyon 115kV unit on condenser mode.

Hydro One Networks and Hydro One Distribution have agreed that these operating measures are a preferred alternative to load rejection. In addition, implementing the load rejection scheme will expose the customers in the area to unnecessary interruption due to misoperation of the load rejection scheme.

Hydro One will continue to monitor Timmins area load growth from both LDCs and industrial customers to ensure load growth (if any) does not make voltage situation worse whereby the above operating measures are no longer effective. The next planning cycle will take place within five years and an investment can be triggered at any time should there be a situation where load cannot be served or system cannot be operated safely and reliably.

4.2 Kirkland Lake TS Voltage Regulation

Hydro One Networks and Hydro One Distribution agree that new loads in the Kirkland Lake or Dymond area may be subject to participate in an under voltage load rejection scheme as part to help control voltages in the area post contingency. Presently there is no load growth in the area over the study period. Investments are not required at this time for existing LDC loads and Hydro One will monitor load growth in the area and take corrective action as required or when instructed to do so by the IESO as proponent connection requirements. These will be identified during the load connection process after the connection applications and will be implemented by Hydro One.

5 Next Steps

A summary of the next steps, actions/solutions and timelines required to address the local needs are as follows:

Table 3: Solutions and Timeframe

Need	**Action / Recommended Solution**	**Lead Responsibility**	**Timeframe**
Timmins TS Voltage Regulation	• No Immediate action required • Hydro One and LDC to monitor area load growth	Hydro One Networks	Five years
Kirkland Lake TS Voltage Regulation	• No Immediate action required • Connection requirements for new transmission or distribution connections to be implemented as identified during system studies.	Hydro One Networks	N/A

6 References

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

[3] North & East of Sudbury Needs Assessment Report

Appendix A: Load Forecast for North & East of Sudbury Stations

Transformer Station Name	Customer Data (MW)	Historical Term Forecast (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Kapuskasing TS	Gross Peak Load				13.5	13.6	13.6	13.7	13.8	13.8	13.9	13.9	14.0	14.0	14.0
	Net Load Forecast	26.1	16.1	13.5	13.4	13.3	13.2	13.2	13.1	13.1	13.1	13.0	13.0	13.0	13.0
Trout Lake TS	Gross Peak Load				121.9	122.2	122.7	123.3	123.9	125.3	126.7	127.1	128.4	129.8	131.2
	Net Load Forecast	147.5	124.1	119.4	120.6	120.0	119.1	118.5	118.1	118.7	119.2	119.1	119.7	120.5	121.1
Dymond TS	Gross Peak Load				32.7	32.9	33.1	33.6	34.0	34.2	34.4	34.6	34.8	35.0	35.2
	Net Load Forecast	37.7	34.6	32.4	32.4	32.3	32.2	32.2	32.4	32.4	32.4	32.4	32.4	32.5	32.5
Kirkland Lake TS	Gross Peak Load				32.2	32.3	32.6	32.9	33.3	33.5	33.7	33.8	34.0	34.1	34.3
	Net Load Forecast	43.8	35.7	31.9	31.9	31.7	31.6	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.6
Timmins TS	Gross Peak Load				53.4	53.7	54.2	54.9	55.6	56.0	56.4	56.7	57.0	57.4	57.7
	Net Load Forecast	51.0	51.1	52.9	52.8	52.7	52.6	52.7	53.0	53.0	53.0	53.1	53.2	53.2	53.3
Hearst TS	Gross Peak Load				27.5	27.6	28.8	29.1	29.3	29.5	29.7	29.9	30.0	30.2	30.4
	Net Load Forecast	27.8	27.3	27.2	27.2	27.1	28.0	27.9	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Herridge Lake DS	Gross Peak Load				3.0	3.1	3.1	3.2	3.2	3.3	3.3	3.4	3.4	3.5	3.5
	Net Load Forecast	3.5	3.8	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2
Temagami DS	Gross Peak Load				2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6
	Net Load Forecast	2.5	2.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
LaForest Rd TS	Gross Peak Load				10.4	10.4	10.5	10.7	10.8	10.9	10.9	11.0	11.1	11.1	11.2
	Net Load Forecast	12.8	9.7	10.3	10.3	10.2	10.2	10.2	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Hoyle TS	Gross Peak Load				8.9	8.9	9.0	9.2	9.3	9.4	9.5	9.5	9.6	9.7	9.7
	Net Load Forecast	9.3	10.4	8.8	8.8	8.8	8.8	8.8	8.9	8.9	8.9	8.9	8.9	9.0	9.0
Monteith DS	Gross Peak Load				2.8	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.0
	Net Load Forecast	3.1	2.9	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Ramore TS	Gross Peak Load				9.1	9.2	9.3	9.5	9.7	9.8	9.9	10.1	10.2	10.3	10.4
	Net Load Forecast	8.2	9.1	8.9	9.0	9.0	9.1	9.1	9.2	9.3	9.4	9.4	9.5	9.6	9.6
Cochrane West DS	Gross Peak Load				3.8	3.8	3.8	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.1
	Net Load Forecast	4.1	4.1	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Smooth Rock Falls DS	Gross Peak Load				2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4
	Net Load Forecast	2.4	2.4	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Fauquier DS	Gross Peak Load				2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4
	Net Load Forecast	2.3	2.3	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2
Moosonee DS	Gross Peak Load				14.2	14.3	14.4	14.6	14.8	14.9	15.0	15.0	15.1	15.2	15.3
	Net Load Forecast	18.0	13.5	14.1	14.1	14.0	14.0	14.0	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Calstock DS	Gross Peak Load				5.0	5.0	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.5
	Net Load Forecast	5.1	4.9	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1
Mattawa DS	Gross Peak Load				5.5	5.5	5.6	5.7	5.7	5.8	5.8	5.8	5.9	5.9	5.9
	Net Load Forecast				5.4	5.4	5.4	5.4	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Iroquois Falls DS	Gross Peak Load				10.8	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.2	11.3	11.3
	Net Load Forecast	5.1	4.9	4.9	10.7	10.7	10.6	10.6	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Crystal Falls TS	Gross Peak Load				9.9	10.0	10.0	10.2	10.3	10.4	10.4	10.5	10.5	10.6	10.6
	Net Load Forecast	18.7	11.1	9.8	9.8	9.8	9.7	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Cochrane MTS	Gross Peak Load				11.3	11.4	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
	Net Load Forecast	10.3	10.9	11.1	11.1	11.2	11.2	11.1	11.0	11.0	10.9	10.8	10.8	10.7	10.7
North Bay	Gross Peak Load				39.0	39.0	39.0	39.0	39.0	39.4	39.8	40.2	40.6	41.0	41.4
	Net Load Forecast	29.0	39.0	25.0	38.6	38.3	37.9	37.5	37.2	37.3	37.4	37.7	37.8	38.0	38.2

Load Forecast for North & East of Sudbury Stations (Continued)

Transformer Station Name	Customer Data (MW)	Historical Term Forecast (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Weston Lake DS	Gross Peak Load				4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4
	Net Load Forecast	4.1	4.3	4.1	4.0	4.0	4.0	4.1	4.1	4.1	4.1	4.2	4.2	4.2	4.2
Shiningtree DS	Gross Peak Load				4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4
	Net Load Forecast	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.2	4.2	4.2	4.2

Appendix B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Planning
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: North and East of Sudbury

Date: April 15, 2016

Prepared by: North and East of Sudbury Region Working Group

North & East of Sudbury Working Group	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Kirpal Bahra Qasim Raza
Independent Electricity System Operator	Chris Reali Philip Woo
Hydro One Networks Inc. (Distribution)	Richard Shannon Daniel Boutros
Northern Ontario Wires Inc	Dan Boucher
Hearst Power Ltd	D Sampson J Richard
North Bay Hydro Distribution Ltd	Matt Payne

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the North & East of Sudbury region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by Working Group participants.

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NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	North & East of Sudbury (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 15, 2015	**END DATE**	April 15, 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the North & East of Sudbury Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the North & East of Sudbury Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The North & East of Sudbury Region belongs to Group 3, triggered on October 15, 2015 and completed on April 17, 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2026. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Working Group participants included representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2016 to 2026). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required.

6. RESULTS - TRANSMISSION NEEDS

A. 500/230kV Autotransfomers
The 500/230kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/230kV unit.

B. 500/115kV Autotransfomers
The 500/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/115kV unit

C. 230/115 kV Autotransformers
The 230/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 230/115kV unit

D. Transmission Lines & Ratings
The 500kV, 230kV transmission lines are adequate over the study period.

Sections of the 115kV H9K circuit may experience thermal overloads during high generation scenarios. This is a bulk system issue and will be addressed jointly with the IESO outside of regional planning.

E. 230 kV and 115 kV Connection Facilities
The 230kV and 115kV connection facilities in this region are adequate over the study period.

F. Outage Condition resulting in P15T,P7G and T61S radially connected to Timmins TS
The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus

G. Ansonville T2 or D3K Outages
With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at the Kirkland Lake TS 115kV bus.

System Reliability, Operation and Restoration Review

Circuit reliability in the region is acceptable, and Hydro One will continue to monitor performance of supply stations and circuits to ensure customer delivery performance criteria are met.

Restoration requirements for the loss of one element can be met by Hydro One.
Restoration requirements for the loss of up to two elements can be met by Hydro One.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following work is part of Hydro One approved sustainment business plan

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

7. RESULTS – NEEDS ASSESSMENT REPORT

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and following needs identified be further assessed as part of Local Planning:

Timmins TS / Kirkland Lake TS – Voltage Regulation Issues

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LIST OF FIGURES

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the North & East of Sudbury Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the North & East of Sudbury Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. If localized wires only solutions do not require further coordinated regional planning, the SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by Hydro One Inc ("Hydro One") on behalf of the North & East of Sudbury Region NA Working Group (Table 1). The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Working Group Participants for North & East of Sudbury Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Northern Ontario Wires Inc
4.	Hydro One Networks Inc. (Distribution)
5.	Hearst Power Ltd
6.	North Bay Hydro Inc.

2 REGIONAL ISSUE / TRIGGER

The NA for the North & East of Sudbury Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The North & East of Sudbury Region belongs to Group 3.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the North & East of Sudbury Region over an assessment period of 2016 to 2026. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

North & East of Sudbury Region Description and Connection Configuration

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. A map of the region is shown below in Figure 1.

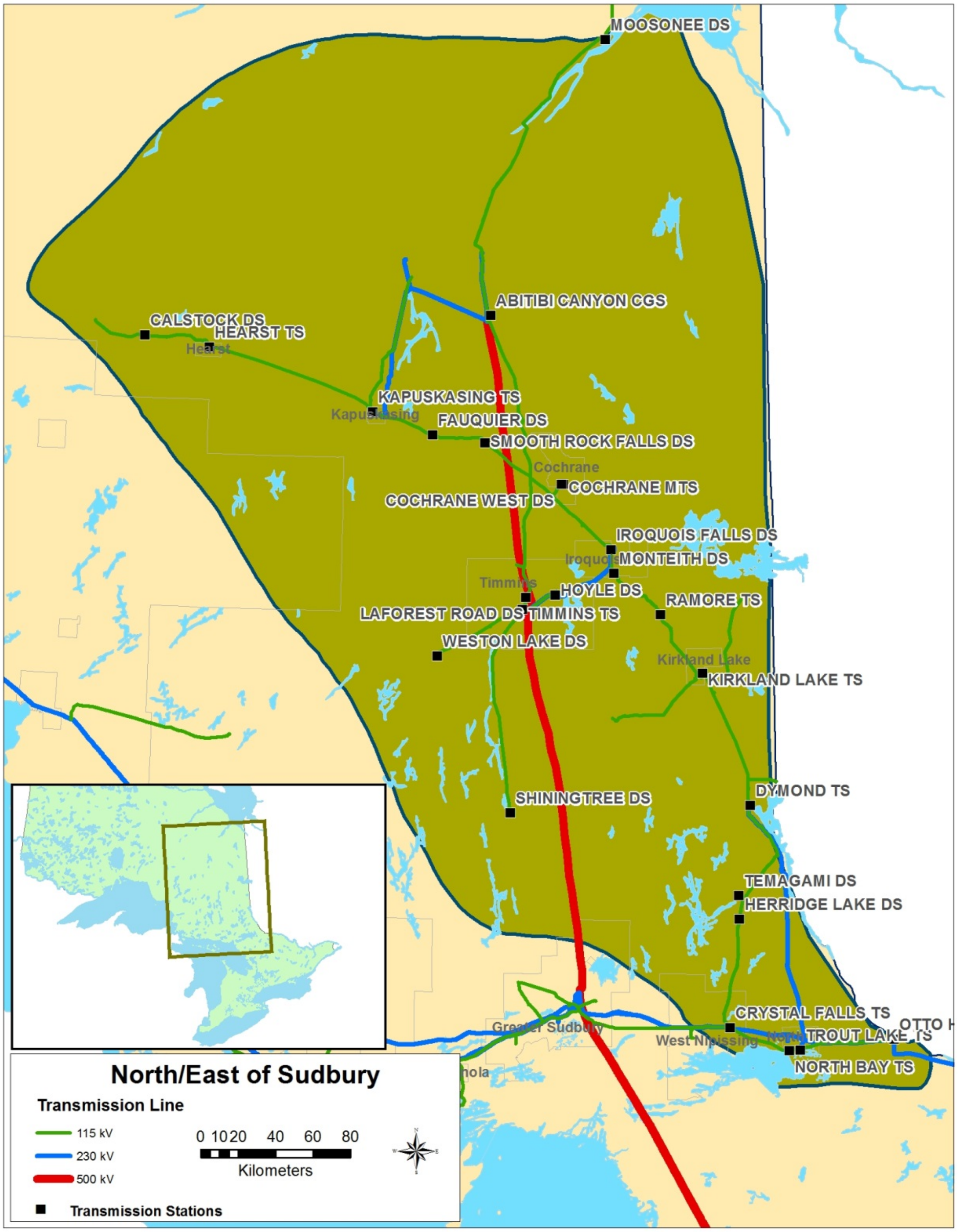

Figure 1: North & East of Sudbury Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Pinard TS to Hanmer TS.

This region has the following four local distribution companies (LDC):

- Hydro One Networks (distribution)
- Northern Ontario Wires Inc
- Hearst Power Ltd
- North Bay Hydro Distribution Ltd.

115kV circuits	230kV circuits	500kV circuits	Hydro One Transformer Stations
L5H, L1S D2L, D3K A8K, A9K K2, K4 A4H, A5H D2H, D3H P7G, H9K P13T, P15T T61S, F1E L8L, T7M T8M, H6T H7T, D6T	H23S, H24S W71D, P91G D23G, K38S R21D, L20D L21S, H22D	P502X, D501P	Ansonville TS * Crystal Falls TS Dymond TS * Hearst TS Hunta SS Kapuskasing TS Kirkland Lake TS Little Long SS Moosonee SS North Bay TS Otter Rapids SS Otto Holden TS * Pinard TS * Porcupine TS * Spruce Falls TS * Timmins TS Trout Lake TS Widdifield SS

***Stations with Autotransformers installed**

Table 2: Transmission Lines and Stations in North & East of Sudbury Region

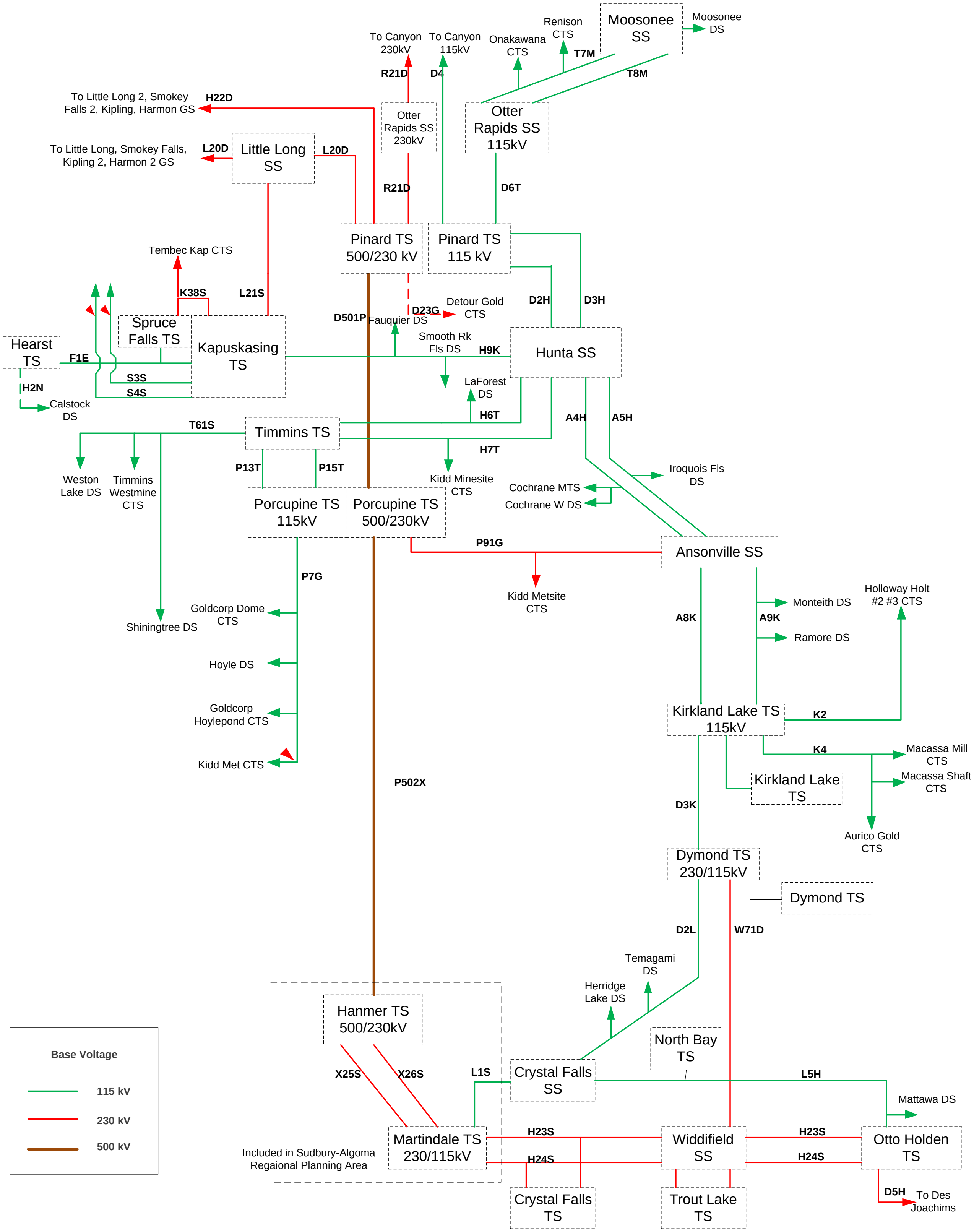

Figure 2 – North and East of Sudbury Regional Planning Electrical Diagram

4 Inputs and Data

In order to conduct this Needs Assessment, Working Group participants provided the following information and data to Hydro One:

- IESO provided:
  - i. Historical Ontario and regional coincident load station peaks, as well as individual station peaks.
  - ii. List of existing reliability and operational issues
  - iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2013-2015) net load and gross load forecast (2016-2026) Note: 2026 gross load values were extrapolated from 2025 if required.
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

Load Forecast
As per the data provided by the Working Group, the gross load in region is expected to grow at an average rate of approximately 0.7% annually from 2016-2026.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to increase at an average rate of approximately 0.04% annually from 2016-2026.
Note: Extreme weather scenario factor at 1.057 assessed over the study term.

5 Needs Assessment Methodology

The following methodology and assumptions are made in this Needs Assessment:

1. The Region is winter peaking so this assessment is based on winter peak loads.
2. Forecast loads are provided by the Region's LDCs
3. Load data was provided by industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
4. Accounting for (2), (3) above, the gross load forecast and net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG are analyzed to determine if needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report. A gross and net region-coincident peak load forecast was used to perform the analysis.

5. Review impact of any on-going and/or planned development projects in the Region during the study period.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the winter 10-Day Limited Time Rating (LTR). Summer LTR ratings also were reviewed against the station load forecasts over the study period.
8. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
9. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. Note: This criterion was put in place after the 500 kV Northeast system was built and as such, the system was not originally designed to respect this criteria for the loss of the 500 kV circuits P502X or D501P. Currently the loss of either these circuits can result in the loss of more than 150 MW.
    - With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With up to two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 RESULTS

6.1 500/230kV Autotransfomers
The 500/230 kV transformers supplying the region are adequate for loss of single 500/230 kV unit.

6.2 500/115kV Autotransfomers
The 500/115kV transformers supplying the region are adequate for loss of single unit.

6.3 230/115kV Autotransfomers
The 230/115kV transformers supplying the region are adequate for loss of single unit.

6.4 Transmission Lines and Ratings
The 500kV and 230 kV circuits supplying the region are adequate over the study period for the loss of a single 500kV or 230 kV circuit in the Region.
As per section 7.2 below – the 115kV H9K circuit may experience thermal overloads and will be addressed as a bulk system issue outside of regional planning.

6.5 230 kV and 115 kV Connection Facilities
A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station winter peak load forecast provided by the Working Group. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario

7 SYSTEM RELIABILITY, OPERATION AND RESTORATION

7.1 Performance
The areas of Timmins, Dymond and Abitibi Canyon have experienced severe weather patterns over the last 5 years causing periodic increases of both momentary and sustained outages which have been highlighted by the IESO. The region (including the three mentioned above) does not have circuit performance outliers which would fall below customer delivery point performance standards set forth by the Ontario Energy Board.

Hydro One continually monitors performance of supply stations, and high voltage circuits and will make the necessary steps to address the problem should this issue persist.

7.2 Restoration
Depending on system conditions, the loss of P502X may result in the greatest amount of load lost through North East LR/GR special protection schemes. Based on the load levels in the study period of this assessment, load can be restored within the 30 minute, 4 hour and 8 hour time frames as required by IESO ORTAC Section 7.0. The maximum load which may be interrupted by configuration or load rejection due to the loss of two elements is up to 450MW which is below the ORTAC requirement of 600MW. (loss of P502X with D3K out of service, or vice versa)

7.3 Thermal overloading on H9K section

Under high generation scenarios, IESO has identified pre and post contingency overloads on the 115 kV circuit H9K between *Tembec SRF x H9K 127A* junction.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.4 Congestion on D3K, A8K, A9K, H6T and H7T

Under high generation scenarios, IESO has identified there may be congestion on D3K, A8K, A9K, H6T and H7T circuits.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.5 Kapuskasing and Calstock Area Generation

Non-utility Generator ("NUG") contracts are reaching end of term for the Kapuskasing and Calstock Generating Stations. The NUG Framework Assessment Report [1] indicated that local reliability and congestion issues may require further study as this pertains to contracted generation facilities. This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.6 Outage Condition Resulting in P15/P7G/T61S radially connected to Timmins

The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus.
This scenario will be addressed in the next stage of regional planning.

7.7 Ansonville T2 or D3K outages

With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at Kirkland Lake TS. This scenario will be addressed in the next stage of regional planning.

8 AGING INFRASTRUCTURE AND REPLACEMENT OF MAJOR EQUIPMENT

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. during the study period. At this time the major committed system investments are;

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

9 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, it is further recommended that voltage regulation issues at Timmins TS and Kirkland Lake TS be best addressed by wires options solution thru local planning led by Hydro One:

10 NEXT STEPS

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and the two voltage regulation needs identified in Section 7 be further assessed as part of Local Planning to be entitled:

<u>Timmins TS / Kirkland Lake TS – Voltage Regulation Issues</u>

11 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: March 2014 – August 2015
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

12 Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Network Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345.5420
Ajay.Garg@HydroOne.com

Renfrew Region

Regional Infrastructure Plan ("RIP")

July 22nd, 2016

Independent Electricity System Operator
Renfrew Hydro Inc.
Ottawa River Power Corporation
Hydro One Networks Inc. (Distribution)

The Renfrew Region consists of Renfrew County and it is roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast.

The Needs Assessment ("NA") report for the Renfrew region was completed in March, 2016 (see attached). The report concluded that no regional planning needs were identified for the region at this time although circuit X1P is nearing its capacity and will be monitored on a regular basis over the next three to five years.

There are no other major development projects planned for the Renfrew Region over the near and mid-term.

Consistent with a process established by an industry working group[1] created by the OEB, the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no regional planning was required, this letter and the attached NA report will be deemed to form the ("RIP") for the Renfrew Region.

The next regional planning cycle for the region is expected to be undertaken in five years from the start of this planning cycle (2015) or earlier if there is a new need emerging in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: Renfrew

Revision: Final
Date: March 11, 2016

Prepared by: Renfrew Study Team

Transmission

Distribution

Peterborough to Renfrew Region Study Team
Organization
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Renfrew Hydro Inc.
Ottawa River Power Corporation
Hydro One Networks Inc. (Distribution)

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Renfrew Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Renfrew Region (the Region)		
LEAD	Hydro One Networks Inc. (Hydro One)		
START DATE	October 23, 2015	**END DATE**	March 11, 2016

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the Renfrew Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Assessment for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups - Group 1 Regions are being reviewed first. The Renfrew Region belongs to Group 3. The Needs Assessment for this Region was triggered on October 23, 2015 and was completed on March 11, 2016.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years as per the recommendations of the Planning Process Working Group Report to the Board.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year IRRP with strategic direction for the Region.

The assessment included a review of transmission system connection facilities capability, which covers station loading, thermal, and voltage analysis, system reliability, and assets approaching end-of--life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Renfrew Region. The information included: existing information from planning activities already underway, historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-life.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2015 to 2024). The assessment reviewed available information and load forecasts and included single contingency analysis to identify needs.

6. RESULTS

Transmission Capacity Needs

A. Station Capacities

- All stations in the region have sufficient capacity to supply the loads in studied period under normal and single contingency condition.

B. Transmission Circuits Capacities

- All transmission circuits have sufficient capacity under normal and single contingency condition.

System Reliability, Operation and Restoration Needs

There are no transmission system reliability issues and no operating issues identified for one element out of service in this Region.

Based on the gross coincident demand forecast, loss of one element will not result in load interruption for more than 150MW by configuration.

All load within the region can typically be restored within eight hours as per the ORTAC requirement for loads under 150 MW.

In recent years, maintenance activity in the region with respect to vegetation management has been enhanced resulting in an improvement in reliability and/or load restoration.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at three stations will increase station capacities. Further details of these investments can be found in Section 3.2 of this report.

7. RECOMMENDATIONS

Based on the findings of this Needs Assessment, the study team's recommendations are as follows:

- Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

- No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region.

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LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment report provides a description of the analysis to identify needs that may be emerging in the Renfrew Region (the Region) over the next ten years. The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this Needs Assessment report is to: consider the information from planning activities already underway; undertake an assessment of the Renfrew Region to identify near term and/or emerging needs in the area; and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with LDCs or other connecting customer(s) will further undertake planning assessments to develop options and recommend solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (the IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by Hydro One (Lead Transmitter) with input from the Renfrew Region Needs Assessment study team. The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1 Study Team Participants for Renfrew Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Hydro One Networks Inc. (Distribution)

2 TRIGGER OF NEEDS SCREEN

The Needs Assessment for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The Region falls into Group 3. The Needs Assessment for this Region was triggered on October 23, 2015 and was completed on March 4, 2016.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the Renfrew Region over an assessment period of 2015 to 2024. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuits thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

3.1 Renfrew Region Description and Connection Configuration

The Renfrew Region includes all of Renfrew County. Fig.1 shows the map of the Region. The 2014 peak load in this Region was 124 MW.

The electricity supply to the region is mainly through one 230kV circuit X1P and three 115 kV radial circuits: D6, X6 and X2Y (Fig.1). The 115kV circuits are supplied by 230/115 kV autotransformers at Chenaux Transformer Station (TS) from the East and Des Joachims TS from the West. A normally opened 115kV switch at Pembroke TS isolates the East and the West sides of the region.

The Renfrew Region is roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast. The distribution system in this region consists of voltage levels 44 kV, 13.8 kV, and 12.5 kV. The main generation facilities in the Renfrew Region are Chenaux Generation Station (GS) of 143.7 MW (according to Transmission Connection Agreement, applicable thereafter), Mount Chute GS of 170.2 MW and Des Joachims GS of 432.5 MW.

Hydro One Networks Inc. (Distribution) is the main customer in the area. Other Local Distribution Companies (LDC) supplied from electrical facilities in the Renfrew Region includes Ottawa River Power Corporation and Renfrew Hydro Inc, both are embedded into Hydro One's distribution system. Major transmission connected customers in the area include Canadian Nuclear Laboratories and Magellan Aerospace.

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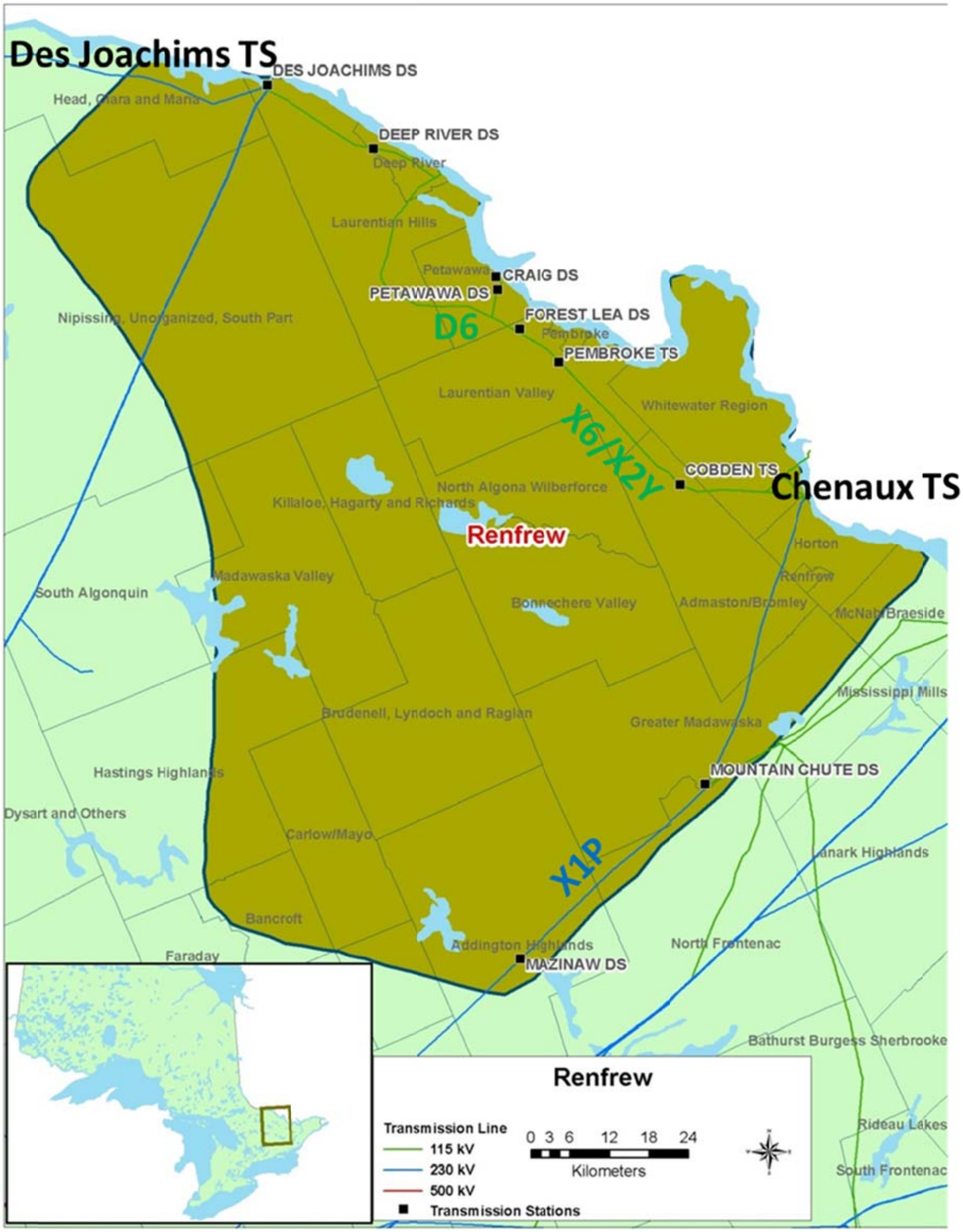

Fig. 1 Renfrew Region Map

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Fig. 2.

- Des Chenaux TS is a major 230kV station in the region. The station has 143.7MW of hydraulic generation connected to the 230kV bus. The station connects to the bulk system via a single 230kV circuit X1P. Two autotransformers step down the voltage to 115kV to supply two radial circuits X6 and X2Y.

- The 115kV circuits X6 and X2Y from Chenaux TS supply four stations: Pembroke TS, Cobden TS, Cobden DS and Magellan Aerospace CTS. The two circuits are coupled via and only via Pembroke 44kV bus tie breaker

- Des Joachim TS is the other major 230kV transformer station in the Region. There are 432.5MW of hydraulic generation units connecting to the 230kV bus. The station interconnects to the Bulk Electric System (BES) via five 230kV circuits which are not in the scope of this regional assessment. Two autotransformers (one operates as standby) step down the voltage to 115kV to supply one radial circuit D6.

- The 115kV circuit D6 from Des Joachim TS 115kV bus supplies six stations: Des Joachims Distribution Station (DS), Deep River DS, Craig DS, Forest Lea DS, Petawawa DS, and Chalk River Customer Transformer Station (CTS).

- All the 115kV circuits X6/X2Y/D6, all the 115kV stations tapped to the 115kV circuits, and all the autotransformers at Des Joachims TS and Chenaux TS are not NERC BES element.

- Bryson GS of Hydro Quebec can be radially connected to Renfrew region via X2Y.

- The 230kV single circuit X1P from Dobbin TS to Chenaux TS connects two stations in Renfrew Region: Mountain Chute GS (with hydraulic generation of 170.2MW) and Mazinaw DS.

- Mountain Chute DS, a 115kV station adjacent to Mountain Chute GS, is supplied by a circuit W3B from outside of the studied region. The DS typically has load less than 1MW.

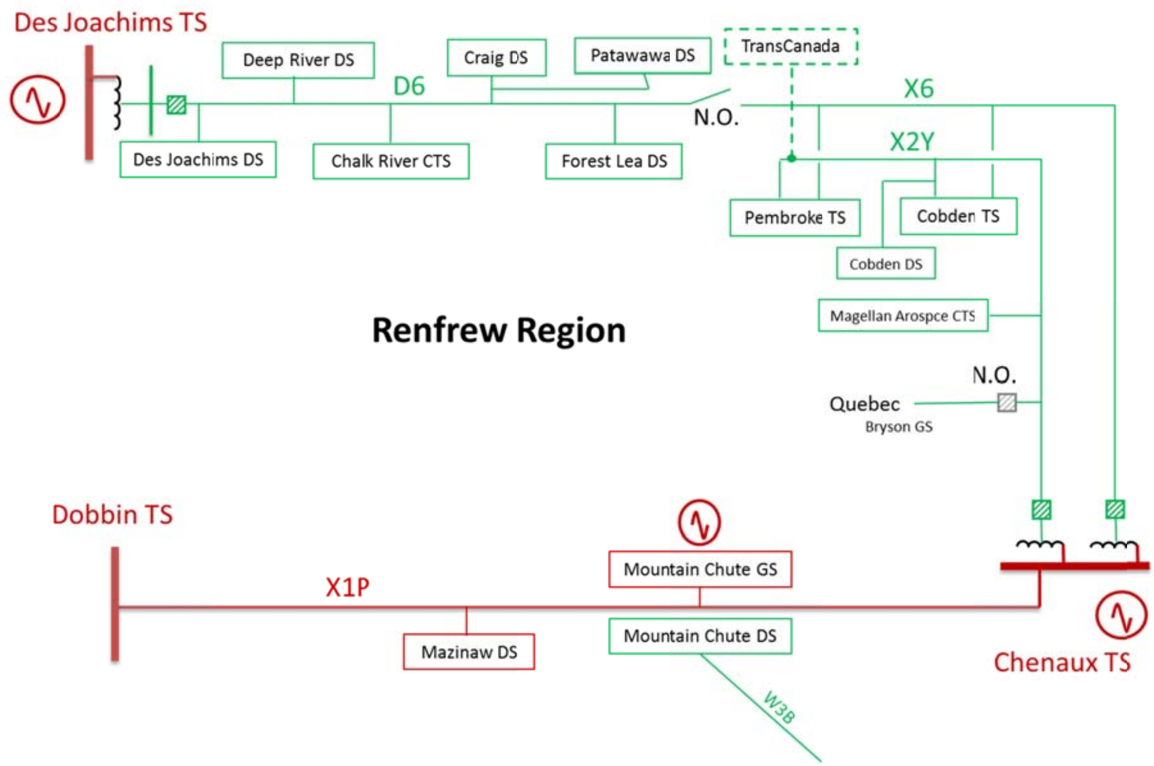

Fig. 2 Single Line Diagram – Renfrew Region

3.2 Planned Work in Renfrew Region

Following work has been planned in Renfrew Region:

- Two step-down transformers at Deep River DS (T1 and T2) will be replaced due to end-of-life for an in service date of end of 2016. This will also result in uprating the transformer capacity from 10MVA to 12.5MVA.
- Mountain Chute DS transformer will be replaced due to end-of-life with an in service date of end of 2016. This will also result in uprating the transformer capacity from 3MVA to 12.5MVA.
- Chenaux TS 230/115kV autotransformers T3 and T4 will be replaced due to end-of-life with an in service date of end of 2018. The existing units are rated 78MVA and 115MVA respectively. The new T3/T4 will both have continuous rating of 125MVA. This is a transmission pool investment and LDCs are not expected to pay.
- A TransCanada pump station is expected to tap to X2Y at Pembroke TS (Fig.2). The peak load of the station is 19.4MW. Two capacitor banks, each rated at 10Mvar, are assumed to be in service with the load. The station is expected to be in service in 2020.

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information to Hydro One:

- IESO provided:
  i. Historical regional coincident peak loads and station non-coincident peak loads between 2012 and 2014
  ii. List of existing reliability and operational issues
  iii. Conservation and Demand Management (CDM) and future Distributed Generation (DG) data
- LDCs provided historical (2012-2014) net loads and gross loads forecasts (2015-2024) for each station.
- The study team could not get response from Chalk River CTS and Magellan Aerospace CTS regarding their load forecasts. It is assumed that the loads at these two stations would not increase over the study period.
- Any relevant planning information, including planned transmission and distribution investments are provided by the transmitter and LDCs.

As per the data provided by the study team, the net load (i.e. after DG and CDM adjustment) in the Renfrew Region is expected to grow at an average rate of approximately 0.6% annually from 2015 to 2024.

5 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

1. The Region typical typically has winter peak. Fig. 3 plots the load profiles at Pembroke TS and Cobden TS from July 2013 to July 2015, which evidences the winter peaking characteristics. Therefore this assessment is based on winter peak load.

2. Loads forecasts are provided by the LDCs, i.e., Hydro One Networks Inc. (Distribution) in this case.

3. Average gross load growth rate at each station is calculated from the LDC's load forecast. The growth rates are then applied to the 2014 coincidental winter peak load to generate each year's coincidental peak load.

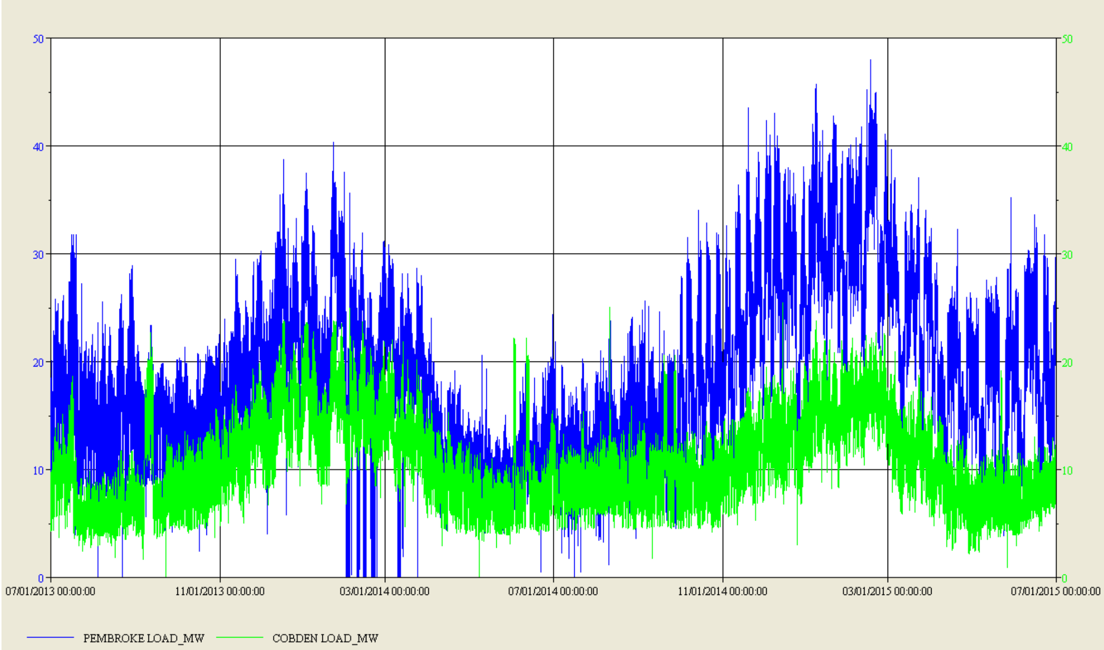

Fig. 3 Pembroke TS and Cobden TS Winter Peak Load Profiles

4. The 2014/15 winter was already extremely cold; therefore no extreme weather adjustment was used.

5. The gross demand forecast is used to develop a worst case scenario to identify needs. Both the gross demand forecast and the net demand forecast (which includes forecasted CDM and DG contributions) were used to determine the timing of the needs.

6. Review impact of any on-going and planned development projects in the Region during the study period. This includes:

    - A new 19.4MW load is expected to connect to circuit X2Y at Pembroke in 2020. This Needs Assessment assumes that the load is in service.

7. Review and assess impact of any major elements planned to be replaced at the end of their useful life such as transformers, cables, and stations.

8. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks and 95% lagging power factor for stations with low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Region is determined by the 10-Day Limited Time Rating (LTR).

9. To identify emerging needs in the Region and determine whether further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment is primarily based on the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range. Projected coincidental peak loads are used in such assessment.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC). Des Joachims and Chenaux 115kV bus voltages are maintained between 122kV and 127kV according to established operation practice.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - The system is capable of meeting the load restoration time limits as per ORTAC criteria.

11. Full load transfers for restoration purposes are not mandatory requirement. Restorations of load between Chenaux TS and Des Joachims TS via D6-X6 load transfers are performed to the extent possible.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Renfrew Region.

6.1 Transmission Capacity Needs

This is to assess a) adequacy of each station's load supply capacity which is mainly to inspect the step-down transformer ratings; and b) adequacy of transmission facility to deliver the power within the Region under normal and contingency conditions, which is mainly determined by circuit thermal rating and voltage profile.

6.1.1 Station Adequacy Assessment

Non-coincident peak load at each station is compared against corresponding transformer maximum continuous rating or 10-day LTR if the continuous rating is exceeded. The peak loads are all forecasted to happen in 2024. Table 2 compares the net peak load against transformer ratings at each station. It can be seen that all stations are adequate to supply the loads in studied period.

Table 2 Station Adequacy Assessment

Station	Transformers	Net Peak Load (MW)	Transformer Rating/LTR* (MW)
Cobden DS	T3	7.2	11.3
Cobden TS	T1/T2	27.1	37.5
Craig DS	T1/T2	12.2	15.9
Deep River DS	T1/T2/T3	11.1	23.8
Des Joachims DS	T1	3.3	11.3
Forest Lea DS	T1/T2	9.2	9.9
Mazinaw DS	T1	3.4	5.4
Mountain Chute DS	T1	1.0	11.3
Pembroke TS	T1/T2	49.1	49.6
Petawawa DS	T1/T2	14.3	14.8
Chalk River CTS***		10	N/A
Magellan Aerospace CTS***		3.1	N/A
Chenaux TS	T3/T4	101.7**	112.5
Des Joachims TS	T6/T7	57.1	112.5

*: LTR is listed only if the peak load exceeded transformer continuous rating
**: Including 19.4MW new load, all station MVAs add up arithmetically
***: Load customer owned transformers, capacity not assessed in this study

6.1.2 Transmission Facility Adequacy Assessment

Under normal condition with all elements in service and the D6-X6 in-line switch open, the study found that:

- All transmission circuits supplying the Region, namely D6, X6, X2Y and X1P have adequate capacity over the study period.

The projected regional peak loads can be supplied even if the local generations at Des Joachims GS and Chenaux GS are out of service. In the X6/X2Y corridor, loss of one circuit (including breaker failure condition to cause additional loss of Chenaux generation) would not cause overload or under-voltage on the accompanying circuit. .

6.2 System Reliability, Operation and Restoration Review

- The Region’s total coincidental peak load is less than 150MW, therefore load loss violation due to configuration does not apply in this assessment.
- All loads are expected to be restored within 8 hours.
- The most critical contingency in the Region would be loss of 230kV circuit X1P which would produce an island at Chenaux. Stable islanding operation might be

achieved depending on pre-contingency flow and generation rejection arming. Reliability data recorded 13 X1P non-planned outages in past ten years, among which seven events show stable islanding operations before the system was paralleled back to the grid. In another two events the island collapsed after more than one hour of operation. The performance is expected to be unchanged in the study period.

- Studies show that under this contingency, Des Joachims TS may not be able to radially supply all the loads in the Region, under peak load conditions.
- Due to the fact that the loads are supplied via radial circuits and the Region is prone to storms, extended outages on D6 were experienced in the past (in 2011 for example). Further, outage analysis indicated that the most common cause for sustained outages was under severe storm. This issue cannot be addressed by building additional line in the same right-of-way. As a result, improved vegetation management and outage responses have effectively reduced sustained outages considerably in recent years. Table 3 lists sustained outage records of D6 in past five years.

Table 3 Outage Records of D6 from 2011 to 2015

Year	No. of Sustained Outages	Cumulative Duration (min)	Causes
2015	1	367	Conductor Broken
2014	1	5	Human Error
2013	3	1381	Isolated Electrical Storm
2012	1	1341	Tree Contact
2011	4	7792	Tree Contact

Studies show that under D6 terminal outage at the Des Joachims terminal, load can be restored by transferring D6 to Chenaux TS 115kV via X6 supply. Note, there is a maximum limit of 125 MW, which is the peak regional load in 2015, that can be supplied radially from Chenaux.

a) The following potential needs will be monitored and assessed in the next Regional Planning cycle for the Renfrew Region:

- Hydro One and the LDCs will continue to monitor and assess the load restoration performance under X1P and D6 outages.

- Major Hydro One facilities and equipment are continually monitored to ensure their safe and reliable operation. Circuit X1P is one of these facilities and, as such, its performance is monitored by Hydro One's Ontario Grid Control Centre (OGCC) in Barrie. OGCC's records will be reviewed regularly to ascertain the adequate performance of this circuit. The next planning cycle will take place in five years however, if the performance of X1P fall below adequate levels the Hydro One will undertake to assess and address this issue with the LDCs.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Section 3.2 lists the sustainment initiatives that are currently planned for the replacement of any aged transformers. There are no major line replacement plans scheduled in the near term in this region.

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team's recommendations are as follows:

No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region. Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

8 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: January 2016 – June 2017
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

9 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

APPENDIX A. LOAD FORECAST

Table A-1: Station Net Load Forecast (MW)

Transformer Station Name	Rating (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	11.3	6.6	6.7	6.7	6.8	6.8	6.9	6.9	7.0	7.1	7.2
Cobden TS T1/T2	37.5	25.8	25.9	26.0	26.0	26.2	26.5	26.6	26.8	26.9	27.1
Craig DS T1/T2	15.9	11.2	11.3	11.3	11.4	11.6	11.7	11.9	12.0	12.1	12.2
Deep River DS T1/T2/T3	23.8	10.9	11.0	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.1
Des Joachims DS T1	11.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Forest Lea DS T1/T2	9.9	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.2	9.2
Mazinaw DS T1	5.4	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.4
Mountain Chute DS T1	11.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0
Pembroke TS T1/T2	49.6	46.0	46.3	46.5	46.7	47.1	47.6	48.0	48.3	48.7	49.1
Petawawa DS T1/T2	14.8	12.8	13.1	13.2	13.4	13.6	13.8	13.9	14.1	14.2	14.3

Table A-2: Regional Coincidental Net Load Forecast (MW)

Transformer Station Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8
Cobden TS T1/T2	25.5	25.5	25.7	25.8	25.9	26.1	26.3	26.5	26.8	27.1
Craig DS T1/T2	11.1	11.2	11.3	11.3	11.4	11.5	11.6	11.8	11.9	12.1
Deep River DS T1/T2/T3	10.8	10.7	10.8	10.8	10.8	10.8	10.8	10.9	11.0	11.0
Des Joachims DS T1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2
Forest Lea DS T1/T2	9.0	9.0	9.1	9.0	9.0	9.0	9.1	9.1	9.2	9.2
Mazinaw DS T1	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Mountain Chute DS T1	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Pembroke TS T1/T2	38.7	38.9	39.3	39.6	39.9	40.3	40.8	41.3	42.0	42.6
Petawawa DS T1/T2	5.0	5.2	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3
Total Regional Load	125.2	127.2	128.0	128.2	128.6	129.3	130.3	131.4	132.7	133.8

Hydro One Network Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345.5420
Ajay.Garg@HydroOne.com

St. Lawrence Region

Regional Infrastructure Plan ("RIP")

July 22nd, 2016

Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)

The St Lawrence Region covers the southeastern part of Ontario bordering the St Lawrence River. The region starts at the Gananoque in the West and extends to the inter-provincial boundary with Quebec in the East..

The Needs Assessment ("NA") report for the St. Lawrence region was completed in April, 2016 (see attached). The report concluded that no regional planning needs were identified for the region at this time.

There are no other major development projects planned for the ST. Lawrence Region over the near and mid-term.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no regional planning was required, this letter and the attached NA report will be deemed to form the ("RIP") for the St. Lawrence Region.

The next regional planning cycle for the region is expected to be undertaken in five years form the start of this planning cycle (2015) or earlier if new needs emerge in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: St Lawrence

Date: April 29, 2016

Prepared by St Lawrence Region Study Team

St Lawrence Region Study Team

Company
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the St Lawrence region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	St Lawrence (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	March 1, 2016	**END DATE**	April 29, 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the St Lawrence Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the St Lawrence Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3. The St Lawrence Region belongs to Group 3. The NA for this Region was triggered on March 1, 2016 and was completed on April 29, 2016.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2025. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the Independent Electricity System Operator (IESO) and Hydro One transmission provided information for the St Lawrence Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2016 to 2025). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. 230/115 kV Autotransformers

The 230/115kV Autotransformers at St Lawrence TS are adequate over the study period for the loss of a single 230/115kV unit

B. Transmission Lines & Ratings

The 230kV lines are adequate over the study period. A Special Protection Scheme is in place to reject generation at Beauharnois GS and/or Saunders GS under post contingency conditions to ensure the loading on the St Lawrence to Hinchinbrooke TS 230KV circuits are within ratings.

The 115kV lines are adequate over the study period to supply the forecasted load. The section of the 115kV lines L2M/L1MB between St Lawrence TS and Lunenberg Jct may be overloaded under light load conditions and high DG and Cardinal Power generation, for the loss of the companion circuit. Since 2012, Morrisburg TS has been restricted and no additional generation is accepted. At the same time, this situation is also mitigated using the Cardinal Power CGS run back scheme or by limiting generation dispatch during these light load conditions. No further action is required.

C. 230 kV and 115 kV Connection Facilities

The 230kV and 115kV connection facilities in this region are adequate over the study period.

Inadvertent breaker operation (IBO) at Cardinal Power on either L1MB or L2M can result in Morrisburg TS transformers exceeding their reverse flow limits and/or cause a transformer to be loaded beyond ratings at Dyno Nobel CTS. Morrisburg TS has been restricted and no additional generation is accepted since 2012. This situation is also mitigated by using Cardinal Power runback scheme. No further action is required.

System Reliability, Operation and Restoration Review

Based on the gross coincident load forecast, the loss of one element does not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period. No action is required.

Chesterville TS missed its delivery point performance standard in recent years due to momentary outages resulting from severe weather patterns. The delivery point performance at Chesterville TS will be assessed and monitored to determine if corrective actions are required. No further action is required as part of regional planning.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following sustainment work is currently planned by Hydro One in the region:

- Morrisburg TS: components replacement (2019 in service)
- Smiths Falls TS: components replacement (2021 in service)
- St Lawrence TS: components replacement (2024 in service)

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

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1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the St Lawrence Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the St Lawrence Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs if straight forward wires solutions can address a need. Ultimately, assessment and findings of the local plans are incorporated in the RIP for the region.

This report was prepared by the St Lawrence Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1 Study Team Participants for St Lawrence Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the St Lawrence Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The St Lawrence Region belongs to Group 3.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the St Lawrence Region over an assessment period of 2016 to 2025. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

St Lawrence Region Description and Connection Configuration

The St Lawrence Region covers the southeastern part of Ontario bordering the St Lawrence River. The region starts at the Gananoque in the West and extends to the inter-provincial boundary with Quebec in the East.

The western part of the region is supplied from Hydro One owned stations connected to the 230kV network. The reminder of the region is supplied from Hydro One stations connected to the 115kV network except for St Lawrence TS which is supplied from 230kV.

The City of Cornwall is supplied by Fortis Ontario with transmission lines from Quebec and is not included in this Region. A map of the region is shown below in Figure 1.

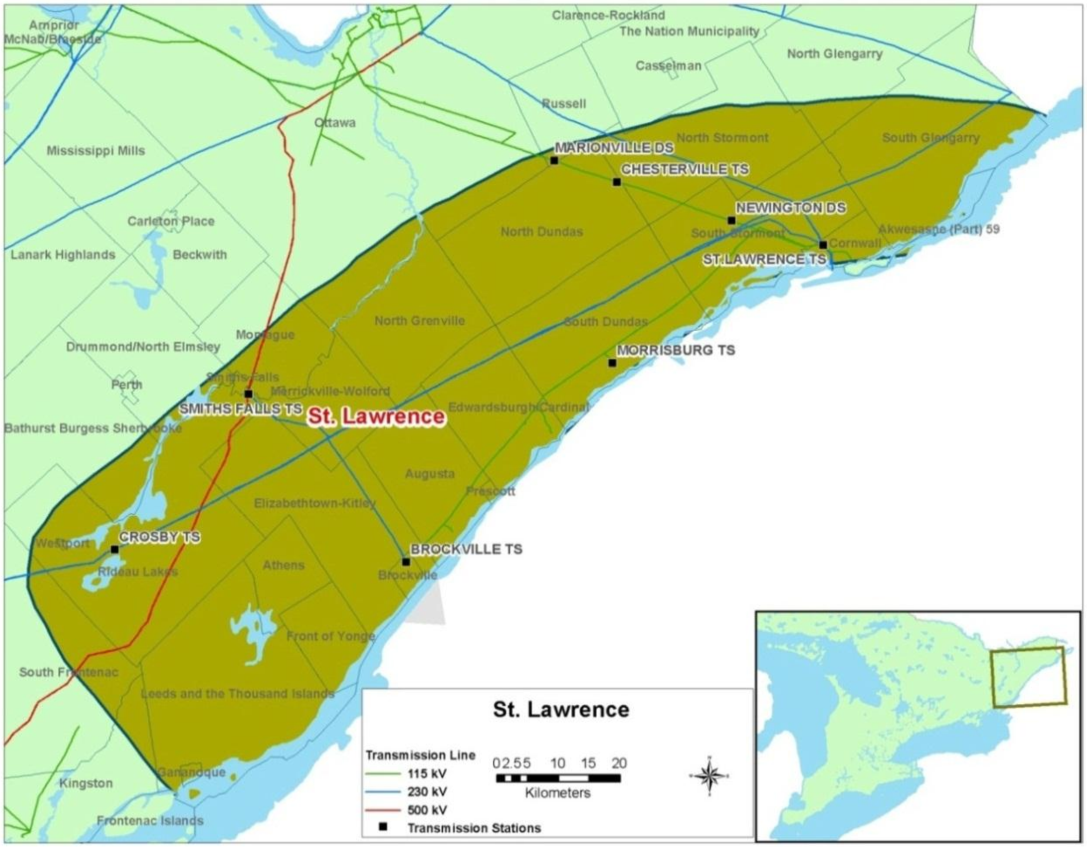


Figure 1 Map of St Lawrence Regional Planning Area

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. The major source of supply for this region is OPG's Saunder Hydro Electric station which connects to St Lawrence TS 230kV yard.

This region has the following three local distribution companies (LDC):

- Hydro One Networks (Distribution)
- Cooperative Hydro Embrun Inc. (embedded in Hydro One Distribution)
- Rideau St Lawrence Distribution Inc. (embedded in Hydro One Distribution)

Table 2 Transmission Lines in the St Lawrence Region

115kV circuits	230kV circuits	Hydro One Transformer Stations
L1MB, L2M, L5C[1]	L20H, L21H, L22H, L24A[2], B31L[2]	Brockville TS, Chesterville TS, Crosby TS Morrisburg TS, Newington DS, Smith Falls TS St Lawrence TS*

*Stations with Autotransformers installed

[1] L5C is normally o/s, and used as a backup supply for the City of Cornwall.

[2] L24A and B31L connect to St Lawrence TS but do not have load customers connection.

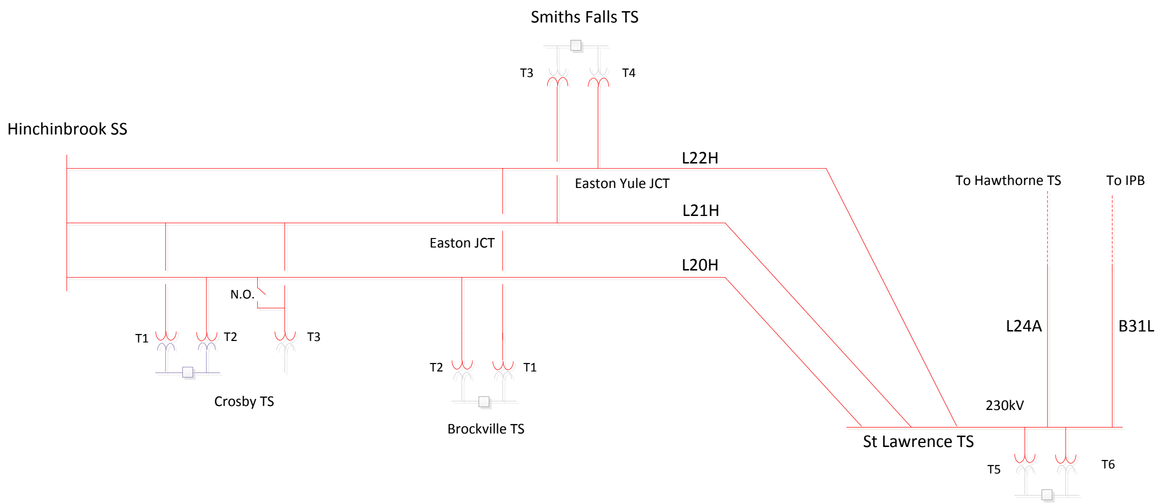


Figure 2 Single Line Diagram 230 kV St Lawrence Regional Planning Area

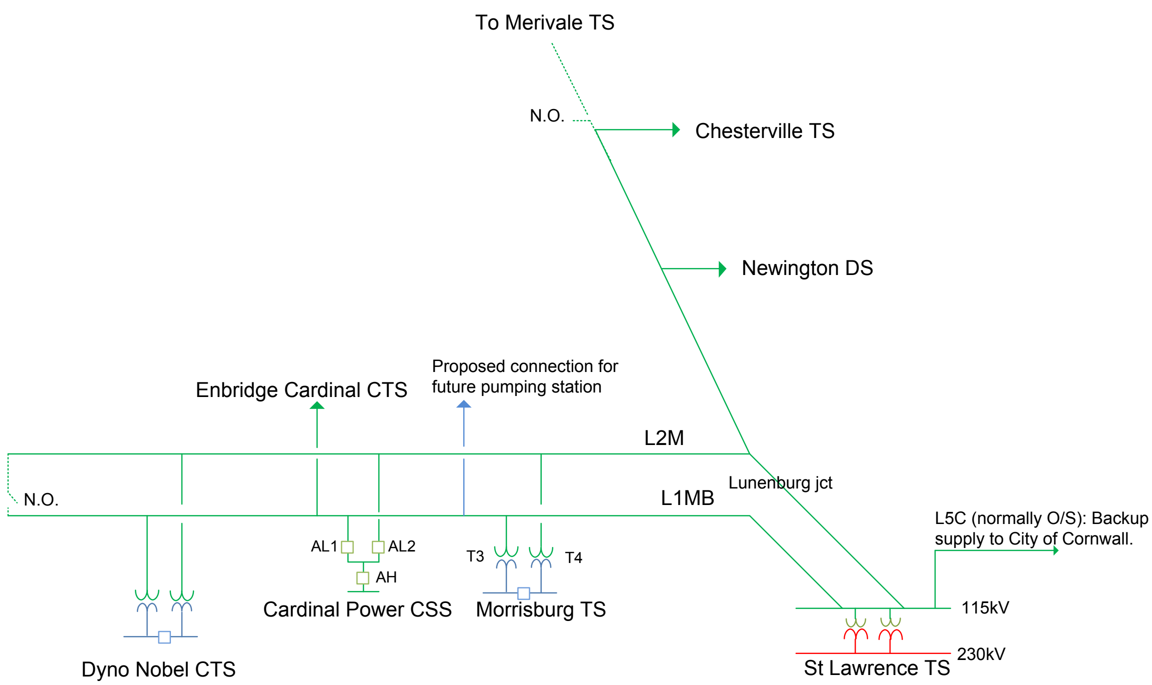


Figure 3 Single Line Diagram 115 kV St Lawrence Regional Planning Area

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- IESO provided:
  - i. Historical Ontario and regional coincident load station peaks, as well as individual station peaks.
  - ii. List of existing reliability and operational issues
  - iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2013-2015) net load and gross load forecast (2016-2025).
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

Load Forecast

As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.8% annually from 2016-2025.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to increase at an average rate of approximately 0.2% annually from 2016-2025.

Future Project

As shown in Figure 3, there is a proposal to connect a pumping station for the TransCanada Energy East project that will add 18MW of load to the area. The pumping station is planned to be connected to circuit L1MB close to Morrisburg TS. The current in-service date is 2021.

5 NEEDS ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

1. The Region is winter peaking so this assessment is based on winter peak loads.
2. Saunders GS was assumed to generate at its average 98% of time dependable hydro generation level which is 542MW.
3. Forecast loads are provided by the Region's LDCs

4. Load data was requested from industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
5. Accounting for (3), (4), above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to verify each station is within its rating to supply the forecasted load. The net forecast was used for system study.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the winter 10-Day Limited Time Rating (LTR). Winter LTR ratings were reviewed.
8. Extreme weather scenario factor at 1.0582 was also assessed for capacity planning over the study term.
9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their winter long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using winter loading with winter 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 RESULTS

230/115 kV Autotransformers
The 230/115kV Autotransformers at St Lawrence TS are adequate over the study period for the loss of a single 230/115kV unit

Transmission Lines & Ratings

230kV Lines
The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

There is a generation rejection scheme in place that can runback Saunders GS and/or Beauharnois GS under post-contingency conditions. This scheme ensures that the St Lawrence to Hinchinbrooke TS lines are not overloaded under peak summer conditions.

115kV Lines
Under the assumptions made for regional planning, the 115kV lines are adequate over the study period for the loss of a single circuit in the Region.

The following operating issues have been previously in the SIA/CIA done for Cardinal Power G3 Expansion [4, 5]:

Under light load condition and with all distributed generation in the area and the Cardinal Power generation at maximum output the section of the L1MB/L2M line between St Lawrence to Lunenburg JCT can be loaded beyond its short time emergency (STE) rating for loss of either circuit.

To manage the situation, Morrisburg TS has been restricted to accept new generation connection since 2012. In addition, there is Cardinal Power's runback scheme will reduce the plant output following the loss of either circuit and hence reduce the post-contingency loading on either of the L1MB/L2M lines. However since the lines could be loaded beyond their STE, measures such generation re-dispatch is implemented by the IESO as per the Cardinal Power G3 Expansion studies [4, 5].

230 kV and 115 kV Connection Facilities
A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station winter peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario.

Reverse Power Flow

At Morrisburg TS, under light load condition and high distributed and directly connected generation, a reverse power flow issue was identified in the Cardinal Power G3 Expansion SIA/CIA [4, 5]. This situation occurs if one of the line breakers at Cardinal Power has an inadvertent opening (IBO). This IBO results in all of Cardinal Power's generation being sent to one line, which causes reverse power at Morrisburg TS beyond its maximum limit. As noted previously, since 2012, additional generation connection has been restricted at Morrisburg TS to manage the reverse power flow at the station.

Dyno Nobel CTS

Under the same conditions mentioned above, an IBO at Cardinal Power can also result in power flow through the Dyno Nobel CTS to exceed their rating [4, 5].

For Morrisburg TS and Dyno Nobel CTS transformer loading issues, Cardinal Power run back scheme is triggered to reduce the flows to within equipment ratings as it was outlined in the SIA and CIA [4,5]. No further action is recommended within the scope of this regional planning.

7 SYSTEM RELIABILITY, OPERATION AND RESTORATION

Based on the gross coincident load forecast, the loss of one element does not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW for the duration of the 10-year study period.

Chesterville TS and Newington DS are on single supply from L2M for a combined gross load of 50MW in 2025. If the supply from St Lawrence TS becomes unavailable, these two stations can be supplied from Merivale TS.

All loads in the St Lawrence area can be restored within the 8 hour requirement.

IESO indicated in their unsupplied energy report that the 115kV area did not meet its target in the past. Chesterville TS missed its customer delivery point target (frequency of interruption) in recent years due to momentary outages seen as a result of severe weather patterns. Hydro One will review and monitor its supply point performance at Chesterville TS to determine if corrective measures are required. No further actions required as part of regional planning.

8 AGING INFRASTRUCTURE AND REPLACEMENT PLAN OF MAJOR EQUIPMENT

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables during the study period. At this time the following sustainment work is planned for the stations in the area:

Morrisburg TS: Protection upgrade, 44kV breakers (2019 in service)

Smiths Falls TS: Protection replacement, battery and charger, switches (2021 in service)

St Lawrence TS: Replacement of oil breakers at 230kV, 115k, and 44kV; replacement of AC/DC station service supplies; and protection upgrade work. (2024 in service)

The facilities at these stations are adequate and there is no need to increase the equipment rating.

9 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

10 NEXT STEPS

No further Regional Planning is required at this time. The St Lawrence Region Regional Planning will be reassessed during the next planning cycle or at any time should unforeseen conditions or needs warrant to initiate the regional planning for the region.

11 REFERENCES

1. Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
2. IESO 18-Month Outlook: March 2014 – August 2015
3. IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
4. Cardinal Power 15MW Plant Expansion SIA (2011-432)
5. Cardinal Power 15MW Plant Expansion CIA

APPENDIX A: Load Forecast

Winter Load: Normal Weather Condition.

Station		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Brockville	Non Coincidental Gross		135.8	136.7	137.9	139.7	141.4	142.5	143.6	144.6	145.6	146.5
	CDM (MW)		1.1	1.9	3.2	4.3	5.4	6.3	7.0	7.5	8.2	8.8
	DG (MW)	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	Non Coincidental Net	134.3	132.9	132.8	132.8	133.5	134.2	134.4	134.6	135.2	135.5	135.8
	Coincidental Net	115.6	115.9	115.9	115.9	116.4	117.0	117.2	117.4	117.9	118.2	118.5
Chesterville	Non Coincidental Gross		42.0	42.5	43.2	44.1	45.0	45.7	46.3	46.9	47.6	48.2
	CDM (MW)		0.3	0.6	1.0	1.4	1.7	2.0	2.3	2.4	2.7	2.9
	DG (MW)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Non Coincidental Net	41.2	40.6	40.9	41.2	41.7	42.3	42.7	43.0	43.5	43.9	44.3
	Coincidental Net	41.2	41.6	41.9	42.2	42.8	43.3	43.7	44.1	44.5	44.9	45.3
Crosby	Non Coincidental Gross		28.8	29.0	29.2	29.6	30.0	30.2	30.4	30.6	30.8	31.0
	CDM (MW)		0.2	0.4	0.7	0.9	1.1	1.3	1.5	1.6	1.7	1.9
	DG (MW)	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
	Non Coincidental Net	28.5	25.9	25.9	25.9	26.1	26.2	26.2	26.3	26.4	26.5	26.5
	Coincidental Net	18.9	18.9	18.9	18.9	19.0	19.1	19.1	19.2	19.2	19.3	19.3
Morrisburg	Non Coincidental Gross		61.5	61.7	62.1	62.7	63.3	63.7	64.0	64.3	64.6	64.9
	CDM (MW)		0.5	0.9	1.4	1.9	2.4	2.8	3.1	3.3	3.6	3.9
	DG (MW)	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
	Non Coincidental Net	60.0	52.6	52.4	52.3	52.3	52.5	52.4	52.4	52.5	52.5	52.5
	Coincidental Net	53.9	53.9	53.8	53.6	53.7	53.8	53.8	53.8	53.9	53.9	53.9
Newington	Non Coincidental Gross		1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1
	CDM (MW)		0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	DG (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non Coincidental Net	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	Coincidental Net	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Smiths Falls	Non Coincidental Gross		124.2	125.1	126.6	128.1	128.8	129.5	130.2	130.8	131.4	132.1
	CDM (MW)		1.0	1.8	2.9	4.0	4.9	5.7	6.4	6.8	7.4	7.9
	DG (MW)	3.9	4.0	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
	Non Coincidental Net	122.5	119.2	118.8	119.2	119.5	119.4	119.3	119.3	119.5	119.5	119.6
	Coincidental Net	112.7	112.8	112.4	112.7	113.1	113.0	112.9	112.8	113.0	113.1	113.2
St Lawrence	Non Coincidental Gross		44.5	44.7	45.1	45.5	45.6	45.7	45.8	45.9	46.0	46.0
	CDM (MW)		0.4	0.6	1.0	1.4	1.7	2.0	2.2	2.4	2.6	2.8
	DG (MW)	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
	Non Coincidental Net	44.2	41.6	41.5	41.5	41.5	41.3	41.1	41.0	40.9	40.8	40.7
	Coincidental Net	43.0	42.9	42.8	42.8	42.8	42.6	42.4	42.3	42.2	42.1	42.0

APPENDIX B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

1.3 (5.2.2) CUSTOMER ENGAGEMENT – HOW HYDRO ONE'S INVESTMENT PLAN INCORPORATES THE NEEDS OF CUSTOMERS

Hydro One's transmission system serves a diverse customer base made up of: (i) electricity generators who deliver power to the transmission system; (ii) distributors who deliver power to direct customers; and (iii) end-users such as mining and industrial enterprises that use the power themselves at transmission level voltage.

Hydro One's customers are located throughout the province. Serving customers in northern and rural areas presents different challenges due to sparse populations, remote location of assets and often, single-phase circuits. Conversely, customers in non-rural, more populated areas often share multi-circuit lines with other transmission customers. Indeed, the three customer groups described above often have needs and preferences unique to their segement. Engaging with these different customer segments requires a number of channels for customer engagement.

Through its broad range of customer engagement activities, Hydro One has developed a clear and specific understanding of the outcomes that its transmission customers care most about, as well as the level of spending and mix of investments that customers would most like to see included in Hydro One's investment plan. The feedback received from customers through these engagement activities is an important and direct input into Hydro One's investment planning process. Consequently, Hydro One's capital expenditure plan, as set out in Section 3 of this Transmission System Plan ("TSP"), is closely aligned with and highly responsive to the customer needs and preferences that Hydro One has identified.

This section describes the various initiatives through which Hydro One has developed an understanding of the specific needs and preferences of customers, including a customer engagement survey that was carried out specifically to inform this TSP. The feedback received from these processes has contributed to Hydro One's understanding of the outcomes that are of the greatest value to its transmission customers. This feedback has been inputted directly into Hydro One's investment planning process. The results of the customer engagement survey have been re-affirmed by feedback received from subsequent ongoing customer engagement activities.

1.3.1 (5.2.2 A) IDENTIFICATION OF CUSTOMER NEEDS AND PREFERENCES

Hydro One collects feedback from transmission customers through the following initiatives:

- Customer Engagement Surveys;
- Large Customer Account Management;
- Ontario Grid Control Centre's ("OGCC") Customer Operating Support Group;
- Large Customer Conferences;
- Oversight Committees and Working Groups;
- Customer Satisfaction Surveys and Research; and
- Focussed Planning Meetings with Customers.

These initiatives are firmly integrated into Hydro One's business practices and are fundamental to the way Hydro One interacts with its customers and carries out its transmission business. The Customer Engagement Survey has been a valuable process for supplementing, formalizing and validating the feedback Hydro One collects through ongoing engagement activities, and for formalizing the manner in which this feedback is integrated into investment planning.

Figure 1 below is a summary of key priorities for customers based on customer engagement and specific steps taken to incorporate customer considerations into the investment planning methodology and overall investment strategy.

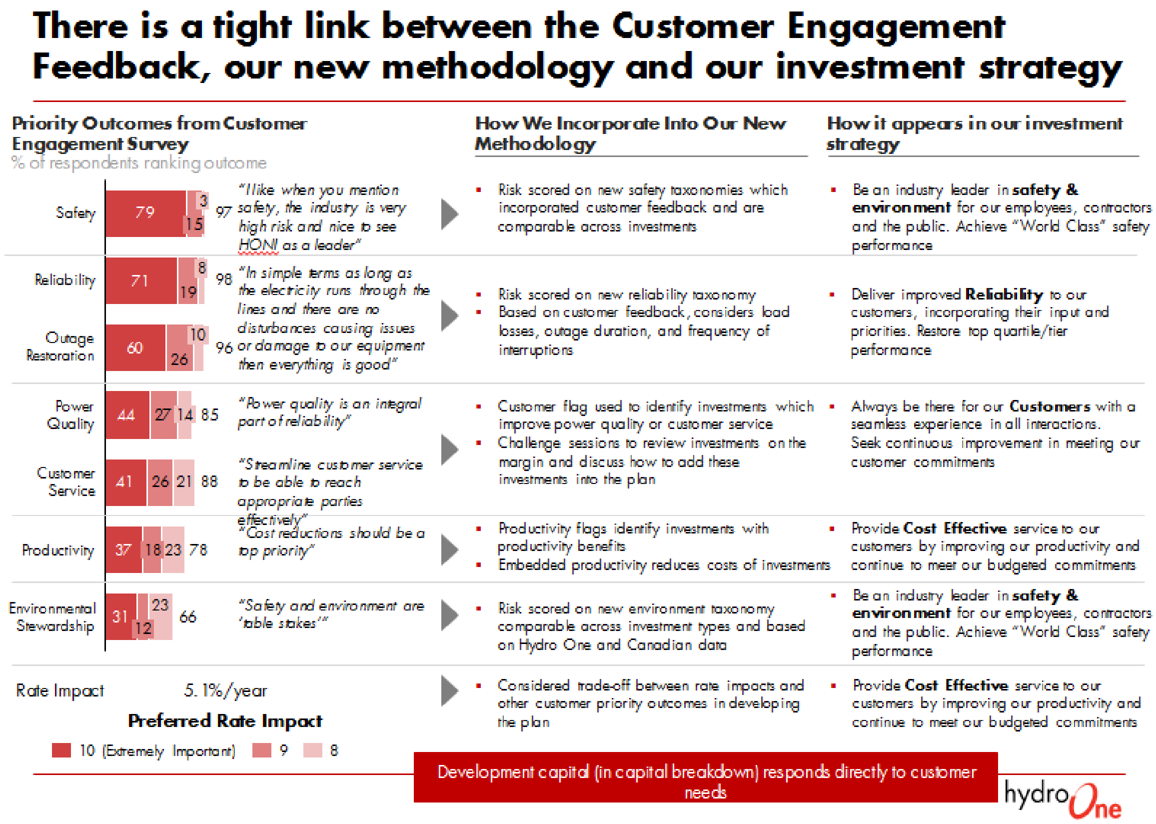


Figure 1 - Incorporation of Customer Considerations Into the Investment Strategy

Section 2.1 of the TSP explains how customer feedback is considered in Hydro One's investment planning process. Section 3.2 of the TSP explains how the proposed capital expenditure plan reflects the outcomes valued by customers.

1.3.2 (5.2.2 A) CUSTOMER ENGAGEMENT SURVEY

The Transmission Customer Engagement Survey process enables Hydro One to engage in formal discussion with its transmission customers for the purpose of obtaining feedback to inform Hydro One's investment planning process. This process aligns with Hydro One's vision to be a customer-focused commercial entity with a transmission investment plan that will drive the outcomes that customers value by demonstrating responsiveness to identified customer needs and preferences, including how to make trade-offs between outcomes and costs.

1.3.2.1 BACKGROUND AND OBJECTIVES

In 2016, Hydro One introduced a Transmission Customer Engagement Survey process. The approach taken by Hydro One in its 2017 survey was improved by incorporating lessons learned and addressing comments made about the 2016 survey.

In 2017, Hydro One engaged Innovative Research Group ("IRG"), an experienced third party research and consultation firm, to develop and implement a second iteration of the Transmission Customer Engagement Survey process (as outlined in Appendix 1). Content for the 2017 Transmission Customer Engagement Survey incorporated lessons learned from the 2016 Survey process, including feedback received from the OEB and interveners in the last transmission rate proceeding (as outlined in Appendix 2). This content established a framework for Hydro One to obtain useful, credible and unbiased information to guide the investment and business planning efforts that underpin this TSP.

The scope of the 2017 survey was also expanded beyond the level of investments. In 2016, customers were mostly asked what funding level was appropriate. In 2017, the survey sought customer feedback regarding which investments should be prioritized by evaluating what outcomes customers valued.

Through the 2017 Transmission Customer Engagement Survey process, Hydro One further developed its understanding of the needs and preferences of its transmission customers that were considered at various points in Hydro One's investment planning process. Hydro One carried out this customer engagement process early in the planning process to allow sufficient time for customer needs and preferences to be considered and integrated into the transmission investment planning and business planning processes.

Detailed results of the 2017 process are set out in the IRG Customer Engagement Report provided in Attachment 1. Appendix 1 outlines the process and timing of the engagement survey, and Appendix 2 outlines the feedback heard from OEB staff and interveners regarding the 2016 process and the specific steps taken to address that feedback as part of the 2017 process.

1.3.2.2 (5.2.2 B) SUMMARY OF CUSTOMER NEEDS AND PREFERENCES

All transmission-connected customers were invited to participate in Hydro One's customer engagement survey. Over 100 Hydro One transmission-connected customers participated in the 2017 Transmission Customer Engagement Survey, reflecting a participation rate of 66%. This improved level of participation reflected the involvement of 103 out of Hydro One's 156 transmission-connected customers including a large number of LDCs. These 2017 participation rates were 51% higher than those of the 2016 customer engagement.

Hydro One's Transmission Customer Engagement Survey process yielded valuable feedback concerning the specific needs and preferences of its transmission-connected customers to shape Hydro One's investment plans. The prioritized list of outcomes valued by Hydro One's transmission customers is presented in the figure below (reproduced from Attachment 1):

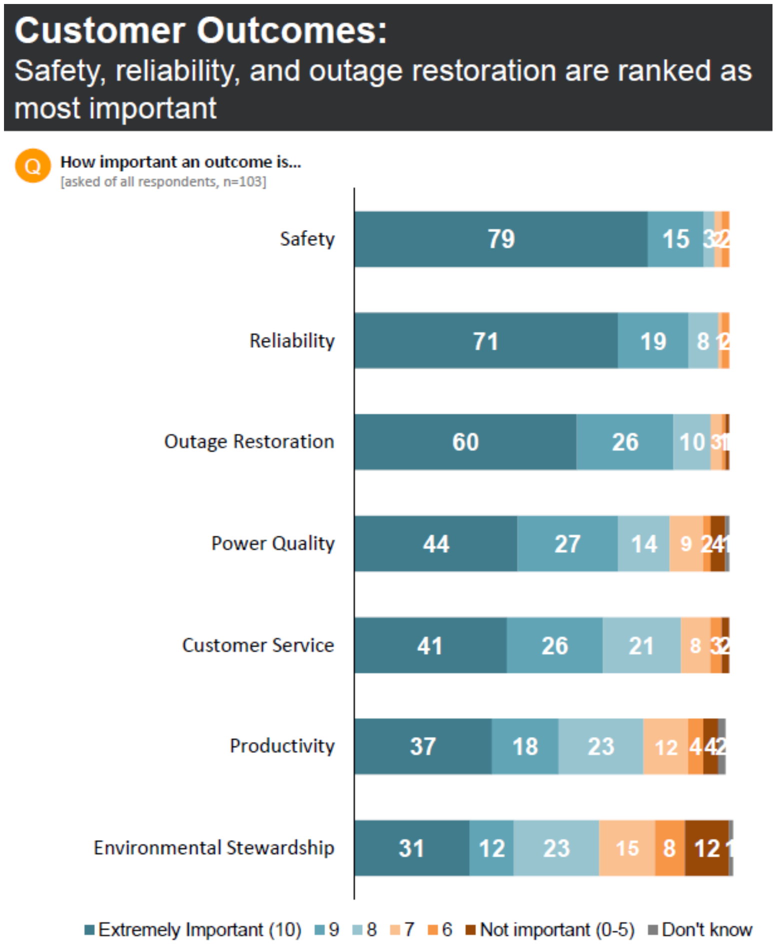


Figure 2 - Customer Outcomes

The key messages and results received by Hydro One from the 2017 Transmission Customer Engagement Survey are as follows:

- Safety, reliability, and outage restoration are customers' top prioritized outcomes;
- All customer segments prefer to see investments spread out over time versus investing now with higher rates in the short term and lower future increases or delaying investments with lower rates in the short term and higher future rates;
- Reducing the frequency of outages is more important than reducing the duration of outages. However, the most important issue is to reduce the number of day-to-day interruptions;

- When presented with several investment scenarios, the majority of customers preferred investment levels in line with the investment plan that was before the OEB in the Prior Proceeding by at least a three to one margin. It is seen as reflective of the current approach which has served the system well, and a less risky option; and
- About half of end-user participants (19 of 38) rate power quality as an “extremely important” outcome.

Despite different perspectives, most customers agreed that improvements in both frequency and duration of outages are among their top needs. Power quality and transmission capacity were also raised as major issues facing customers, particularly in northern Ontario. Cost was also raised at various times throughout the survey. The desire for good reliability at a competitive or low cost was universal.

1.3.3 (5.2.2 A) CUSTOMER SATISFACTION SURVEYS AND RESEARCH

In addition to Hydro One's customer engagement surveys, Hydro One regularly solicits feedback from customers through a variety of channels to be leveraged throughout Hydro One's planning process.

1.3.3.1 CUSTOMER SATISFACTION SURVEYS

Since 1999, Hydro One has been collecting feedback from transmission customers through an annual customer satisfaction research process. The customers surveyed are critical to the success of Hydro One's business, and are also critical to the communities in which they operate. The trending of results over time assists Hydro One in identifying areas to improve transmission customer satisfaction. Hydro One uses this data to inform and improve business practices and stay informed about the trends that matter most to transmission customers. Customer Satisfaction scores are also included in Hydro One's Corporate Team Scorecard (Exhibit F, Tab 4, Schedule 1, Attachment 4) and Hydro One's proposed Transmission Scorecard (as described in Section 1.5 of the TSP).

This research is conducted by independent expert customer research firms. The most recent iteration of this research was carried out and reported on by Innovative Research Group in 2018 and is described in Section 1.5 of the TSP.

The objectives of the Large Transmission Customer survey are to measure the level of customer satisfaction, and to monitor Hydro One's performance in four dimensions of satisfaction among customers: Price, Customer Service, Product Quality/Reliability and Relationship. The survey measures customer perceptions of the Company (whether they have interacted with Hydro One recently or not), with a specific focus on how well the Company meets expectations and delivers on critical success factors. The survey is administered to transmission-connected Generators, End Users and all LDCs. The customer survey research is used to evaluate the overall satisfaction levels of these customers groups, and to better understand their perceptions of Hydro One.

Figure 3 illustrates the trend of the overall satisfaction results. In 2018, Overall Satisfaction was at the highest point in the past seven years at 90%, which is a 12% increase since 2016. The increase in overall satisfaction can be attributed to LDCs and generation customers. The main driver identified through analysis for higher customer satisfaction was customer communication and key account managers. The identified driver correlated with lower satisfaction was the ability to recall a planned outage. Additional information can be found in TSP Section 1.5 and the complete 2018 survey results can be found in Attachment 5 to this exhibit. The greatest dimension of high customer satisfaction was customer service, with 93% satisfaction with communications methods, 93% satisfaction with customer service overall and 90% satisfaction with key account services from account executives. A majority, 60%, are satisfied with Hydro One’s product. Some dimensions with lower product satisfaction include number of unplanned outages, a dimension 50% of customers are dissatisfied with.

Figure 3 from Exhibit B1, Tab 1, Schedule 1, Section 1.5 – Overall Customer Satisfaction, Corporate Survey (% satisfied)

1.3.3.2 (5.2.2 B) ONTARIO GRID CONTROL CENTRE TRANSMISSION CUSTOMER SURVEY

Hydro One's Ontario Grid Control Centre ("OGCC") has surveyed satisfaction among its medium and large business customer satisfaction since 2013. The main objective of the survey is to determine key dimensions of satisfaction, strengths, and opportunities and to improve customer service policies, service delivery processes and communications in the areas of accountability of the OGCC such as outage planning and interruption restoration information. Overall satisfaction with OGCC has improved over the past year (98% in 2018 vs. 94% in 2017). The greatest driver of OGCC customer satisfaction was communications and responsiveness. Hydro One's average performance over the past five years was 90 per cent, and the overall trend indicates that satisfaction with outage planning procedures is improving. Over the rate period, Hydro One plans to maintain its historical average, targeting 90 per cent satisfaction with outage planning procedures.

Additional information can be found in TSP Section 1.5. The complete 2018 OGCC customer survey results are provided as Attachment 6 to this exhibit.

1.3.4 (5.2.2 A) ONGOING CUSTOMER ENGAGEMENT

Hydro One believes that understanding customers, and their needs, is critical to a successful business. Hydro One engages with customers regularly and through different mechanisms. Customer needs can be categorized as either (i) initial connection needs, or (ii) needs of connected customers.

Initial connection needs are generally identified either through the Hydro One customer connection process or by need assessments and customer consultations under the regional planning process, as described in TSP Section 1.2. The regional planning process ensures that needs are assessed and identified by Hydro One in conjunction with customers, the IESO and LDCs.

Once connected, customer needs are identified by continuous monitoring of the power system. Hydro One planners continuously engage with customers (e.g. LDCs, industrial and commercial transmission-connected customers) to discuss and solicit feedback on investments to address end of life asset replacements. Open dialogue with customers during the planning stages of candidate investments ensures customers' needs and preferences are addressed in a collaborative manner, and it allows customers to have a voice regarding technical system requirements such as improved station configuration to enable greater operational flexibility, and changes in work execution practices and processes that impact customers. Customer feedback also provides valuable information that planners incorporate into the Investment Planning Process during the Asset Risk Assessment ("ARA") process (discussed further in TSP Section 2.1) to inform the development of investment candidates.

1.3.4.1 ONGOING CUSTOMER ENGAGEMENT SURVEY (RRFE)

Hydro One is implementing an Ongoing Customer Engagement Questionnaire that will quantify transmission customers' satisfaction regarding a variety of reliability focused measurements. The Questionnaire asks about customer satisfaction with Hydro One's current work program; satisfaction with outages, power quality, and reliability; investment priorities; unplanned outages mitigation and impact; and rate impacts.

Although the questionnaire asks customers to rank satisfaction of key indicators on a scale of 1-5, the survey also addresses specific preferences, asking customers if they would prefer shorter and more frequent outages or longer and less frequent outages, for example. Results of these questions will be inputted into Hydro One's Customer Relationship Management system, which keeps records of customer agreements, issues complaints, feedback and CSAT results. These questionnaire results will directly inform Investment Planning on problem areas that need to be mitigated, as well as broader customer preference trends to apply across the system. The questionnaire will be done on an annual basis to give planners a continuous source of customer information beyond CSAT scores, beginning in 2019.

Directly connected transmission customers currently receive an annual reliability report which summarizes historical and annual performance at transmission and distribution delivery points, describes investments recently made in the customer's area, investments planned in the customer's area and upcoming maintenance in the customer's area. The reliability report allows customers to provide informed input into customer engagement touch points, such as Hydro One's new Ongoing Customer Engagement Questionnaire.

1.3.4.2 LARGE CUSTOMER ACCOUNT MANAGEMENT

The Large Customer Account Management Group (formerly, "Customer Business Relations") provides customers with a single point of contact at Hydro One for all types of interactions. In particular, this group communicates with customers on matters that include customer connection requests, sustainment and system development plans and projects, and concerns regarding service levels or power quality.

Account Executives from Hydro One’s Large Customer Account Management Group meet with transmission customers on a regular basis to ensure that the needs of customers are identified and discussed, and action plans are developed to address these needs. If an action plan results in new or modified connection facilities and/or asset needs, then the Account Executive will directly communicate with the affected customer(s) to ensure a common understanding of the related connection process and contractual requirements, such as connection cost estimates and capital cost recovery agreements. Examples of investments included in this TSP that have resulted from direct communication by Account Executives in Hydro One’s Large Customer Account Management Group with customers, are Enfield TS and the Seaton MTS Connection. Hydro One’s transmission system planners developed candidate projects to address the customer needs identified in action plans. Risks associated with each of these candidate projects were considered throughout Hydro One’s investment planning process and resulted in the inclusion of the Enfield TS and Seaton MTS Connection projects in Hydro One’s capital expenditure plan.

Hydro One’s Account Executives proactively engage with transmission customers to review and coordinate planned outage activities to minimize impacts on customers and to optimize opportunities for both Hydro One and customers to plan and execute work on their respective facilities. The outcomes of these discussions are used as inputs to the OGCC’s Transmission System Outage (“TSO”) process to coordinate multiple work activities on the same equipment during a single outage, as discussed further below. Account Executives also participate in the OGCC’s meetings with customers to discuss planned outages and work as part of the regional planning process, discussed in TSP Section 1.2.

In 2018, Hydro One addressed the OEB’s finding that: “Hydro One should improve its internal institutional processes to better inform the transmission performance management system of distribution customers’ satisfaction level for the purpose of gauging what, if any, elements of transmission operation are the cause of any dissatisfaction".[1] In response, among other things, the Company began consolidating the service delivery model for its largest customers having a 2 MW demand or more including Hydro One's distribution-connected end use consumers. This change will introduce a similar level of customer service for Hydro One's Large Distribution Accounts ("LDA") that Hydro One's transmission-connected customers currently receive, including the assignment of Account Executives to LDA customers, tracking of customer information and interactions, and identifying opportunities for advocacy for these large customers across the company.

In particular, this approach will facilitate the consistent and more complete reporting of customer needs and preferences for use by planners, operators and customer service teams to consider when making transmission planning and investment decisions. Further details in respect of how Hydro One addressed the OEB's findings quoted above are set out in Appendices 1, 2 and TSP Section 1.5.2.

1.3.4.3 OGCC'S CUSTOMER OPERATING SUPPORT AND OUTAGE PLANNING GROUP

The OGCC's Customer Operating Support Group works directly with transmission customers to efficiently plan real-time outage operations, coordinate planned outages so Hydro One or the customer can complete required work, to respond quickly to unexpected outages, and to coordinate switching activities.

The Outage Planning Group organizes bi-annual customer meetings throughout the province to coordinate outage planning activities. These meetings are a key activity in Hydro One's TSO process. The OGCC sends reports, customized for individual customers that provide a rolling, one-year window of the planned outages that will affect

[1] EB-2016-0160, Decision and Order (November 1, 2017), pp. 38-39

the customer's delivery point. These reports contain information on outage start and end dates, the equipment involved, purpose, recall time and schedule profile. The reports provide an opportunity for customers to provide feedback. The Outage Planning Group also provides information on Hydro One's plans, particularly with respect to outages, for the balance of the year and/or the next scheduling year. During these meetings, customers may bring forward their own maintenance plans for their facilities, with a view to scheduling or bundling outages in a manner that minimizes the frequency and duration of outages for both the utility and the customer.

1.3.4.4 LARGE CUSTOMER CONFERENCE

Each year, Hydro One organizes and hosts a Large Customer Conference for all large transmission and large distribution (2 MW+) customers. The focus of the conference is to provide an opportunity for large customers to hear about Hydro One's plans and initiatives, ask questions, discuss their interests, and raise concerns with representatives and executives from several Hydro One lines of business. To ensure that the conference addresses the specific areas of interest for these customers, Hydro One seeks customer input prior to the conference to inform the conference agenda. This provides initial insights into the issues that are top of mind to Hydro One's large customers. At the conference, customers who are directly connected to the transmission system are presented with information about significant upcoming Hydro One initiatives that may affect them, including any technological changes they would need to be aware of or other potentially impactful initiatives.

In recent years, Hydro One has used these conferences as an opportunity to provide large customers with presentations about Hydro One's planned investments and activities. In addition, large customers are given an opportunity during each Large Customer Conference to meet with Hydro One staff, including Planning staff, to share information and raise concerns. In addition to Planning staff learning about customer needs and preferences through these informal conversations, feedback received during the conference, and through post-conference customer surveys, is subsequently provided to Planning for further consideration. Recent feedback suggests that customers would like to hear more about reliability, maintenance procedures and lowering recall time in outages.

1.3.5 (5.2.2 A) OVERSIGHT COMMITTEES AND WORKING GROUPS

Hydro One has established a number of oversight committees (and in the case of Metrolinx, a working group) to engage and obtain feedback from customers on topics with a high level of customer interest. Ongoing coordination with other entities is particularly valuable where there is a need for coordinated health and safety oversight. The purpose and value of the oversight committees is to ensure that the ongoing operational needs and preferences of these customer groups are accounted for in a timely and tactical fashion. The purpose of these oversight committee meetings is not expressly to direct investment plans, although the oversight committees can give an early insight as to future investment needs more generally. To date, Hydro One has established and maintains a number of oversight committees as follows.

1.3.5.1 SARNIA AREA RELIABILITY OVERSIGHT COMMITTEE

The Sarnia Area Reliability Oversight Committee consists of Hydro One staff and industrial and generation-connected customers and LDCs in the Sarnia Chemical Valley area. Chemical Valley customers include a large number of facilities and refineries with very sensitive manufacturing processes. The industry in the Sarnia area is particularly concerned with reliability and power quality such as loss of supply, loss of redundancy, and voltage fluctuations that can result in possible wide spread health and safety issues such as gas flares and cause very costly damage to customer manufacturing equipment and halt their processes. This committee meets twice a year to identify issues regarding reliability in the Sarnia Area and to review proposed annual work plans to ensure that issues will be addressed appropriately, having regard for the environmental and safety concerns of these customers.

1.3.5.2 LDC WORKING GROUP

Hydro One facilitates an LDC working group, which serves as a forum to update and communicate with LDCs on Hydro One’s transmission-related policies and practices, identify emerging issues, as well as solicit input to enhance customer experience. This group meets three to five times annually.

1.3.5.3 TORONTO HYDRO OVERSIGHT COMMITTEE

Hydro One holds quarterly Oversight Committee meetings with Toronto Hydro-Electric System Limited to identify and resolve issues and to coordinate efforts on capital projects and other matters. This forum allows the two utilities to coordinate their operations in a safe and efficient manner.

1.3.5.4 SWITCHYARD OVERSIGHT COMMITTEES

Hydro One facilitates and participates in switchyard oversight committees with Bruce Power Inc. and Ontario Power Generation Inc. These committees assist the parties in overseeing and coordinating matters of mutual interest, such as interface equipment, procedures and policies that pertain to Hydro One equipment at nuclear generation facilities. These committees ensure the safe and efficient operation of switchyards at Ontario's nuclear generation facilities, help maintain compliance with legal requirements, and allow for the efficient coordination of capital projects and other matters. These committees each meet approximately three times each year.

1.3.5.5 METROLINX WORKING GROUP

Hydro One's Metrolinx Working Group provides a forum to reviews issues arising during the large scale transportation infrastructure work that Metrolinx is undertaking in Ontario. This working group is made up of staff from Hydro One's Large Account Management, Real Estate, and Transmission Planning groups and staff from Metrolinx. The working group reviews and addresses customer escalations arising from the Metrolinx work program and ensures that issues are addressed in a timely manner.

1.3.5.6 HYDRO OTTAWA OVERSIGHT COMMITTEE

The Hydro Ottawa Oversight Committee was established in 2018 and provides a forum for Hydro Ottawa and Hydro One to meet twice a year to identify and resolve any issues and to ensure safe and efficient operations between Hydro One and Hydro Ottawa. Meetings also allow the parties to coordinate efforts relating to capital projects and other matters.

1.3.6 (5.2.2 A) INCORPORATING CUSTOMER NEEDS INTO THE PLAN

Insights from recent surveys reveal customers are seeking improvements in the following areas:

- Safety, reliability, and outage restoration are customers' top prioritized outcomes;
- All customer segments prefer to see investments evenly spread out over the long term;
- Reducing the frequency of outages is more important that reducing the duration of outages. However, the most important issue is to reduce the number of day-to-day interruptions;
- The majority of customers prefer to maintain levels of investment in line with the proposal filed in Hydro One's last transmission rate application (EB-2016-0160), rather than to increase or decrease investment levels;[2]
- End user participants rate power quality as an "extremely important" outcome;
- Reliability metrics used by Hydro One do not adequately capture events on the network that may actually be associated with power quality;
- Customers would like to have more assistance investigating power quality events;
- Customers would like reduced timelines for connection estimates;
- Customers would like lower connection costs;
- Customers desire improved communication and transparency; and
- Customers believe Hydro One should be easier to do business with.

Hydro One's full spectrum of customer engagement initiatives is leveraged to increase its understanding of customers' needs and preferences; enhance Hydro One's ability to provide the expected level of service; produce outcomes that are valued by customers;

[2] Customer preferences are set out in Attachment 1 of Section 1.3 of the TSP.

and result in an improvement to customers' overall satisfaction with Hydro One's Transmission business.

As part of the multi-step investment planning process described in TSP Section 2.1, planners develop a set of candidate investments that are designed to address the relevant asset needs and risks, and incorporate transmission customers' needs, preferences and feedback to inform the capital expenditure plan.

1.3.6.1 IDENTIFYING TRENDS

Cross functional sessions are held to review all customer engagement results, identify broad trends and specific customer needs and preferences. This review provides a basis to capture customer needs and preferences in the investment planning process and improve alignment between individual candidate investments identified by planners and the outcomes of the customer engagement activities.

1.3.6.2 INVESTMENT ASSESSMENT

Since the last transmission rate application, Hydro One has introduced investment planning process improvements, including a revised scoring process and a formalized flagging framework as described in TSP Section 2.1.4. The feedback provided through the customer engagement process informed the enhanced risk and scoring framework. In particular, the revised scoring process focuses on assessing risk related to safety, reliability and environmental considerations. These three outcomes are among the top customer priorities identified and validated through Hydro One's customer engagement. As risk scoring is the dominant evaluation method for candidate investments, customer needs and preference are reflected in all risk-scored investments.

In addition to investment scoring for safety, reliability and environmental risk, investments are flagged for factors including customer needs and preferences identified through the engagement process. A full list of flags is included in TSP Section 2.1.4.2.

Examples of customer needs and preferences that were identified through customer engagement and flagged include:

- Concerns expressed with delivery point performance as a result of nuisance wildlife or equipment configuration;
- Coordination of asset maintenance and replacement activities with generator customers during planned outages to minimize disruptions to operations;
- Concerns expressed with power quality; and
- Addressing worst performing delivery points (outliers).

1.3.6.3 CALIBRATION SESSIONS

Following the development of investment candidates and risk scoring, structured calibration sessions are held to ensure that scoring and the application of flags is consistently applied across the organization. Based upon business knowledge gathered through customer-facing efforts described earlier and results obtained through the Transmission Customer Engagement Survey, management validates that the investments are responsive to customer needs and preferences by comparing the description of the need/preference with the high level themes identified through the customer engagement results.

1.3.6.4 OVERALL FUNDING ENVELOPE

The feedback received through the customer engagement process influenced the company's decisions around the overall funding envelope. As part of the customer engagement survey, respondents were provided with descriptions of four illustrative investment scenarios. They were then provided with a line of data points that started at zero and extended beyond all four of the illustrative investment scenarios. Customers were asked to select any point along that continuum that reflected what they believed to be the best and most appropriate balance between rates impacts and outcomes:

- Scenario A was based on limited investment;
- Scenario B involved a decrease in the current level of investment;

- Scenario C would maintain the current level of investment; and
- Scenario D would increase beyond the current level of investment.

Scenario C, which maintains the current level of investment proposed in EB-2016-0160, reduces reliability risk, improves long-term reliability performance and offers level future rate increases, was strongly favored over the other three scenarios with 24% of respondents selecting this scenario. Respondents indicated their preference through the selection of a point along a line showing the spectrum of scenarios; 21% chose a point between Scenario B and Scenario C and 17% chose a point between Scenario C and Scenario D. This clustering informed the initial funding envelope.

1.3.6.5 PRIORITIZATION, OPTIMIZATION, ENTERPRISE ENGAGEMENT AND MANAGEMENT REVIEW AND APPROVAL

Following review and calibration, all candidate investments were aggregated into a consolidated portfolio for prioritization with a view to reflecting the level of investment most preferred by customers in the customer engagement exercise. While the initial prioritization and optimization is risk based, subsequent structured and facilitated trade-off discussions identify projects on the margin and determine allocation of funding based on consideration of investment merits from both risk and non-risk perspectives, such as the appropriate incorporation of customer needs and preferences.

Ultimately, Hydro One determines a funding envelope that balances identified transmission customer needs and preferences with rate impacts and asset/system needs. These considerations are integral in the review and final approval of the Business Plan by the Executive Leadership Team and Board of Directors.

The manner in which the proposed capital expenditure plan reflects the aforementioned transmission customer engagement initiatives, including in particular the 2017 Transmission Customer Engagement Survey process, is discussed in TSP Section 3.2.2.

1.3.7 ATTACHMENTS: CUSTOMER ENGAGEMENT

Attachment #1 - Customer Engagement Survey

Attachment #2 - Stakeholder Engagement Session Presentation Slides

Attachment #3 - Stakeholder Session Notes

Attachment #4 - Reliability Risk Summary

Attachment #5 – Large Tx Customer Satisfaction Survey Report

Attachment #6 – OGCC Customer Satisfaction Survey – 2018 Results

APPENDIX 1: CUSTOMER ENGAGEMENT PROCESS AND TIMING

Managers and Executives from Hydro One's Customer Service, Planning and Regulatory groups met in February 2017 to plan and prepare for the 2017 Transmission Customer Engagement Survey process, with a view to using the results of this initiative to guide and inform the investment planning process as part of this Application.

Hydro One determined that all of its transmission-connected customers would be invited to participate in this process and that, given the discrete number of transmission customers (in comparison to the number of customers that need to be engaged with to support preparation of a Distribution System Plan), this effort would be qualitative rather than quantitative (i.e., it would provide guidance directionally, but not statistically, due to the limited population size of the transmission customer base). The survey was also developed based on the engagement sessions with stakeholders from the 2017/2018 application.

The 2017 Transmission Customer Engagement Survey process was implemented based on the following schedule.

Description	Date
Final Survey Submitted	03-May-17
Survey In Field	11-May-17 – 15-Jun-17
Interim Report	31-May-17
Survey Concluded	09-Jun-17
Final Report	02-Jul-17

Findings were used to inform the plan as it was iteratively developed through the planning and feedback process.

Detailed results of the 2017 process are set out in the IRG Customer Engagement Report provided in Attachment 1.

APPENDIX 2: INCORPORATING FEEDBACK INTO THE CUSTOMER ENGAGEMENT SURVEY

Hydro One's approach to engaging transmission customers has evolved, and continues to evolve, in response to the OEB's recommended areas for improvement as set out in its September 28, 2017 Decision and Order in proceeding EB-2016-0160. In particular, the OEB found that Hydro One should (i) begin its customer engagement process sufficiently in advance of filing the application to allow for timely input to be incorporated in a meaningful way and to improve the level of customer attendance; (ii) include LDCs so as to determine practical ways to seek some input from their end users; (iii) incorporate timely and meaningful input from First Nations representatives; (iv) ensure that information presented to customers is unambiguous and easy to understand.[3]

The 2017 Transmission Customer Engagement Survey was designed to be responsive to feedback heard from OEB staff and intervenors in the EB-2016-0160 proceeding and is consistent with the Board's findings in its Decision and Order. Hydro One made a number of improvements that address the Board's findings.

FINDING 1: TIMING OF CUSTOMER ENGAGEMENT SURVEY

The 2017 engagement survey was completed prior to the Investment Planning Context phase of the Investment Planning Process outlined in Section 2.1 of Transmission System Plan.

FINDING 2: INCLUDE FEEDBACK FROM LDC END-USERS

Hydro One's transmission system is the upstream supplier of electricity to LDCs across the Province of Ontario. Electricity is transmitted over the Hydro One transmission system to Delivery Points ("DPs") with the LDCs. DPs are boundaries between the electricity systems of Hydro One and the LDCs. Each LDC has significant power

[3] See OEB, Decision and Order in EB-2016-0160, September 28, 2017, pp. 24 and 117.

requirements, unique needs, a diverse group of end-use customers, and most importantly, distribution systems designed to meet their requirements and needs, to service their end-use customers. There is no direct link between the Hydro One transmission system and the LDC's end-use customers.

In Hydro One's 2017 Transmission Customer Engagement Survey, Hydro One asked LDCs to identify whether their responses to the survey were informed by their own customer engagement activities for the purposes of their own rate applications, or by any other customer research. Of the 28 respondents, 11 answered "yes" to this question. Additionally, Hydro One's Account Executives interact with the LDCs, and engage the LDCs in discussion regarding the needs of their ultimate end-use customers, as described above. Results from these inputs were considered by Hydro One during its investment planning process. In addition, Hydro One noted that in customer surveys conducted by other LDCs, residential customers, small business customers (general service<50 kW), and mid-market customers (general service>50 kW) consider price their number one priority and reliability their number two priority whereas larger demand key accounts prioritize reliability over price. These results demonstrate the importance of keeping costs as low as possible while maintaining system integrity to ensure reliable service to businesses in the province.

Subsequent to the issuance of the OEB's decision, Hydro One contacted some LDCs to solicit further approaches it could use to solicit feedback from LDC end-users, in the future. The feedback from LDCs included: (i) suggestions to continue using the account executive model to serve the needs of LDC customers, a program Hydro One has expanded as described above; (ii) that Hydro One meet with the large industrial customers of other LDCs, with Hydro One executives responding to customer concerns. Hydro One executed this suggestion and will facilitate future meetings as requested by LDCs; and (iii) that Hydro One may review LDC survey information. As indicated above, Hydro One considered the results of other LDCs customer surveys during its investment planning process.

FINDING 3: INCORPORATE INPUT FROM FIRST NATION REPRESENTATIVES

As noted, one message that Hydro One heard in the last transmission rate proceeding was that First Nations customers were not effectively represented in Hydro One's transmission customer engagement process, nor was any particular process in place to specifically engage with these customers. To respond to this concern, Hydro One asked LDC customers who serve First Nations communities whether there was anything in particular they felt Hydro One could do to better serve the specific needs of First Nations and Métis communities. Hydro One also leveraged its ongoing engagement activities with First Nations and Metis communities to identify customer needs and preferences for these customers. Details of Hydro One's ongoing initiatives can be found in Exhibit A, Tab 7, Schedule 2.

FINDING 4: ENSURE INFORMATION PRESENTED TO CUSTOMERS IS EASY TO UNDERSTAND

Finally, the design of the 2017 engagement survey included information that was purposefully written to ensure the content was unambiguous, sufficiently informative for customers to respond to, and easy for customers to understand. To gauge the quality and clarity of the information, the survey included a post-survey question asking "Did Hydro One provide too much information, not enough or just the right amount?" The result was that 76% of respondents believed the survey contained just the right amount of information.

Stakeholder Session

A stakeholder session, which included OEB staff and interveners who participated in prior Hydro One transmission rate proceedings, was held on March 22, 2017. The session aimed at gathering thoughts and insights from stakeholders on Hydro One's prior customer engagement activities. The feedback provided during this session was addressed as part of the 2017 Transmission Customer Engagement Survey process, as summarized in Table 1 below.

Table 1 - Summary of Feedback Received by OEB Staff and Interveners and Hydro One's Actions Taken

Feedback Received	Action Taken
Consultation did not take place early enough to have impacted business decisions.	The 2017 Transmission Customer Engagement report was released to Hydro One planners in 2017 and was incorporated into the iterative planning process undertaking in 2018.
Participation rates were low in the 2016 Transmission Customer Engagement effort, and did not represent the ones who will feel the impact of an increase (i.e., end-users of LDCs).	Hydro One invited all transmission customers to participate in the survey via a variety of channels. For the 2017 survey, 103 of 153 customers, or 66% of Hydro One transmission-connected customers, participated in the survey including a large number of LDCs.
A subset of the majority of attendees does not pay transmission rates directly and, therefore, Hydro One addressed the wrong audience.	A section for LDCs was added to the survey to address this concern, asking for the LDC's feedback to be provided on behalf of their customer base.
The costs of improved reliability and top quartile status were not fully explained to participants, impacting customer perception and whether they were willing to approve increased spending approvals.	A broader spectrum of options and enhanced details about each option were provided as part of investment outcomes.
There was a perceived endorsement of the middle investment scenario option and survey participants did not have enough options with 3 scenarios presented.	Customers were provided 4 detailed scenarios (as referenced in Attachment 1) and, when indicating their preference, were not constrained to choose one of the four scenarios, but rather respondents were asked to choose a point on a continuum (a total of 17 possible responses).
There was a perception that risks were exaggerated impacting customer perception to approve increased spending	IRG was asked to correct any wording used as part of the survey that could be perceived as 'leading' and additional information was provided in supplementary

Feedback Received	Action Taken
approvals, and that the risk model was not mature or predictive.	materials to better explain how and when the Hydro One Reliability Risk Model[4] is used. A broader spectrum of outcomes beyond reliability risk was provided to customers for each investment scenario to allow for more informed selections.
First Nations Customers were not represented and no consultation process was in place.	Hydro One engages with First Nation customers on a regular basis through a variety of channels (as outlined in Exhibit A, Tab 7, Schedule 2). Although Hydro One has no First Nation transmission customers, LDCs who serve First Nations and Métis Nation customers were asked specifically to provide feedback on how Hydro One could improve service to these customer segments. Of the LDC customers served by Hydro One who self-identified as serving First Nations and Métis communities, two provided a response. One indicated that Hydro One did not need to do anything else. The other stated that, "The northern single circuit communities deserve more attention as they are more vulnerable in terms of supply and outage response." This feedback was considered when assessing the overall pool of investments addressing lower performing sections of the transmission system. Hydro One actively monitors all customer delivery point performance and invests in the system to address customer power quality concerns. Significant investment is planned in wood pole replacements, where the majority of the asset population is located in northern Ontario, along with transmission line refurbishments to address poor condition assets that pose a high risk to customer reliability.
Customers may not have fully understood what was being asked of them.	Links were included in the survey that took customers to a second document with more contextual information and definitions of terms used in support of the survey.
Confusing terms were used by Hydro One as part of the survey with terms used interchangeably, confusing customers (outage, interruption, end of useful life, expected service life, etc.).	The survey was carefully developed to be consistent with the use of terms throughout the survey process. Clarity on terms was provided in the supporting materials described above.

[4] Further details regarding the reliability risk model are provided in Attachment 4.

An additional discussion on end-user customers is presented in TSP Section 1.5.2, *Responses to OEB Directions from EB-2016-0160, LCD End-User Satisfaction.*

The presentation slides and summary notes from this stakeholder session are provided as Attachments 2 and 3 to this section of the TSP.

INNOVATIVE
RESEARCH GROUP

Hydro One

Transmission Customer Engagement

JULY 2017 | REPORT

STRICTLY PRIVILEGED AND CONFIDENTIAL

Table of Contents

Survey Methodology

Overview:
Innovative Research Group (INNOVATIVE) was commissioned by Hydro One to conduct a customer engagement survey with its 156 transmission customers. INNOVATIVE worked closely with Hydro One to ensure that the survey structure and all questions were methodologically sound and that all data was collected in a private and secure manner. The results of the survey will be used as input for Hydro One's 2019 to 2023 business plan.

Sample Frame:
Hydro One and INNOVATIVE made efforts to contact all 156 Hydro One transmission customers to participate in this engagement (see details below). From a list of 156 customers, a total of 103 completed the survey.

Methodology:
In order to meet the needs of senior executives, customers were given the option of participating online on a custom site created and hosted by INNOVATIVE, or through an in-person or telephone interview with a senior INNOVATIVE consultant. While most customers chose to use the online tools, one customer requested an in-person interview and three opted for a telephone interview.

The survey design kept the amount of background information to a minimum in recognition of the high level of electricity system knowledge of many participants. To assist customers who are less engaged in the system, additional information (see Appendix 1.3) was made available to all survey participants, either with "click to access" buttons throughout the online survey, or in a standalone document for those who completed an in-person or telephone interview.

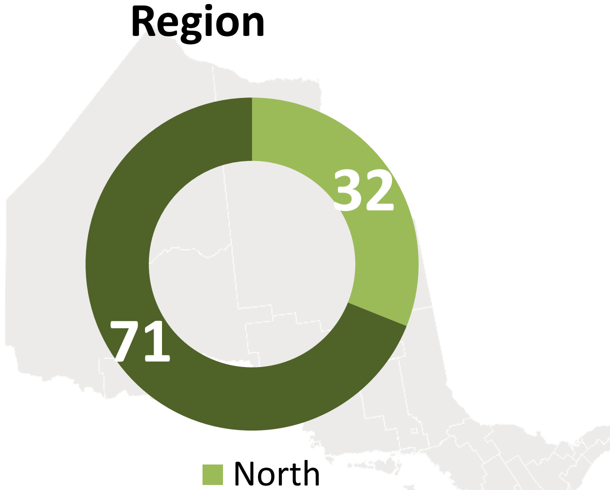
Where possible, invitations were initially extended through a phone call from Hydro One account executives and INNOVATIVE researchers. Most (n=142) customers were successfully contacted by phone and all but nine of this group (who stated they were not interested) were subsequently sent an email from INNOVATIVE which contained an individual URL for the survey site. Twelve customers who were not reached by phone were sent an email invitation which included a direct link to the online survey, along with contact details for an INNOVATIVE consultant should they wish to do an in-person or telephone interview. There were only two customers who could not be reached by email or by telephone.

Field Dates:
May 11th to June 15th, 2017

Participant Segmentation

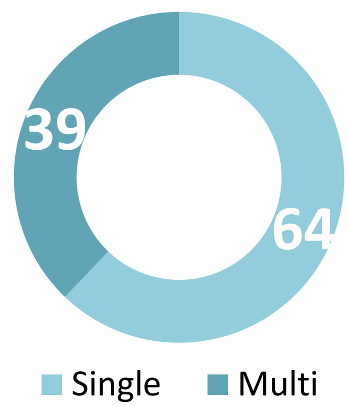
Hydro One understands that its customers have differing needs and preferences. To understand these differences, Hydro One asked that the results be presented in certain segments, as described below.

Region



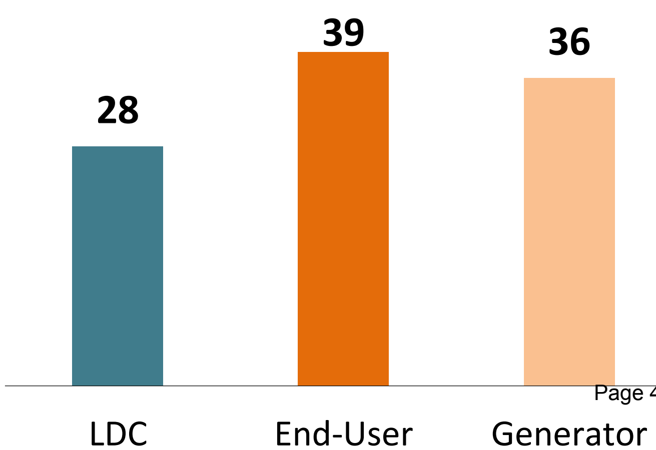
Northern customers commonly use a large percentage of the power delivered by their respective lines. Lines in the North tend also to be relatively long in length. Southern customers are generally more tightly integrated into a larger grid and more frequently share lines with many other transmission customers.

Single/Multi Circuit



Multi-circuit customers have relatively low frequency of outages given the inherent redundancy. Single circuit customer do not benefit from redundancy and have a much higher risk of outage when an interruption in the system occurs.

Business Segment



Local Distribution Companies (LDCs) take power and distribute it to other customers within their franchise area. End Users take power directly and use the power for their own purposes. Generators deliver power to the transmission system, often in very large quantities.

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Executive Summary (1)

Response to the Customer Engagement

Of Hydro One’s 156 transmission customers, a total of 103 participated in this customer engagement – a response rate of 66%. Every customer who started the survey reached the end of the survey, where they were asked to provide feedback on the engagement itself. Participant response was overall positive and most felt that “just the right amount” of information was provided for the engagement.

Current Performance

In preparation for an open-ended probe designed to address their overall needs, customers were asked how satisfied they are with Hydro One’s overall performance. As in other research, most transmission customers are satisfied in this regard.

In response to an open-ended question to identify any needs that Hydro One may not be meeting, many customers did not provide any suggestions. However, those who did suggested Hydro One could improve in the areas of customer service, reliability and infrastructure. All suggested areas for improvement are included in Appendix 1.1.

Customer Outcomes

Hydro One and INNOVATIVE reviewed previously available documents and talked to customer-facing Hydro One staff in order to develop a list of customer outcomes that was included in the survey. Prior to being exposed to this list, an open-ended question designed to elicit outcomes in customers’ own words was asked. In response to this open-ended question, transmission customers said they know Hydro One is doing a good job for their business based on reliability, and customer service/communication (both of which were included in the list of outcomes developed for the survey). All outcomes suggested by transmission customers are included in Appendix 1.1.

Rating the provided list of seven customer outcomes on a scale of importance from 0 to 10 revealed that safety and reliability are top outcomes in terms of importance. When ranking in terms of what should be Hydro One’s first priority, safety and reliability once again appear at the top of the list. However, through the lens of a combined ranking (first, second, and third), reliability becomes the top priority followed by safety and outage restoration.

Pace of Investment

All business segments, particularly LDCs, prefer that investments be spread out over time, along with stable rate increases. This preference is due primarily to perceived affordability for ratepayers and the ability to plan ahead.

Executive Summary (2)

Reliability

In their own words, transmission customers define reliability using phrases like “lack of outages”, “stable power supply”, and “quality of power”. They also note that outages are not only a safety hazard, but also a financial concern affecting their business/production.

Reducing the frequency of power interruptions is more important than reducing the duration. Most important is reducing the number of day-to-day interruptions.

Illustrative Investment Scenarios

By a wide margin, maintaining the current level of investment (Scenario C) is the most popular choice over the other three scenarios. It is seen as reflective of the current approach which has the advantage of familiarity, and a less risky option. Second choice falls somewhere in between a decrease in investment (Scenario B) and maintaining the current level.

Differences Across Business Segments

Local Distribution Company (LDC) participants are less likely than End Users or Generators to consider reliability “extremely important”. Environmental stewardship is also less important among LDC customers than it is among the other Business Segments. On pace of investment, LDC customers show the strongest preference for spread-out investments and stable increases. Seventeen of 28 LDC customers prefer illustrative investment Scenario C (n=6) or an option one (n=6) or two (n=5) points lower along the spectrum (towards Scenario B).

About half of **End User** participants (19 of 38) rate power quality an “extremely important” outcome – a higher proportion than either LDC or Generator customers. End Users also consider productivity more important than the other business segments. While most (n=11) End Users selected illustrative investment Scenario C, they are also more likely than other business segments to have selected Scenario B (n=5).

Generator participants are most likely to consider safety an important outcome, with 30 of 35 rating it “extremely important”. This business segment also considers customer service to be more important than the other two business segments with about half rating it “extremely important”. Only among Generators does the level of support for illustrative investment Scenario D (n=6) approach the level of support for Scenario C (n=8).

Current Performance

Current Performance: Summary

Most transmission customers are satisfied with the overall performance of Hydro One in providing their business with electricity, suggesting that customer expectations are being met. That being said there are some End Users who report being “very dissatisfied” with Hydro One’s provision of electricity.

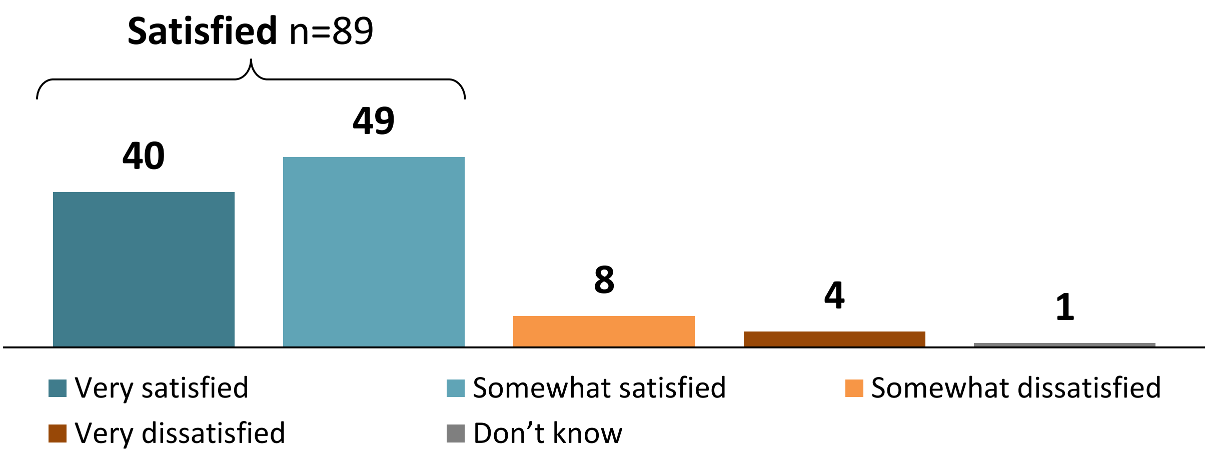
In response to an open-ended question, customers cite reliability and infrastructure concerns most frequently as outstanding needs. Reliability is mentioned most frequently by Generators and customers in the North. LDC customers are more likely than other business segments to mention infrastructure. Customers in the North and End Users do not mention improved communication in terms of outages, but LDCs and Generators in the rest of the province do. LDCs and those served by a Multi-Circuit connection are more likely than other segments to be looking for improved communication in general.

Overall Performance:

Across the board, most are satisfied with Hydro One's performance in providing their business with electricity

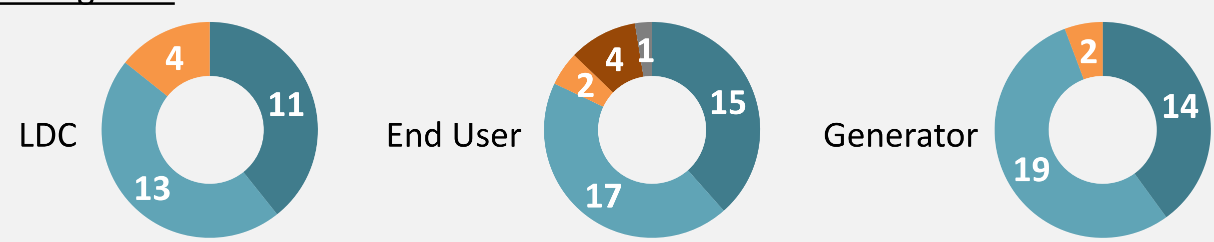
Q **How satisfied are you with the overall performance of Hydro One in providing your business with electricity?**

[asked of all respondents, n=103]

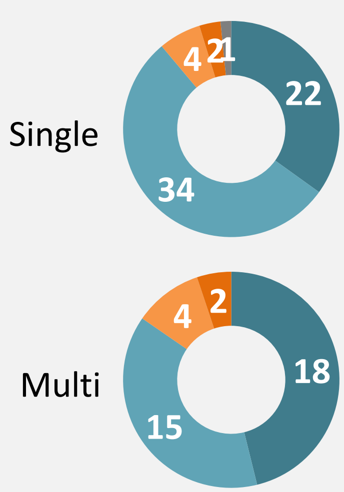


NOTE: No response (n=1) not shown

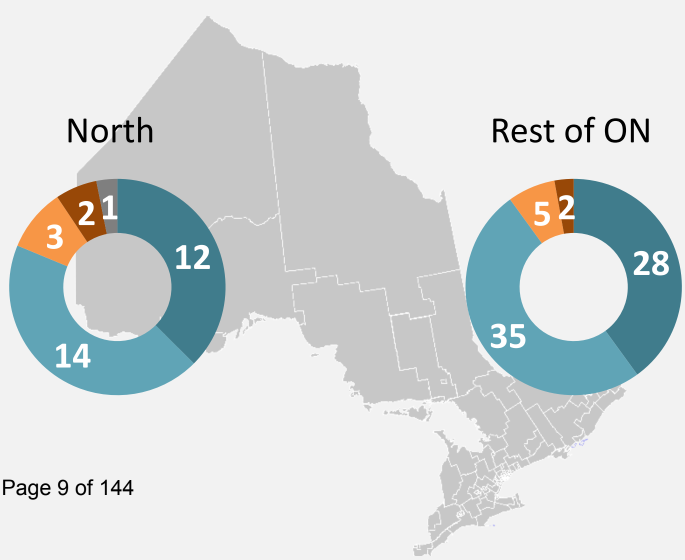
Business Segment



Single vs. Multi Circuit



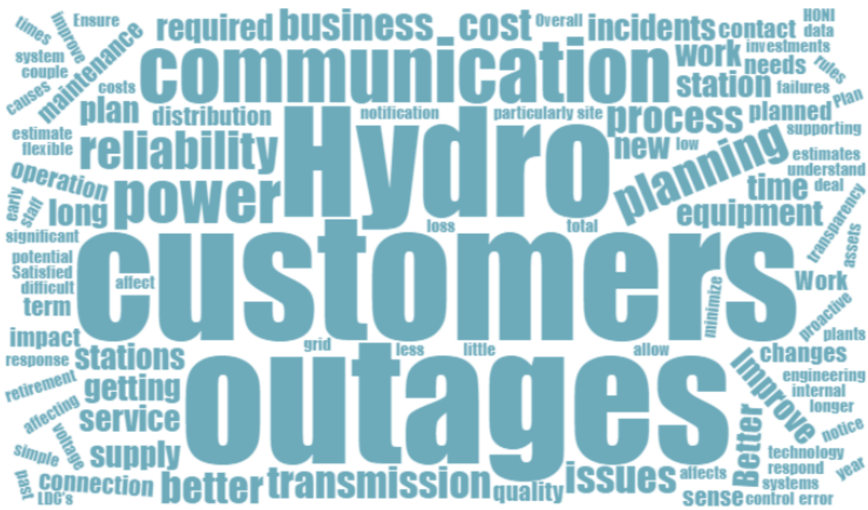
Region

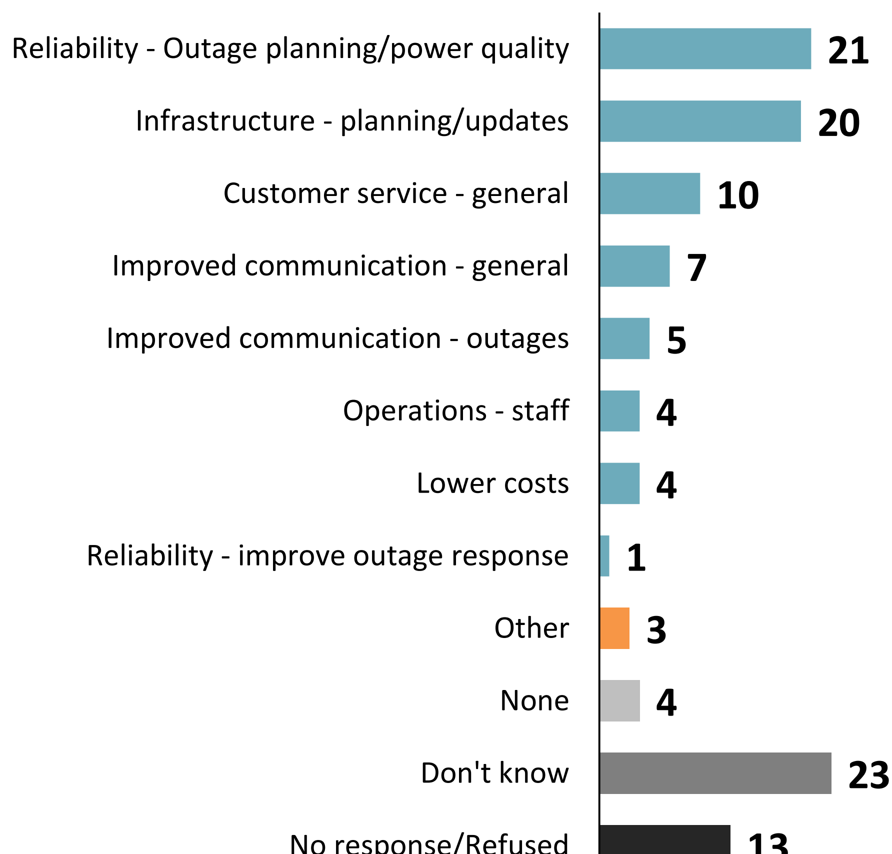


Suggestions for Improvement:

Reliability and *infrastructure* are top mentions

Is there anything in particular you feel Hydro One can do better?
[asked of all respondents, n=103]





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NOTE: Total is greater than 103 due to responses being coded into multiple categories

Suggestions for Improvement:
Verbatim for the top two responses

Reliability – Outage planning/power quality

- Address "power quality"
- be more reliable
- Better coordination of outages and associated changes to same which might affect generating stations on the same network.
- Coordinate planned maintenance outages - proper lengthy notice
- Decrease the number of outages
- More assistance with power quality investigations, especially where HONI customers are affecting our customers (i.e. HONI arc furnace customers causing voltage flicker issues for our customers)
- Plan HO outages during our low production times to limit the loss of revenue to our business
- Plan outages better and work in better with clients to minimize impact on their business
- Timely contact with Account Rep to review transmission system reliability and incidents affecting WNH
- Understanding the true meaning of reliability and the impacts this has not only on HO customers but the impacts this has on its neighbours.

Infrastructure – planning/updates

- Add capacitance on S2B line?
- Continue to maintain the distribution equipment.
- Earlier engagement with impacted LDC's for station asset renewal projects.
- Ensure reliability of supply by ensuring equipment supporting our plants is maintained to highest standard. Ensure management and training of staff supports safe and error free operation of equipment supporting our plants particularly the nuclear fleet.
- Estimation, planning and engineering could be more proactive with generators. A lot of delay in getting cost estimate and work planning are having huge impact on our business.
- I would like to see the long term plan for Hydro One transmission investments to see how it fits with our business requirements. I feel Transmission Station investments should be pooled to avoid duplication
- Improve Hydro One's procurement process to minimize delays in resolving equipment issues.
- Interaction between technical/engineering groups and customers early in the connection process needs to improve. Improved sense of accountability required at Hydro One. Actual connection costs coming in well outside acceptable industry variance ranges. Paying significant amounts for connection estimates that provide little value (+/-50% estimate is unacceptable from any engineering firm). No sense of urgency, unless the lights are out.
- Line Maintenance needs improvement due to two recent Sky wire failures.
- our response is transmission based only and does not include distribution supplied locations. Better notification and planning with regards to maintenance activities would allow us to better plan and respond to our down stream customers.
- Overall satisfied, however, some H1 assets are getting aged and maintenance times to return transformers back to service appear to be getting longer. Potential for future issues.
- Share long term plan and how it affects my site
- there have been some concerns expressed over voltage regulation and insulators failures at the ts.
- Timeliness of transmission station upgrades and renewal.
- Upgrade facilities to allow for simple transfer to alternate circuit in the event of work required on our circuit.

See Appendix 1.1 for all verbatim responses

Customer Outcomes

Customer Outcomes:
Developing the List of Outcomes

The Hydro One transmission customer engagement survey presented customers with a list of seven customer outcomes, which they were then asked to rate in terms of importance, and rank in terms of priority.

To develop this list of outcomes, we first conducted a review of existing research and other documentation, which included a study conducted by INNOVATIVE for the Canadian Electricity Association (Hydro One was a subscribing member for this research), Hydro One's strategic planning documents, a Transmission Customer Satisfaction Report written by Northstar in February of 2017, and a Transmission Customer Consultation Report prepared by Ipsos in April of 2016.

In addition to these materials, Hydro One senior representatives walked INNOVATIVE consultants through their internal planning process in order to explore how investment areas correspond to customer outcomes.

In order to ensure customer input was included in the development of the list of customer outcomes for the survey, a Hydro One senior executive conducted one-on-one interviews with customer-facing Hydro One staff. A summary of these interviews was shared with INNOVATIVE during the survey development phase.

Customer Outcomes: Summary

At the start of the survey, respondents were asked an open-ended question designed to elicit customer outcomes. Reliability - reduction of interruptions and good communication top the list of mentions. Looking at respondent segments, there are few differences, however, LDCs and those in the North are more likely to mention customer service in terms of availability than other customer segments.

Respondents were asked to rate seven customer outcomes on a scale of 0 (not at all important) to 10 (extremely important), and then to rank them in order of priority. The first exercise gives an idea of perceived importance of each individual outcome, while the ranking shows how customers perceive the outcomes in relation to each other. When asked to rate the *importance* of an outcome, safety and reliability receive the highest ratings. When asked to rank in order of *priority*, two stories emerge. Through the lens of first priority ranking, safety and reliability come out on top. When looking at the first, second, and third rank combined, a slightly different story appears. Reliability is ranked highest, followed by safety, and outage restoration becomes the third highest ranked outcome. Power quality and customer service land in the middle, and productivity and environmental stewardship are the bottom two.

At the overall level, 79 out of 103 survey participants rate safety “extremely important”. In fact, across all customer segments, most consider safety to be “extremely important”. Among Generators, there is not a single respondent who rates safety lower than a nine.

Reliability is second only to safety, with 71 of 103 rating it “extremely important”. Looking at the various customer segments, while there are some who rate reliability as low as a six, at least half consider reliability to be “extremely important”.

With 60 of 103 rating it “extremely important”, outage restoration rounds out the top three customer outcomes. In the North, no one rated outage restoration any lower than an eight, but in the rest of the province, a handful rated it seven or lower.

Fewer than half (44 of 103) rate power quality as “extremely important”. LDC customers do not give power quality a rating lower than a six, but there are customers in all other segments who consider power quality to rate somewhere between a zero and five on importance.

Looking at the bottom three, customer service is considered “extremely important” by 41 out of 103. Proportionately, Generators and transmission customers in the North are most likely to rate customer service a 10.

About a third (37 of 103) rate productivity at a 10. Generators do not rate productivity any lower than a six, but there is at least one customer in all other segments who rates it somewhere between a zero and five.

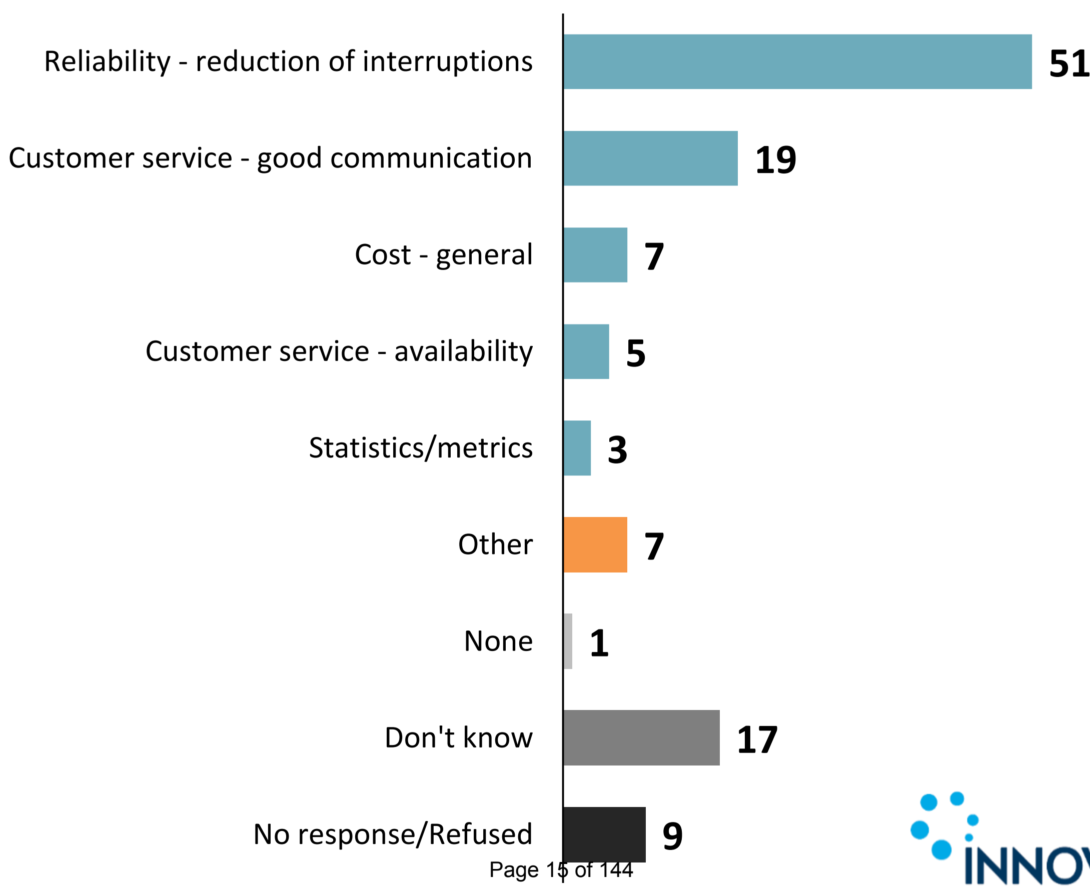
Rounding out the bottom three with 31 of 103 rating it “extremely important” is environmental stewardship. LDC customers tend to rate this outcome lower then End Users or Generators. Customers with a single-circuit connection consider it more important that those with a multi-circuit connection.

Asked if any customer outcomes were missing from the list of seven included in the survey, some customers were able to suggest additional customer outcomes, using phrases like “system capacity”, “value for money”, “response” and “customer service”. None of the suggested outcomes were ranked as being more of a priority than the original seven.

Performance Criteria:

Reduction in outages and interruptions, power supply, and customer service in terms of communication are top mentions for performance metrics

Q **How do you know if Hydro One is doing a good job for your business?**
[asked of all respondents, n=103]



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NOTE: Total is greater than 103 due to responses being coded into multiple categories

Performance Criteria:
Verbatim for the top response

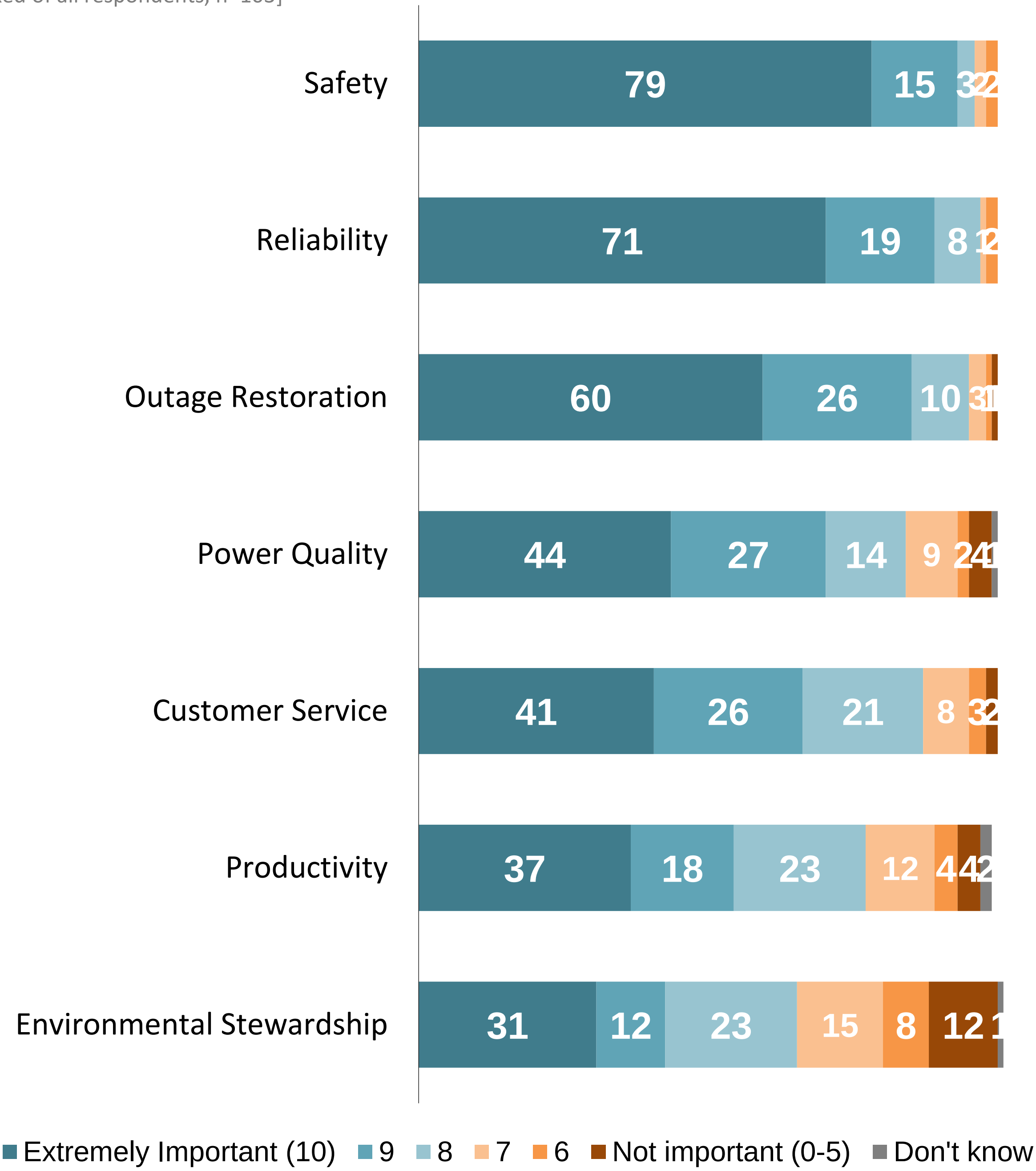
Reliability – reduction of interruptions

- if I do not have to call them
- Keeping the supply of power on
- My power is still on
- No surprises
- On rates, no idea...on work around transmission doing fine, meeting with us generators every 6 months to try and best facilitate outages/repairs/upgrades
- Performance is based on Hydro One's ability to provide its service reliably and implications to our operations.
- Power Supply reliability
- provides reliable supply and responsive service
- Reliability is important but at a cost that makes us uncompetitive and sends jobs abroad is not sustainable and will hurt all citizens of Ontario
- Reliability of supply.
- Reliable electrical power supply.
- reliable supply of electricity at a reasonable cost
- stable grid system, less impact on the customer side are all we need.
- that the delivery of Hydro is reliable
- They work with us in outage management
- Timely and accurate billing and reconciliation. Reliable power.
- We look at overall reliability as well as Hydro One's understanding and explanations of the incidents that have occurred.
- We measure reliability based on Loss of Supply. Quality and timeliness of responses from Distributed Generation and Engineering groups.
- When100% availability is achieved
- 1) No unplanned outages and consistent power quality. Score 8 out of 10. 2) Supportive in planning and outage response. Score 9 out of 10.
- By the way that Hydro One coordinates planned equipment outages with the customer needs.
- Effectively communicating and ensuring to work with customers to minimize impact of business interruption
- Electrical outages are rare and when there is an outage they are quick to respond and communicate the outage
- Few outages, either planned or unplanned
- Fewer outages
- Forced outages are reduced and power quality is improved.
- If the lines remain open for business and interruptions are held to a minimum
- If they are doing good then we won't have any surprise outages and/or time we can't inject into the grid.
- in simple terms as long as the electricity runs through the lines and there are no disturbances causing issues or damage to our equipment then everything is good
- Interruptions are at an absolute minimum and wherever possible with as much advance notice as possible.
- No interruptions in supply and no voltage issues.
- no issues with unplanned outages, invoices are accurate
- Number of outages my business experiences or individual equipment trips due to voltage sag
- Number of power interruptions that occur.
- Power reliability and quality issues reduce to once per year.
- Reliability and costs are the primary drivers in the measurement of performance.
- Reliability to date has been good, however, increasing frequency/duration of reduced redundancy due to extended maintenance periods. Resulting in higher potential risk exposure for customers.
- Reliability, costs, general customer service, responsiveness, operations service and interfaces, ease of doing business with, relationships. Enable the LDC to forward their objectives.
- Reliability, responsiveness
- Reliable service.
- Sustained, reliable electricity delivered to our door. Our joint work - when the actuals are more in line with the plan, be it outages or length of outages, and cost.
- Unplanned outages are minimal, good communication on maintenance being completed
- We are provided with the reliability information from our Network Management Officer.
- We can gage the performance of the HONI system via the number of outages due to loss of supply
- We seldom loose production because of hydro outages
- When I don't hear about any business interruptions or scheduling conflicts.

See Appendix 1.1 for all verbatim responses

Customer Outcomes:
Safety, reliability, and outage restoration are ranked as most important

Q How important an outcome is…
[asked of all respondents, n=103]



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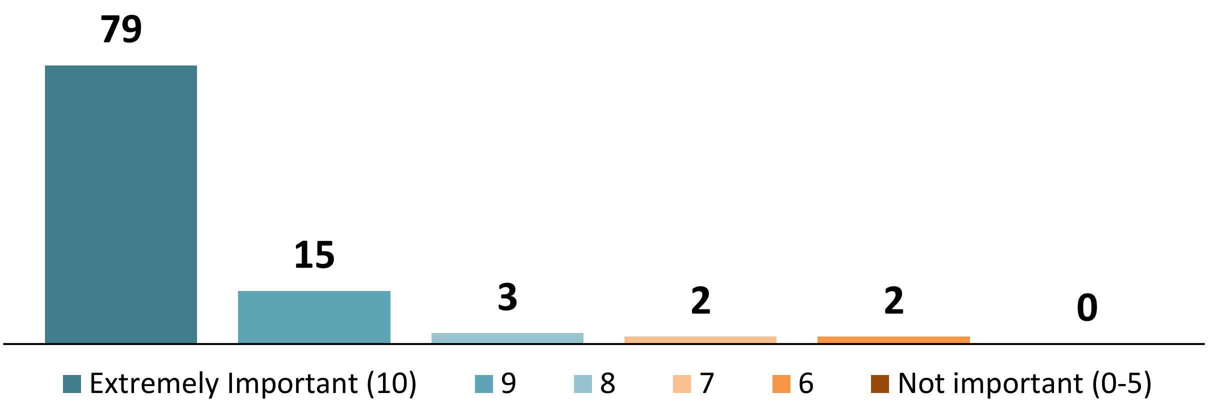
NOTE: No response (n-size varies from 1 to 3) not shown

Safety:
Across all segments, most (n=79) consider safety to be extremely important

Q Eliminating and mitigating risk to public and employee safety in the operation of the transmission system. **How important an outcome is safety?**
[asked of all respondents, n=103]



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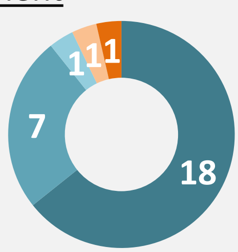
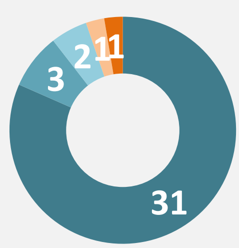
Business Segment

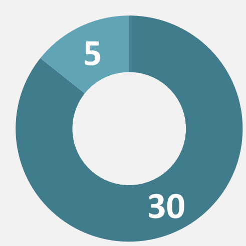
LDC



End User

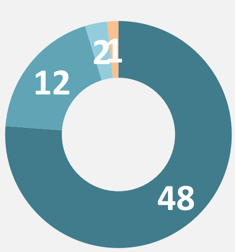


Generator

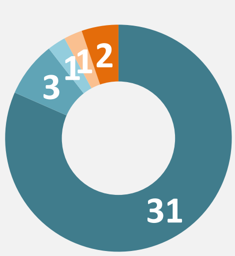


Single vs. Multi Circuit

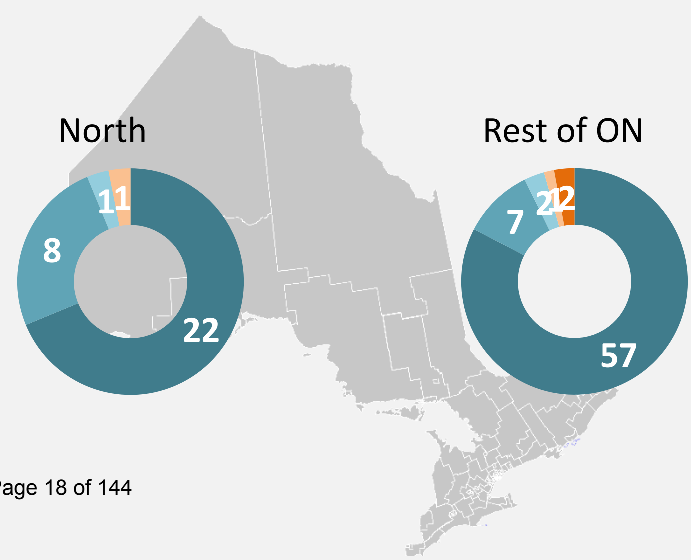
Single



Multi



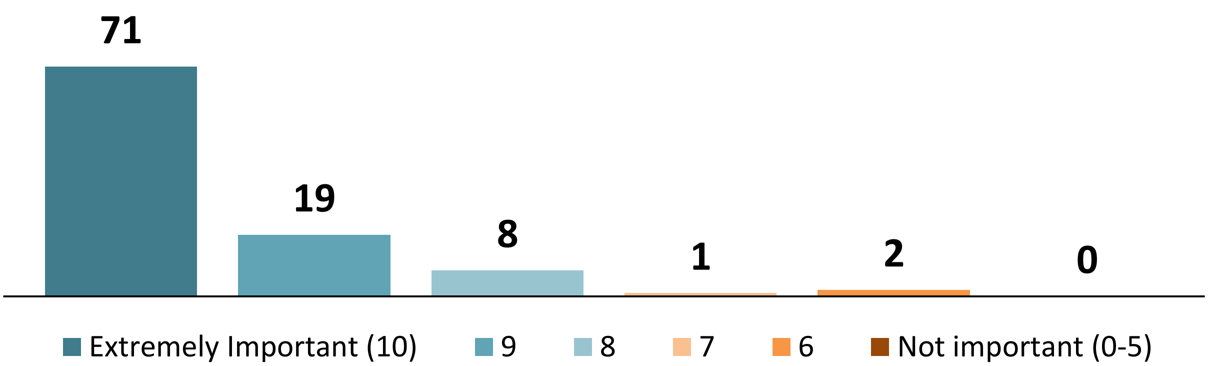
Region



Reliability:

Most (n=71) consider reliability to be extremely important; LDCs are less likely than other business segment cohorts to consider reliability extremely important

Q Maintaining the uninterrupted operation of the transmission system for all customers by sustaining the existing assets, replacing assets that are in poor condition and addressing transmission system performance outliers. **How important an outcome is reliability?**
[asked of all respondents, n=103]



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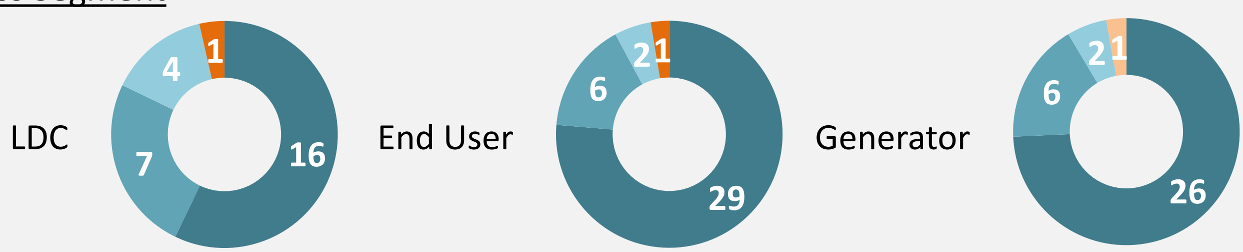
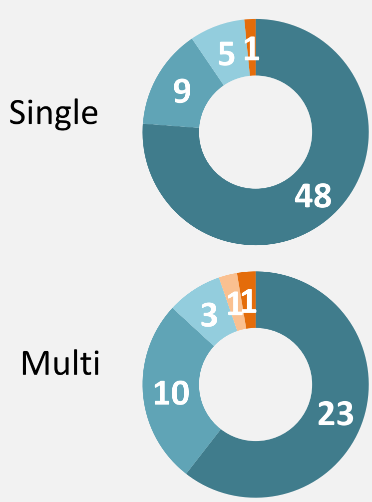
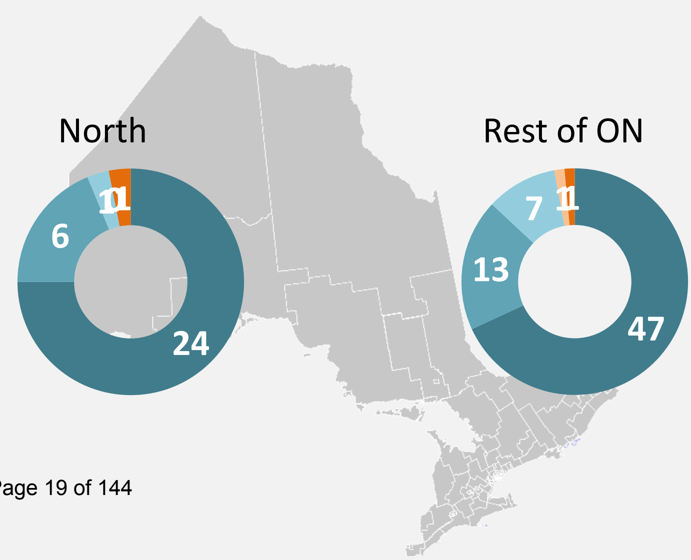
Business Segment



Single vs. Multi Circuit

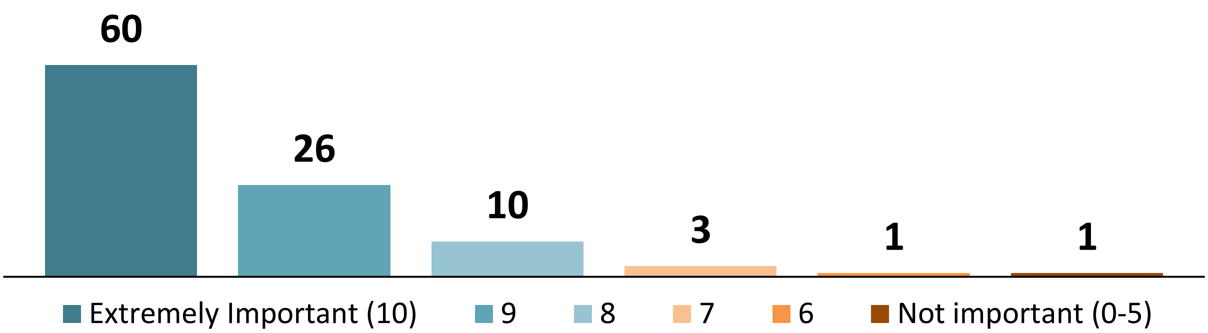


Region



Outage Restoration:
Most (n=60) consider outage restoration extremely important; this opinion is strongest among Single Circuit transmission customers

Q Provisions to ensure timely and efficient response to failures, unplanned outages, or imminent risks to the transmission system to minimize customer interruption and prompt restoration to normal operating conditions. **How important an outcome is outage restoration?**
[asked of all respondents, n=103]



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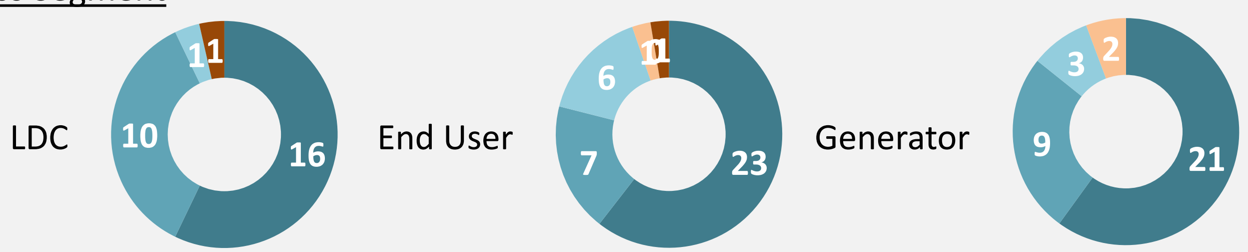
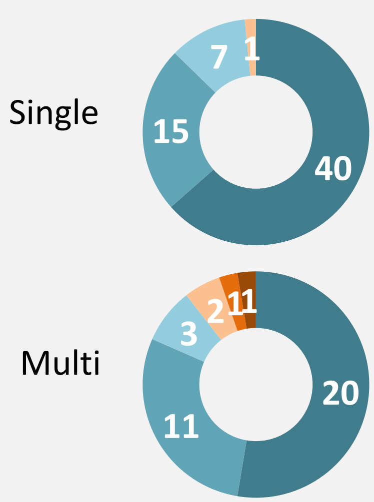
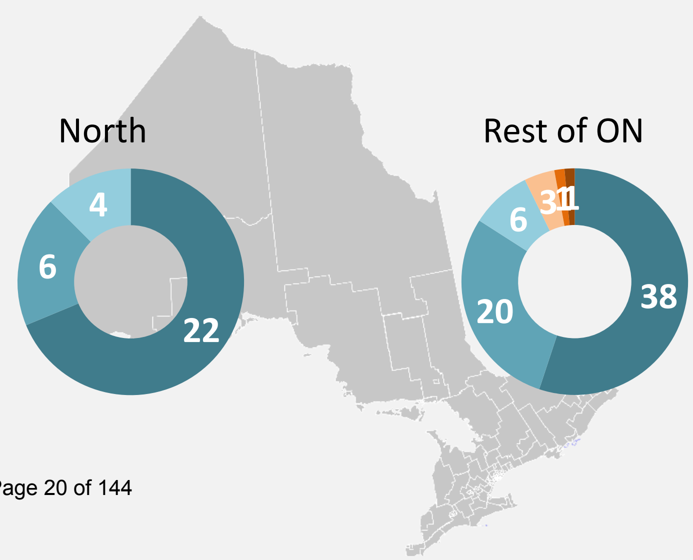
Business Segment



Single vs. Multi Circuit



Region

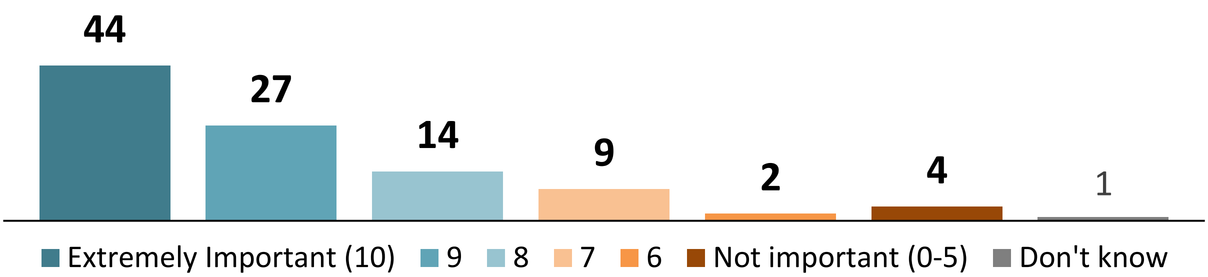


Power Quality:

A plurality perceive power quality as extremely important; this opinion is strongest among Single Circuit and End-User customers

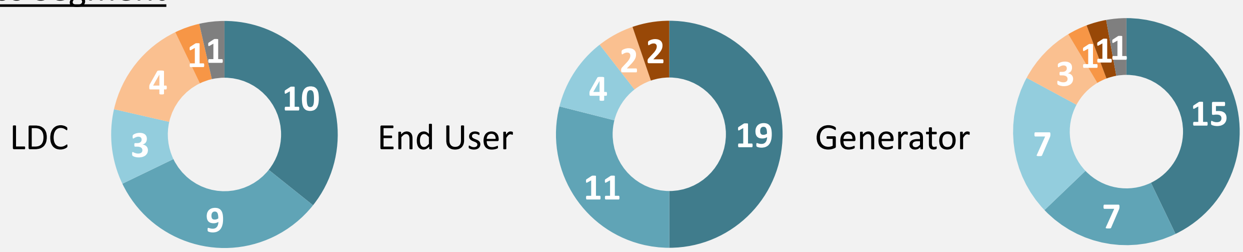
Q Delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform. Assessing customer concerns and implementing mitigation plans to address and rectify power quality issues for transmission connected customers. **How important an outcome is power quality?**

[asked of all respondents, n=103]

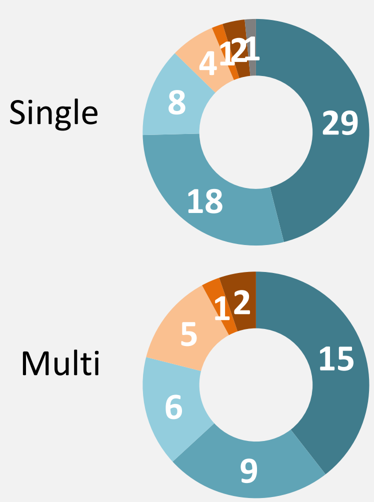


NOTE: No response (n=2) not shown

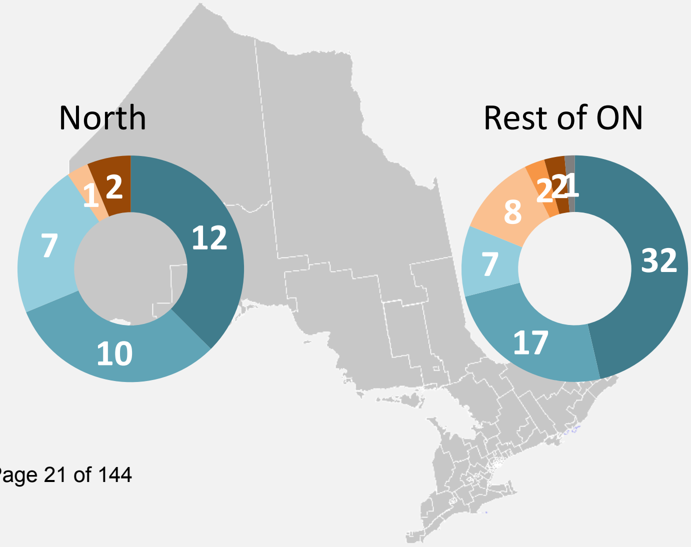
Business Segment



Single vs. Multi Circuit

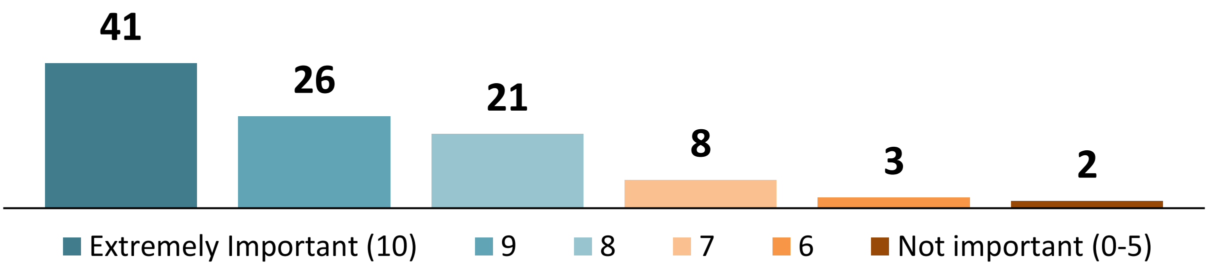


Region



Customer Service:
A plurality (n=41) perceive customer service to be extremely important; this outcome is more likely to be of higher importance to those in the North region

Q Enhancements to the transmission customer experience such as outage planning and operational communications, timely estimates and project execution for transmission connected customers. **How important an outcome is customer service?**
[asked of all respondents, n=103]



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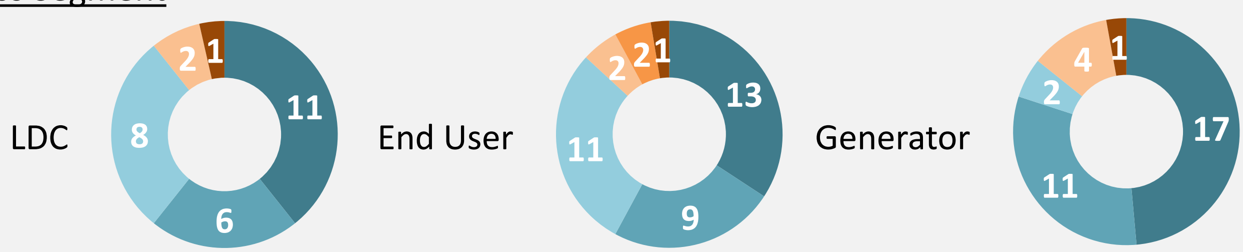
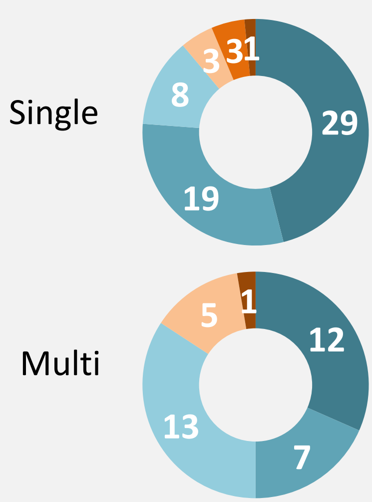
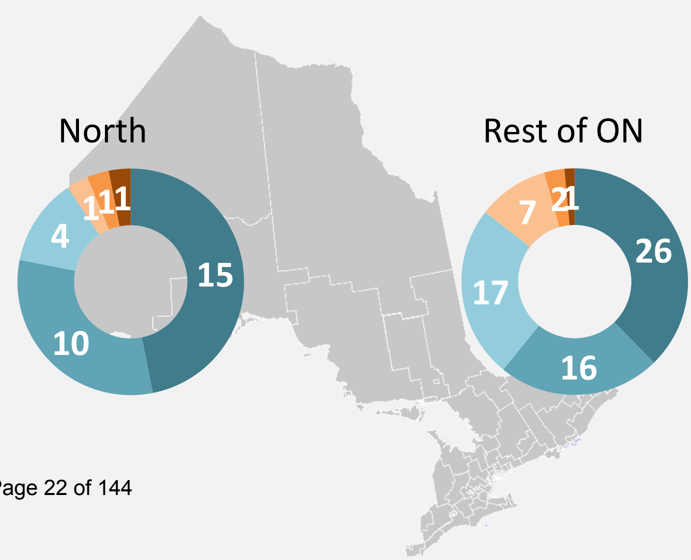
Business Segment



Single vs. Multi Circuit

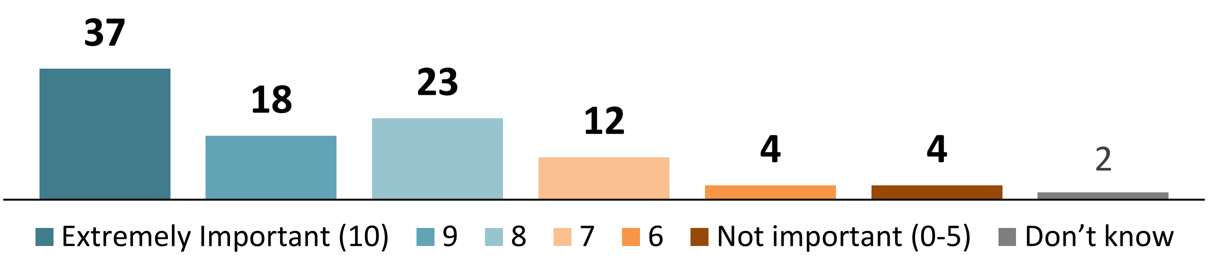


Region



Productivity:
About half of End-Users say productivity is extremely important; importance of productivity is higher for the Single Circuit segment than Multi Circuit

Q Implementation of new technologies and processes to enable operational efficiencies in the planning and execution of work programs aimed at reducing costs and more efficient use of resources. Hydro One understands that customers expect it to look first for internal savings before asking for any additional rates. **How important an outcome is productivity?**
[asked of all respondents, n=103]



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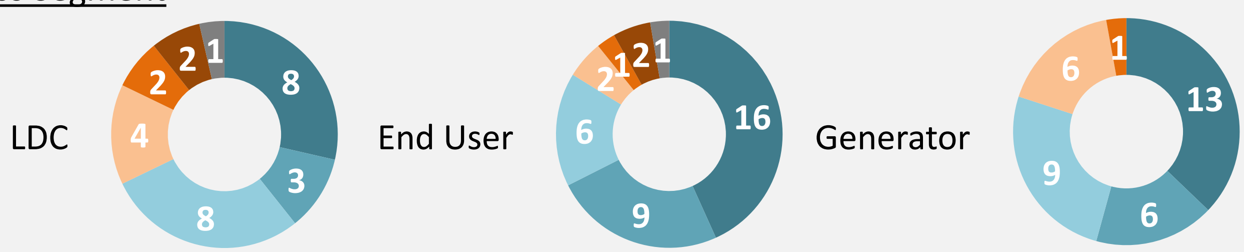
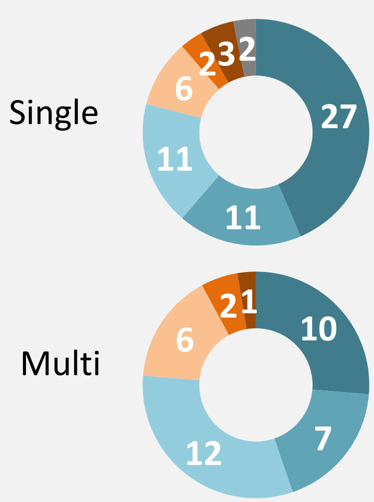
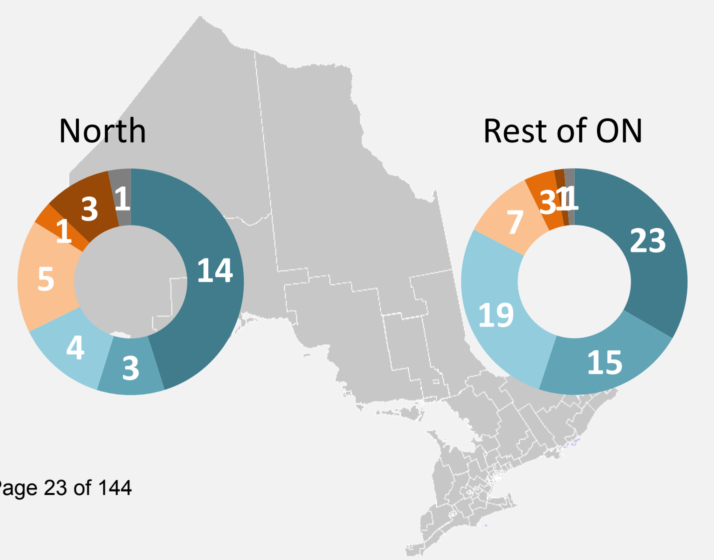
Business Segment



Single vs. Multi Circuit



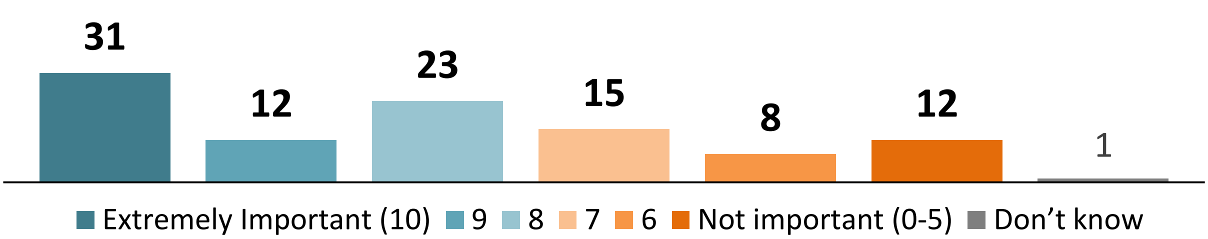
Region



Environmental Stewardship:

Importance of environmental stewardship is highest among the Single Circuit segment; least important among LDCs

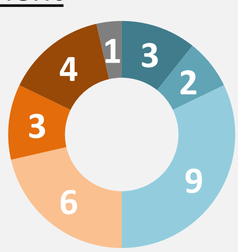
Q Identifying potential risks to the environment as a result of emissions from Hydro One's own operations, and investing in mitigation strategies to ensure compliance with all applicable environmental regulations consistent with the Government of Ontario and the Government of Canada. **How important an outcome is environmental stewardship?**
[asked of all respondents, n=103]



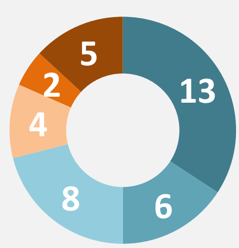
NOTE: No response (n=1) not shown

Business Segment

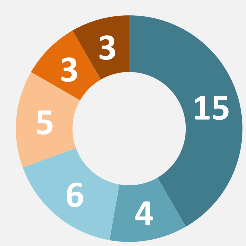
LDC



End User

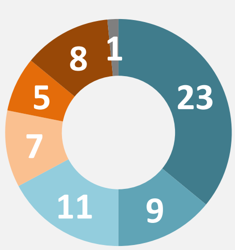


Generator

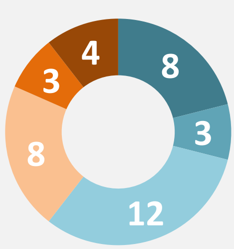


Single vs. Multi Circuit

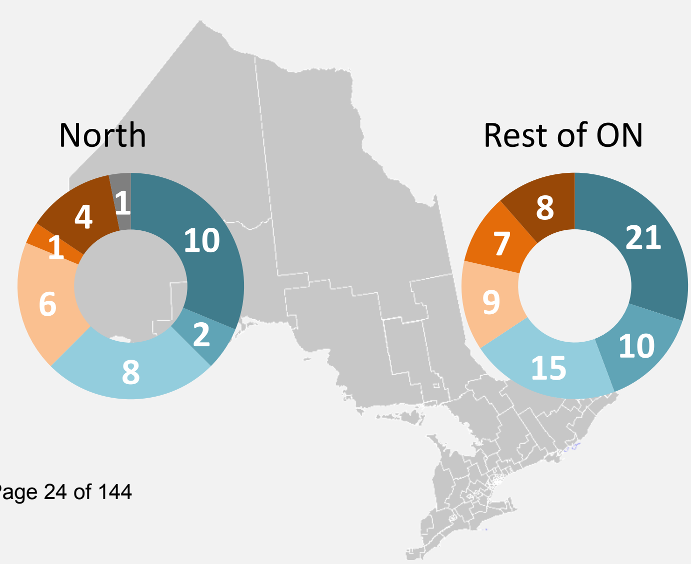
Single



Multi



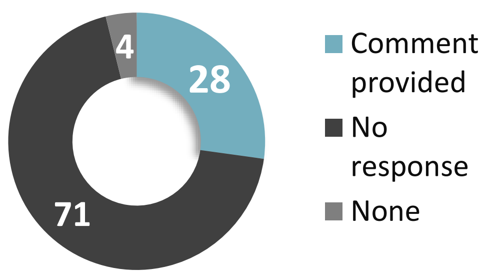
Region



Additional Outcomes (1):

Majority of respondents had nothing to offer on missed outcomes; among those who did, cost and capacity/expansion are top mentions

Q Are there any outcomes we missed? Please use the boxes below to add them, and then the slider to rate their importance.
[asked of all respondents, n=103]



System capacity - Have a transmission system with the capacity to meet the needs of our customers.

New connections and upgrades built and energized on a timely basis.

Price or cost - what is the value for money.

Costs; You will say its inferred in productivity and others. This is the reason we are in a mess.

Reduction on cost of GA.

Grid Capacity Expansion.

Response from local Hydro One team to respond to emergencies related to un-expected site power outage.

General communication about direction of HONI certainly helps me as a customer understand ramifications.

Responsiveness and personal assignment of a customer service representative for major customers.

Streamline the customer service experience to be able to reach appreciate parties efficiently.

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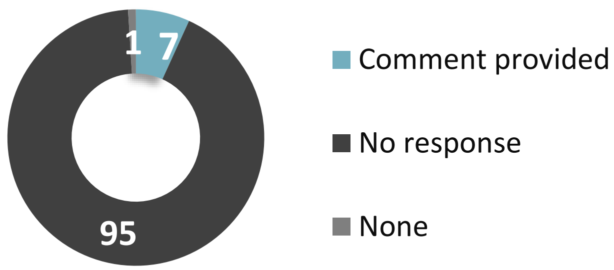
Additional Outcomes (2):
Very few were able to suggest a second additional outcome

Q Are there any outcomes we missed? Please use the boxes below to add them, and then the slider to rate their importance.
[asked of all respondents, n=103]



Reasonable cost and timeliness to provide services such as connections, transfer trips, CIAs.

Power Distribution costs go down.

Accountability and transparency - Most people can't understand their bills and costs are fixed.

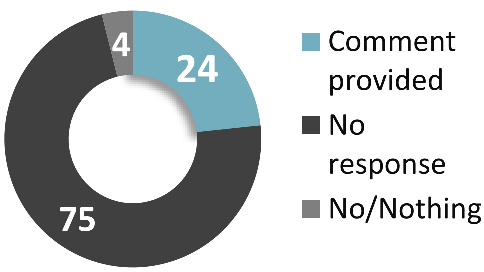
Drive for Delivery - accountable to deliver and action oriented.

Communication.

Comments:

Comments regarding customer outcomes touch on a wide variety of topics including safety, reliability, and cost

Q Do you have any specific comments or suggestions regarding any of the seven outcomes that you just rated or any additional outcomes you added?
Please fill in your response below.
[asked of all respondents, n=103]



Cost reductions should be a top priority and given serious consideration and not just lip service.

Cost estimates for work to be performed by Hydro One are extremely high. While part of the issue is the class C estimate contingency, those costs cause a lot of concern for customers considering connections for generators.

All outcomes are equally important. It is hard to have one and not the other. Ultimately we do not see the environmental stewardship piece directly at the mill site.

I like when you mention safety, the industry is very high risk and nice to see HONI as a leader.

The main outcome should be to provide reliable power at the best possible cost which should be benchmarked to a world standard to remain competitive and to make it so people don't have to choose between eating and having access to power.

As a generator it also extremely important that HONI is available to take the power and transmit it reliably.

Power Quality is an integral part of Reliability.

Ensure that there is regular communications and dialogue.

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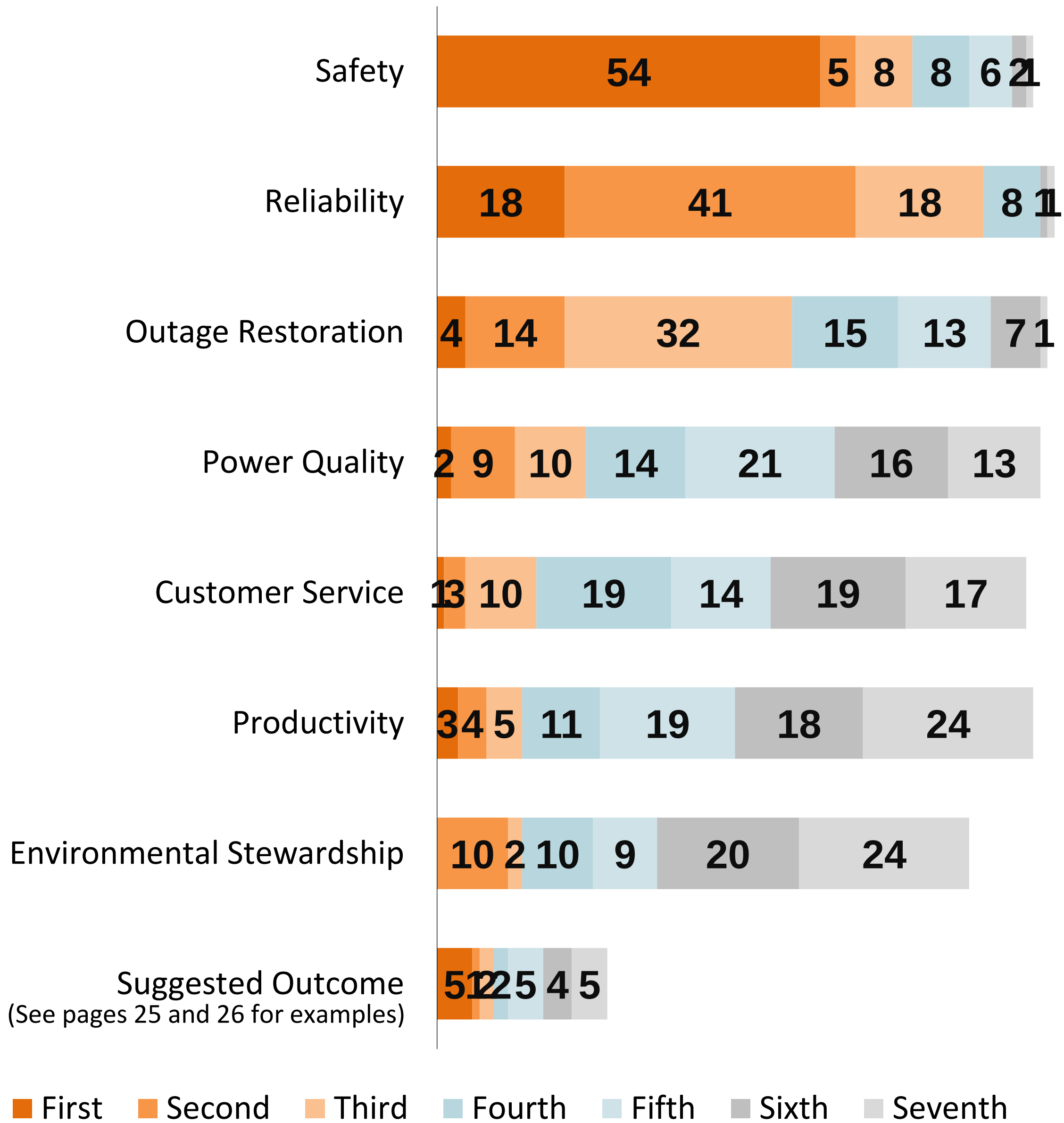
Top Priorities:

More than half rank safety as *first* priority. Rolling top 3 priorities together, reliability and outage restoration increase as priorities

Q While all the outcomes listed are important to many customers, planners set priorities among different outcomes. The purpose of this section is to help Hydro One set priorities as it prepares its business plan. Which priorities should they focus on first?

Please rank your top priorities from the list below.

[asked of all respondents, n=103]



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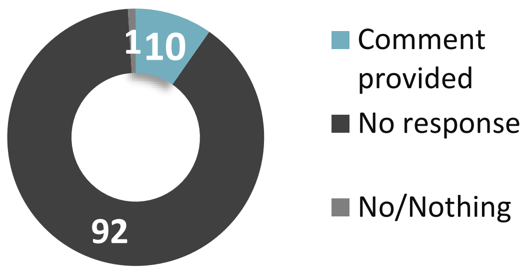
NOTE: No response (n=16) not shown.

Comments:
Most did not provide any additional comments following the customer outcome priority ranking exercise

Q Comments in response to ranking customer outcome priorities:
[asked of all respondents, n=103]



Customer Service is affected by not only the customer service through communications and follow up but it is driven by the quality and reliability of the service of supplying electricity.

The focus on environmental steward ship and the solar and wind ventures it generated where ill conceived and poorly planned and have costs significant hardship on the citizens of Ontario . Although important it was very badly managed.

Note that although power quality is on the bottom it is also extremely important.

Safety and Environmental stewardship are not my interests but your employees and the governments interests respectively - as a customer I need performance improvement in all other areas and results now and need to know and trust that you have it and are going to do something on it.

As a customer, reliability and outage restoration are important outcomes. I should be able to rank those at the top without sacrificing Safety or the Environment. This survey does not give that choice.

Number one for my customers is rates. Productivity is not a direct reflection of that, but is similar.

This ranking is predicated on Hydro 1 executing these priorities - if power quality and reliability are not improved, then customer service becomes much more important.

This is difficult as they are all important.

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Pace of Investment

Pace of Investment: Summary

Customers indicate a strong preference for stable rate increases and investments spread out over time, with 74 out of 103 choosing this option over investing now (with higher rates in short term and lower future increases) or delaying investments (with lower rates in the short term and higher future increases).

LDCs show the strongest preference for spreading out investments, with all but a handful choosing this option.

Asked why they prefer this option over others, customers mention affordability and aligning rate increases with inflation. The perceived affordability of this option is viewed both from the perspective of being a business transmission customer (“Easier to forecast for business plan with stable increases”), as well as the end customer of LDCs (“This is the philosophy we have taken as a distributor ... affordability needs to be considered”).

Ten respondents were not able to make a choice on the pace of investment options presented to them. Some of these customers use phrases like “Show some flexibility” and “revisit and optimize costs” to describe what the decision depends on. Others wanted more detail about the investments and the magnitude of rate increases.

Pace of Investment:
Preamble and Survey Question

Before being asked the question about the pact of investment, respondents were provided with the following preamble:

When Hydro One replaces equipment in declining health, it has some flexibility in its pacing. We would like to understand your general views on the appropriate pacing of Hydro One's investments over the next 15 – 20 years. Hydro One can front load its capital investments, it can spread them evenly over time, or it can delay its investments.

Front-loading investments would provide some benefits in terms of more connection capacity, decreased equipment failures, increased reliability, and improved productivity and quality. This would mean higher rate increases now but lower rate increases in the future. Spreading evenly over time means some benefits are delayed but some long term savings are secured and it is more efficient in terms of staffing. Rate increases would increase at a stable level. Asset deployment costs would likely be lower using this more stable pacing philosophy.

Given the current health and demographics of the system, Hydro One can delay investments further until declining equipment conditions threaten Hydro One's ability to meet power reliability requirements. Reliability would still meet minimum standards but customers would likely experience more interruptions than today. Rates increases would be relatively low for several years but increase at a steeper rate in the future.

Following the preamble, respondents were asked the following question:

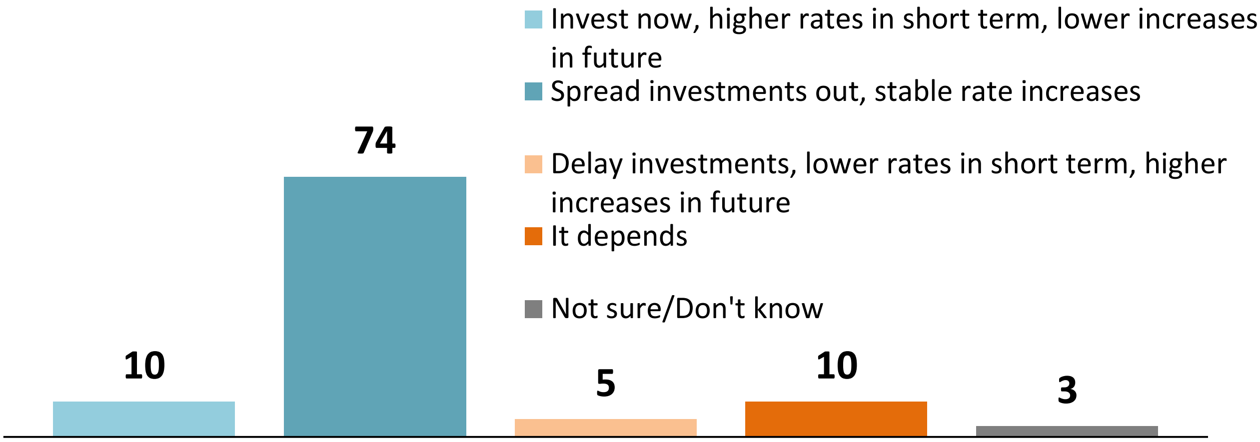
Bearing in mind the trade off between immediate rate impact, long term rate impacts and system benefits, which approach best reflects how you feel Hydro One should pace the work required to renew the system over the next 15-20 years?

Pace of Investment:

Strong preference for spread-out investments and stable increases; highest in 'Rest of Ontario' region and among Single Circuit customers

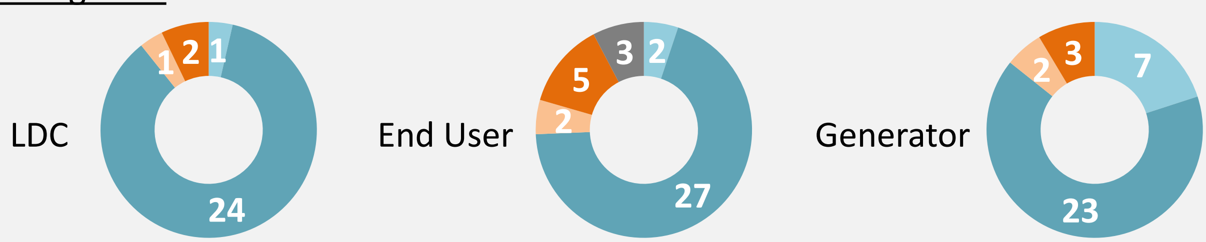
Q Bearing in mind the trade off between immediate rate impact, long term rate impacts and system benefits, which approach best reflects how you feel Hydro One should pace the work required to renew the system over the next 15-20 years?

[asked of all respondents, n=103]

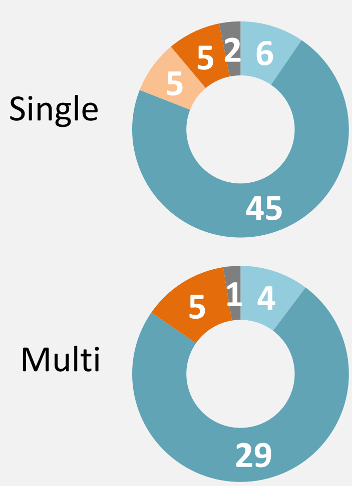


NOTE: No response (n=1) not shown

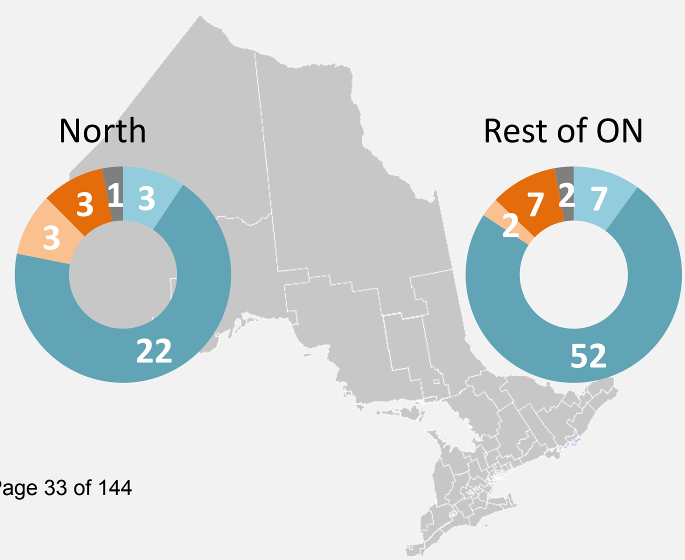
Business Segment



Single vs. Multi Circuit



Region



Invest Now:
Those who prefer to invest now appear to be motivated by the reliability risks associated with aging infrastructure

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

Invest now, higher rates in short term, lower increases in future…

Decrease in system reliability or increases in equipment failures negatively impacts our facilities operations and earnings.

Locally many assets are getting aged and reliability is already at risk. Higher capital investment now along with a push for higher productivity and lower internal cost would be the preferred approach to reduce rate impacts.

Infrastructure drives reliability.

Current state of equipment.

To increase capacity in the short term to be able to add more renewable energy to replace fossil and nuclear generation.

I say this but a change is an election away. We need the long term vision and goal the strive for.

Price only will go up if waiting.

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Spread Investments Out:

Preferences for spreading out investments seem to stem from themes of affordability and reducing financial impact for both rate payers and businesses

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

Spread investments out, stable rate increases…

Good balance.

Balanced investments so rate increases are aligned with inflation. Electricity in Ontario is extremely expensive and has put Ontario business at a significant disadvantage. While investments are necessary so are ensuring competitive costs.

Most cannot afford higher rates, and delaying will just cause future generations to deal with legacy issues.

This is the philosophy we have taken as a distributor. At some point affordability needs to be considered in capital expenditure levels year over year.

Would prefer option on invest now, but the cost may be too high, so spreading costs may be better.

Manageable to ratepayers while insuring reliability.

A spread of investments avoids putting costs to ratepayers in the future and avoids the risk that future ratepayers may be in a worse position to pay the increased rates. It also avoids the cost of frontloading the costs when there is currently much customer concern over their ability to pay. This middle alternative seems to provide a reasonable cost balance while somewhat increasing reliability risk.

Given that the current electricity rate in Ontario is among the highest in North America.

Financial impact.

Hydro is too expensive.

As a customer ourselves managing the rate increases so infrastructure investments are financed at a reasonable pace i.e. inflation plus 2%.

Less impact on cashflow for companies.

Easier to forecast for business plan with stable rate increases.

Produces more certainty in planning and rate increases.

Stable investments assuming reliability and PQ are held constant.

Over the long-term this provides the best return on investment.

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Spread Investments Out (2):

Spreading out investments can allow for reliability to be maintained while reducing financial impact

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

Spread investments out, stable rate increases…

It is unlikely that rates would ever decrease. Good practice would be to manage assets without too much of an impact on the customer and rates.

Spreading out investments allows you to prioritize as needed at a sustainable run rate, in addition to evening out the rate impact as much as possible.

I believe it's the best thing for the ratepayer. No shocks. I understand why Hydro One may see it differently, but the goal is to provide power with as much consistency in price as we can. Quick raises in price is not looked upon favourably.

Ontario residents are already suffering high energy costs.

Over half a century old, it's easier on the elderly population which is increasing to financially handle any smaller increases because of fixed income.

1) Predictability in pricing 2) Not letting the system fail

It is a reasonable approach between responding to excessive failures (by deferring investments) vs the additional cost (spreading the investment).

Preference is to have stable rate increases for financial planning provided that reliability is not compromised.

I believe that Hydro One can find internal efficiencies to help offset rates while continuing to improve reliability.

I don't believe delaying the investment would be prudent and we would feel that in the future with reliability and outage issues. I don't see our business expanding too much in the near future so I would prefer to spread it out evenly.

We cannot defer our costs to make the next generation can pay.

Its unfortunate the state of power in Ontario. Hydro One should reflect on their performance vs other provinces and states. What are we doing wrong when it costs so much to produce power vs other areas?

It's pragmatic.

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Delay Investments:
Finding internal efficiencies first is mentioned as rationale for delaying investments

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

Delay investments, lower rates in short term, higher increases in future…

Because I believe that internal productivity increases within Hydro One should be the first priority.

CUT COSTS NOW e.g. salaries by 15% to 30% for sunshine employees.

Hydro One needs to get their internal house in order before it inefficiency spends any more ratepayer dollars.

I don't agree it will mean higher increases in the future . AT least it may eliminate investments that are needed. We have made a lot of investments in the past we don't need. This will prevent that.

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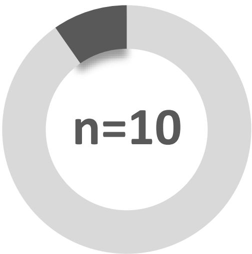
Pace of Investment (3):

Among those who say “It depends”, having flexibility in investment planning is a top concern

Q What does it depend on?

[asked of of those who said “it depends” when asked of about preferred paceof investment, n=10]

It depends



Customer connection requirements and timing of those. Show some flexibility! just because a new customer connection falls a year outside the Hydro One plan should not necessarily require the customer to pay the full advancement cost.

Plan the requirements, allow for the unexpected (which will be minimal if planned properly). Capital programs are inherently lumpy!

Safety, reliability, growth regions, new technology, innovation - it shouldn't just be an all or nothing approach.

It would have been useful if you could have quantified the magnitude of rate increases and not just higher or lower. Are you talking about 1 verses 2% or are you talking about 1 verses 10% It is hard to make a good decision until the impact is known.

Not knowing exactly what the investments are made to achieve/address and their impact/cost this question is difficult to answer in general.

I think you need to do some investments, spread payments over time, but revisit and optimize costs...ALWAYS be more productive, look for economies of scale, look to streamline and cut where people or assets are not productive and a drag on the system, literally and figuratively...have yet to see HONI do this.

A management plan that gets the most out of the team it has - I don't believe you have that yet.

Getting what you really need right (nowhere close to that yet), getting your operating costs in line (lots to do there), what your financing charges are compared to ours (we have to borrow to pay for you guys, and your rates are likely lower than ours), setting priorities that provide a level of priority for economic health of your jurisdiction vs convenience.

Reliability

Reliability: Summary

Asked what reliability means to their organization, for some customers, reliability is about having a power supply that is consistent and stable. For others, it is a lack of unplanned power interruptions. There are also some who emphasize the impact that power interruptions have on their business, both in terms of productivity and safety.

A consistent and stable power supply is mentioned more often by Generators and LDCs than End Users, and more often by Single-Circuit than Multi-Circuit customers.

Customers in the North mention no/few unplanned interruptions more often than customers elsewhere in the province, and End Users mention this more than LCDs or Generators.

When asked to rank five reliability metrics in terms of which are most important to them, transmission customers put reducing the frequency of day-to-day interruptions at the top of the list most frequently, followed by overall power quality and reducing the frequency of interruptions due to major events. Reducing the duration of interruptions (be they day-to-day or a result of major events) is less important than reducing the number of interruptions, when responses are ranked according to which is selected most often as a “first priority”, but when first, second and third priorities are added together, reducing the duration of day-to-day interruptions is almost on par with reducing the number of interruptions due to major events.

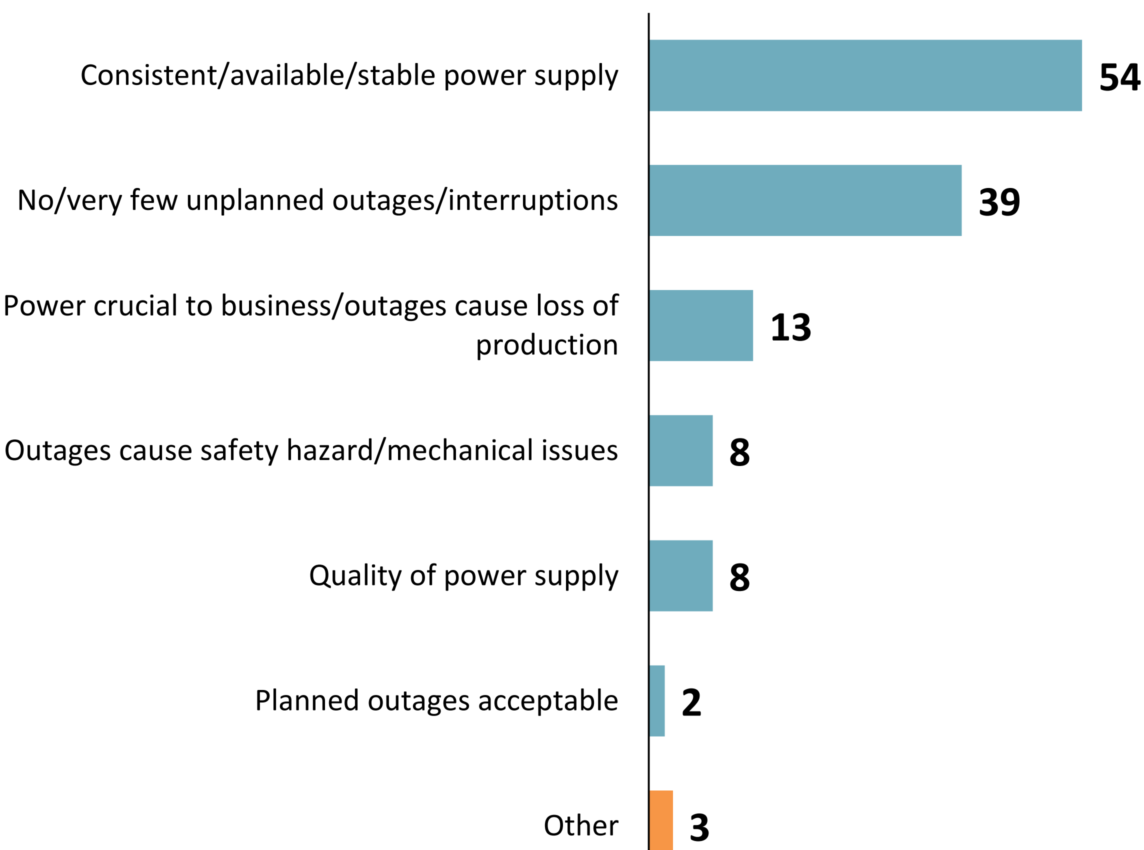
Customers were provided with a comments box in which to record anything they wanted to add on the topic of reliability. Sixteen customers recorded comments, ranging from not being able to control major events to feeling that power quality did not belong on the list as it is not a transmission issue.

Reliability:

Availability, consistent supply, and lack of outages are the phrases used most often by customers to define reliability

Q We are now going to move on to the topic of reliability. The term "reliability" means different things to different people, so before we move on, please describe what reliability means to your organization. When you are talking about transmission reliability, what does that mean to your organization?

[asked of all respondents, n=103]



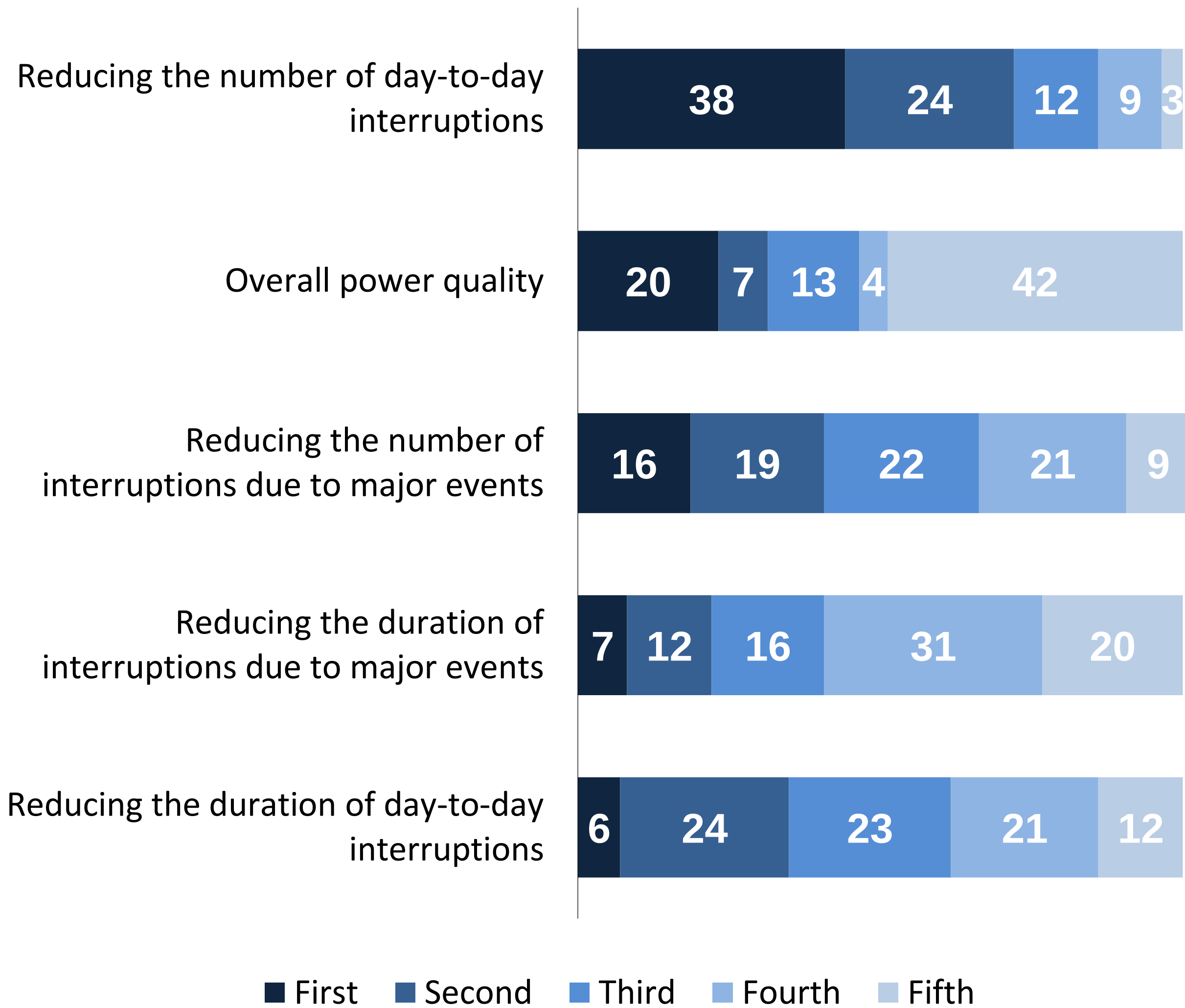
NOTE: Total is greater than 103 due to responses being coded into multiple categories

Reliability Priorities:

Reducing interruption frequency appears to be more important than reducing interruption duration

Q Reliability has a specific meaning in electricity, but often when customers talk about reliability, they are also talking about power quality (defined as delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform). Below is a list of five items that are often included when people talk about reliability. In addition to power quality, when people raise concerns about interruptions they often draw a distinction between interruptions that are experienced during normal day-to-day operations versus interruptions that occur during major events such as severe storms. **Please rank the following reliability items in order of which are most important to your organization.**

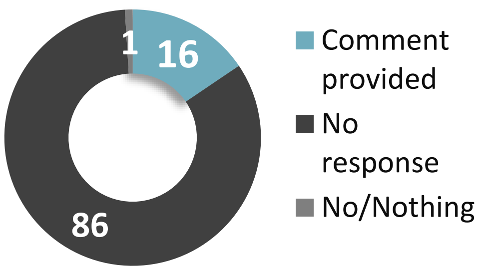
[asked of all respondents, n=103]

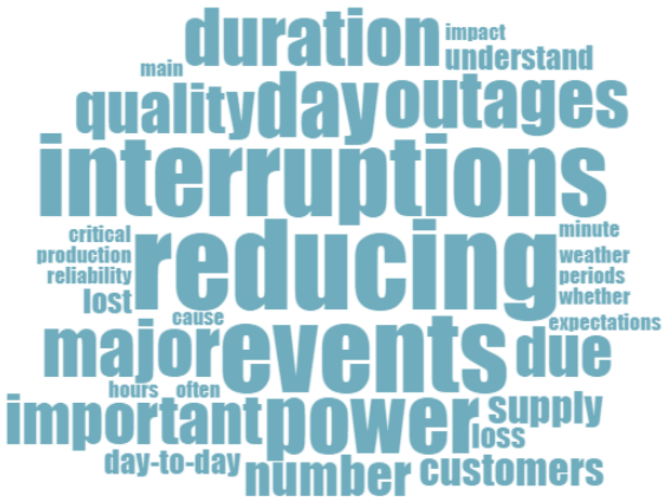


NOTE: No response (n=16 for first priority, n=17 for additional priorities) not shown.

Comments on Reliability:
Focus on reducing day-to-day interruptions over unpredictable major events

Q Is there anything else you would like to add on the topic of reliability?
[asked of all respondents, n=103]





I understand we do not control the weather, goal is to reduce the impact on the utility.

Major events cannot be reasonably predicted especially with global warming trends and more severe weather. The flexibility and the ability to react to the event is more important which will impact duration.

Power quality is most important to large, power quality sensitive customers while small commercial or residential customers are most concerned with the number and duration of day-to-day interruptions. Most customers have the most tolerance for outages due to major events as they can understand the reason behind the outage while the cause of day to day outages is largely invisible to most customers.

Power quality is not a transmission issue and shouldn't be on the list. Frequency and duration of outages are the key. Due planning processes for planned events is critical.

On-peak periods is our main focus and need interruptions reduced or eliminated during the on-peak periods Monday thru Friday.

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Investment Scenarios

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Investment Scenarios: Summary

Respondents were provided with detailed descriptions of four illustrative investment scenarios. These scenarios were then plotted as reference points along a line of 17 points, and respondents were asked to choose a point along that line which best represented their preferred approach for Hydro One's investments (see page 22 of Appendix 1.2). Scenario A was based on limited investment, Scenario B involved a decrease in the current level of investment, Scenario C would maintain the current level of investment, and Scenario D would increase beyond the current level of investment. Each scenario impacts reliability risk, long-term reliability and future rates.

Scenario C, which maintains current investment, decreases reliability risk, increases long-term reliability and offers level future rate increases was the single most popular choice with 25 out of 103 survey respondents selecting this option. Having the ability to choose one of 17 points along a line, 22 chose a point between Scenario B and Scenario C, and 18 chose a point between Scenario C and Scenario D. This clustering of points around Scenario C reinforces the earlier stated preference for a pace of investment which would spread investments out over time with stable rate increases.

This pattern of "clustering" on or near the point along the line representing Scenario C was common across all business segments. Generators are the only business segment where the level of support for Scenario D (n=6) approaches the level of support for Scenario C (n=8).

All respondents were asked to describe why they chose the point along the line that they did. Those who chose Scenario C used phrases like "reduces risk", "maintaining status quo would seem appropriate", "balanced and consistent", and "same health level as it is today".

Illustrative Scenarios:
Information for Participants

A preamble provided background on four illustrative investment scenarios. Each scenario was then described in detail, and a summary table (below) provided a comparative overview of all four scenarios. The descriptions of the illustrative investment scenarios can be found on pages 18 to 22 of Appendix 1.2, and a slightly more detailed summary table was available to survey participants on page 18 of Appendix 1.3.

	Illustrative Scenarios			
	A: Limited investment	**B: Decrease in current level of investment**	**C: Maintain current level of investment**	**D: Increase beyond the current level of investment**
5 Year Capital Investment	$1.8 B	$4.3 B	$6.6 B	$7.4 B
Reliability Risk	Increase in risk ~30%	Increase in risk ~10%	Decrease in risk ~10%	Decrease in risk ~15%
Long-term Reliability Impact	↓	↓	↑	↑*
Average Percentage of Key Assets Beyond Expected Service Life by end of 2023 (21% in 2019)	29%	26%	19%	17%
Impact on Future rates	Significantly higher future rate increases	Higher future rate increases	Level future rate increases.	Slightly lower future rate increases.
Average Annual Total Bill Impact – Transmission Connected Customer	0.11%	0.27%	0.42%	0.46%
Average Annual Transmission Rate Increase	1.30%	3.30%	5.10%	5.60%

* Improvement in overall long term reliability and significant performance improvement for small number of customers connected to the worst performing circuits.

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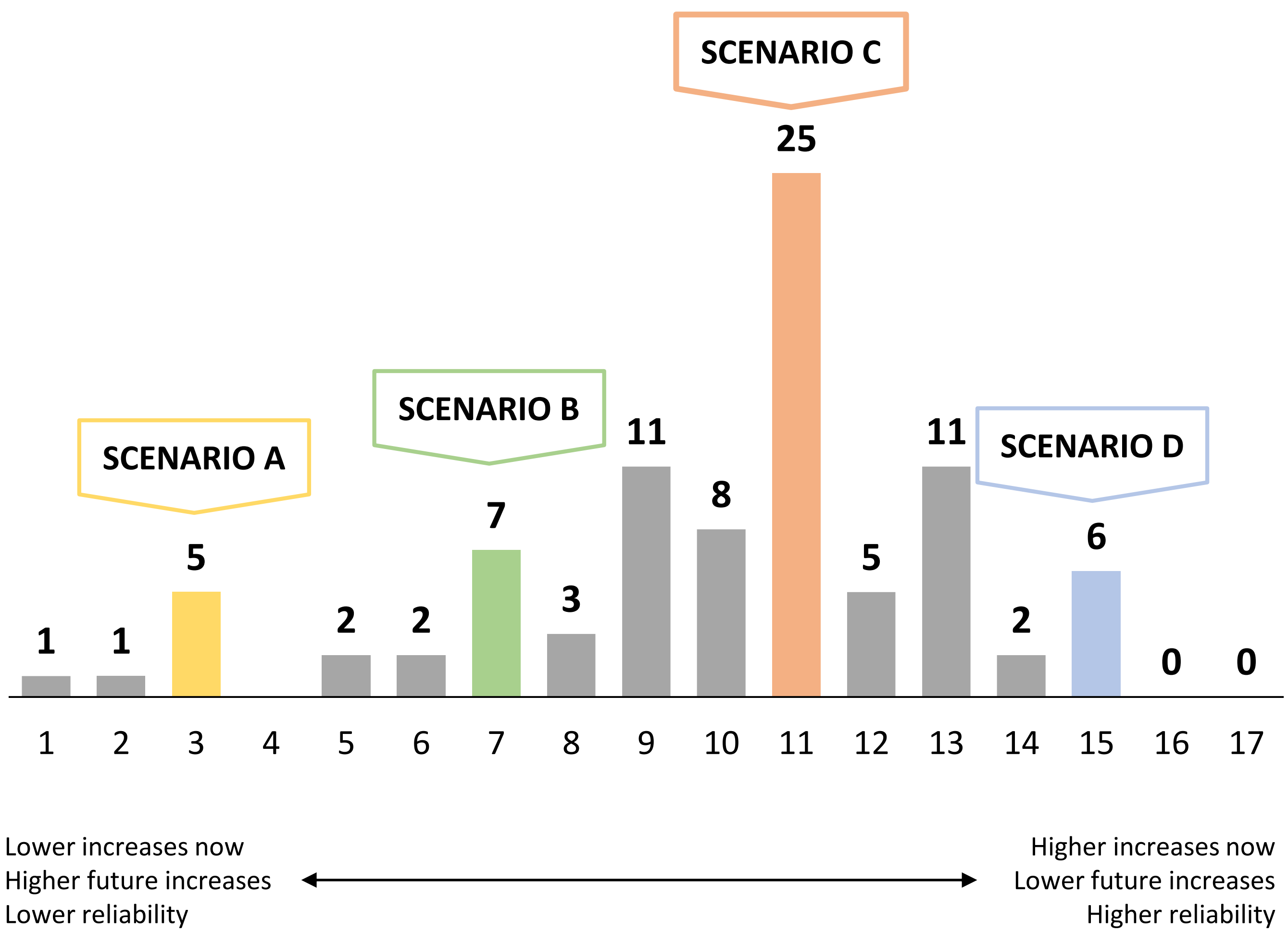
Illustrative Scenarios:

Maintaining current level of investment ("Scenario C") is the most popular scenario

Q Thinking of all the considerations outlined, please choose a point along the line below that you believe strikes the right balance between rates and outcomes. (Remember that you can choose a point between scenarios or directly aligned with one of them).
[asked of all respondents, n=103]

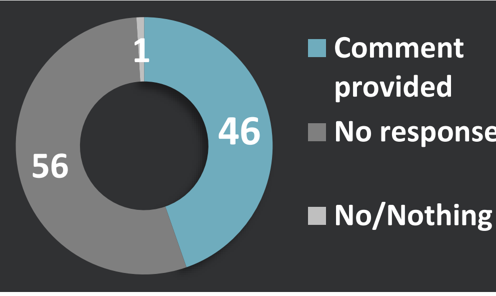


NOTE: "Don't know" (n=7), No response (n=7) not shown.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
LDC		1	1		1	1			5	6	6	1	3				
End-User			2		1		5	1	3	2	11	2	4				
Generator	1		2			1	2	2	3		8	2	4	2	6		

Comments:

Point 3 - “Scenario A” preferred by those who want to limit rate increases



Please use this space to tell us why you chose the point you did.
[asked of all respondents, n=103]

Point 1

Clever OEB type presentation Ontario in very fragile economic condition   Just focus on cutting cost There is not as you imply direct correlation between cost reduction and reliability.

Point 2

1) Hydro One is inefficient and needs to sort out their internal processes and find greater efficiency. 2) There is nothing in this plan for innovation. Why would they invest in Tx infrastructure without a plan to manage the two-way flow of electricity that distributed generation will bring in 10-15 years. The last thing anyone wants is billions of $ in distressed.

Point 3 – “Scenario A”

I am prepared to take on more risk as we get the cost envelope sorted out and I am not willing to accept that rates would only change from .11% to .46% between scenario's when costs to the public have been going up by double digits per year for many years. In addition I am not prepared to accept that managing the rate of investment now will necessarily result in significantly higher future rates. The whole system has to take responsibility for the costs the public is struggling with NOW!

Scenario A seems the most favourable at this time; companies are very cost focussed and margins are currently very tight.

Low rates a priority and managed risks - information is imperfect and so the best investment is to get better data/information while you have the time to drive better investment outcomes while living within a cost affordability index. Are you getting the right bang for your investment today? That data was not made available - can you assume you will get more for the money you are investing?

Point 4 – No comments

Point 5

Keep increases at inflation.

Point 6

You should manage your business to be at or below the annual Canadian index price increase and still be reliable. Actual rates are already very high. We pay anywhere between $120-150/MW which is too high.

I recognize HONI has very difficult choices to make. However, it is very difficult to support a transmission rate increase that is greater than 1.5 times CPI

Comments (2):

Point 7 – "Scenario B" preferred by those who acknowledge the current state of rates

Q Please use this space to tell us why you chose the point you did.
[asked of all respondents, n=103]

Point 7 – "Scenario B"

Hydro One is unfortunately operating in one of the highest rate markets in North America. Normally higher increases could be tolerated, however with the current state of the electricity market reasonable rate increase are expected, even if it comes at the cost of degraded reliability. This is ultimately due to current and previous provincial governments however Hydro One is forced to take this under consideration.

We're on unreliable lines so we'd like some investment in those lines under any scenario. some is more than what we've seen in recent years. with upward pressure on rates, we'd be hard pressed to call for much more reinvestment than B.   I'm wondering about the capital estimates and whether or not there is any room for efficiencies within?

Balance the annual rate increase based on risk.

Point 8

Transmission costs are already too high. More needs to be done to ensure the investment $$ are being spent wisely.

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Comments (3):
Point 9 preferred by those who are looking for a balance between improving reliability and the cost of doing so

Q Please use this space to tell us why you chose the point you did.
[asked of all respondents, n=103]

Point 9

Best balance of costs vs benefits.

Chose the middle, trying to find a happy medium, so that we try to fix the mess we are in efficiently and cost affective as possible. However the rate increases is to high but we can't keep delaying either creating a bigger problem for future etc.

Reliability needs to improve but rate increases need to be balanced as it effects our operating costs.

We want a decrease in reliability risk and not too much increase in rates.

I do not agree with Hydro One's premise that there should be increases in Hydro rates amongst all the options. Like any other business; Hydro One needs to improve how it runs its business; how it seeks innovative answers; how it can deliver the same or better service for less money. I fundamentally disagree with all the options above; Hydro One has to stop acting in a way that it think it is entitled to more money or else the lights go out; Hydro One needs to start thinking like all other businesses; get lean; lower costs; meet customer expectations. The people and businesses of Ontario shouldn't have to keep paying for Hydro One's excesses. Rates should be kept constant; and the service should improve for that cost moving forward.

Preference would be investment close to scenario C but at lower transmission rate increase. i.e. Hydro One should look into improving its own efficiencies or finding ways to obtain the required funds to achieve scenario D or at minimum Scenario C's goals without significant increases to the transmission rates.

Significant investments have been made over the last five years to allow for DG resources to be connected. My expectation is that the rate of investment can now be curtailed back some.

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Comments (4):
Point 11 - “Scenario C” as a reference point is the most popular choice

Q Please use this space to tell us why you chose the point you did.
[asked of all respondents, n=103]

Point 10

The costs are a major input into these evaluations. A TS decommissioning was quoted at over $10M, transfer trip for a DG a few years ago was $180k is now being quoted at $400k, rebuilding a TS is being quoted at $38M. The choice is really C with an A rate increase.

Internal savings and efficiencies must be considered (salaries) to minimize rate increases. Increases in the 2 to 3% range combined with internal savings should net to Scenario C. This should be the goal.

This rate should still enable you to decrease the risk without a significant short term rate increase.

Maintains the average percentage of key assets beyond expected service life constant.

Point 11 – “Scenario C”

Do not want to see any service supply or reliability deteriorate from the current state.

Increased reliability, levelled rates.

It combines all four scenarios into one with moderate rate increase, high reliability and moderature future increases.

It meets many of the things and it's a substantial capital investment, but it has a lot of things moving in the right way. Decrease in reliability risk, improvement in long-term reliability. Fairly level future rate increase.

Maintaining the current level of investments will provide the planning and necessary funds for equipment is replace/upgrade as required to ensure reliability of power supply

Reduces risk, reduces the number of assets beyond expected life, cost increase is high, moving to Scenario D does not reduce the risks that much more based to cost. Selecting Scenario A or B will put our distribution system at to high a risk.

Decrease on reliability risk while levelling future rate increases.

The current level of reliability is acceptable therefore maintaining the status quo would seem appropriate.

The current situation is in part the result of a deliberate reduction in re-investment in the mid 1990's to mid 2000's which has resulted in equipment beyond service life. If reliability levels are to be maintained or improved, then a balanced and consistent approach is required.

Comments (5):

Point 11 – "Scenario C" preferred by those are focused on reducing reliability risk and improving the long-term health of the system

Please use this space to tell us why you chose the point you did.
[asked of all respondents, n=103]

Point 11 – "Scenario C" (Cont'd)

This scenario keeps the transmission system at about the same health level as it is today and while the transmission rate increase is moderate, the overall bill impact is small and likely tolerable by most customers.

To maintain a consistent cost (although increased) with a higher reliability.

There is a lot of old components that need replacing already. reducing spent $'s will not enhance current performance.

Point 12

The system already has a health percentage of aged equipment and with the increasing reliance on the transmission system to achieve the government's environmental goals, reliability will only become more important.

Point 13

Ideally, the rate increase would be inflation plus some nominal percentage. However, if 3.3% results in a material decrease in service capability, this new information suggests that the next highest level of investment is appropriate, thereby putting this somewhere in between Scenarios C and D.

Point 15

Best choice overall from reliability and long term cost perspective

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Questions for LDCs

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Questions for LDCs: Summary

Local Distribution Company (LDC) customers (n=28) were asked a series of supplementary questions in order to provide them an opportunity to respond with consideration to the needs of their customers.

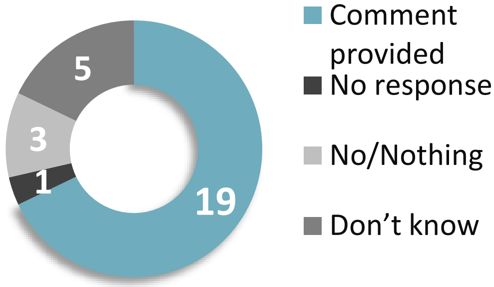
In response to an open-ended question, LDC survey participants identified costs and local support as the primary areas where they feel Hydro One can do more to help them meet the needs of their customers.

One LDC respondent, whose company provides electricity to First Nations and/or Métis communities, expressed their opinion that northern communities deserve more attention as the single-circuit connections result in vulnerabilities regarding power supply and interruption.

Eleven of the 28 LDC survey participants reported that their responses to Hydro One's transmission customer engagement survey were informed by their own customer engagement activities or other customer research.

Questions for LDCs:
Reduced costs and local support are where LDCs would like improvement

Q Is there anything in particular you feel Hydro One can do better to help you meet your customers' needs?
[asked of all LDC respondents, n=28]



It would be helpful if Hydro One were able to provide more reasonable cost estimates for their work. In past years, Hydro One was known for high costs of work and had an active program to reduce their costs of doing business. That effort seems to have waned now and costs have gone back to levels that many customers feel are too high.

Improve reliability in smaller rural communities, reduce engineering costs for distributed generation projects. Reduce operating, maintenance and administrative costs as a whole and pass the savings onto the customer base.

Consider both the financial and reliability impact of your actions on our customers.

Increased pre-planning for joint investments with the LDCs. Improve project management to achieve project milestones on time. Better transparency of costs associated to projects requested by the LDC for Hydro One to complete.

Communication and coordination of TS work requires significant improvement.

Better planning of maintenance outage notifications. Costs need to stabilize while at the same time allow for development of new loads in rural areas at costs that are reasonable and not prohibitive. Don't try and push normal maintenance and replacement costs onto new customers.

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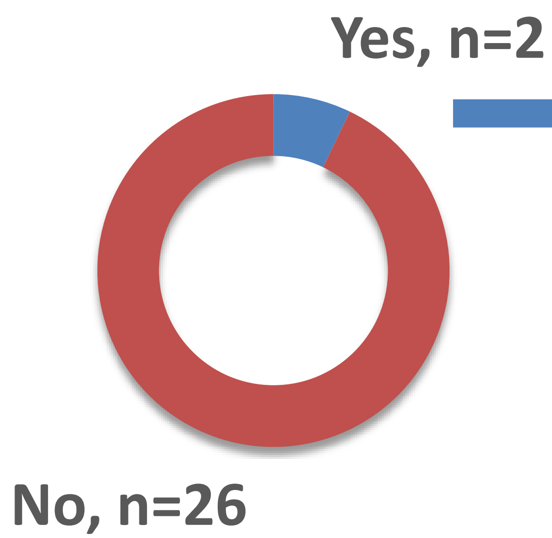
Questions for LDCs (2):

About a third report that their responses were informed by prior research

Q Does your company provide electricity to First Nations and/or Métis communities?
[asked of all LDC respondents, n=28]

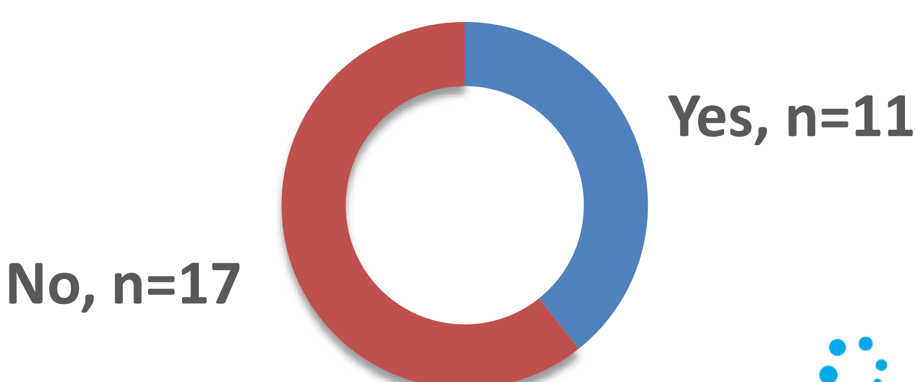


Q Is there anything in particular you feel Hydro One can do to better serve the specific needs of First Nations and/or Métis communities?
[asked of all LDC respondents who serve First Nations and/or Metis communities, n=2]

No.

The northern single circuit communities deserve more attention as they are more vulnerable in terms of supply and outage response.

Q Were your responses to this survey informed by your own customer engagement activities for the purposes of a rate application, or by any other customer research?
[asked of all respondents, n=28]



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How Did We Do?

How Did We Do?: Summary

The rate of participation and the fact that all who started the survey went on to complete it suggest that transmission customers are eager for an opportunity to provide Hydro One with their input on future business planning.

Most survey participants (n=81) had either a “very positive” or “somewhat positive” overall impression of Hydro One’s transmission customer engagement. Only three reported a negative impression.

In terms of volume of information, most (n=78) felt that Hydro One provided “just the right amount” of information for the engagement.

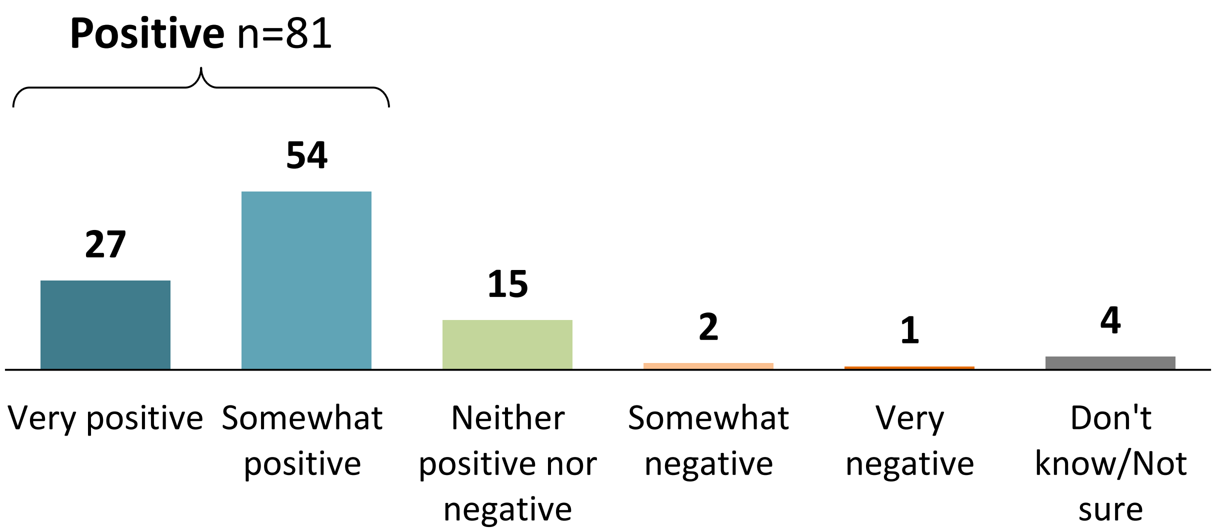
Further, only a handful felt there was any content missing that they would like to have seen included. Mentions included cost of service/efficiency planning, breakdown of necessary investments, and benchmarking information. Two participants referred to “dishonest/skewed conclusions”.

Asked if there is anything they would still like answered, a handful of participants would like details on Hydro One’s plans to improve reliability, to drive cost savings, and to improve customer service.

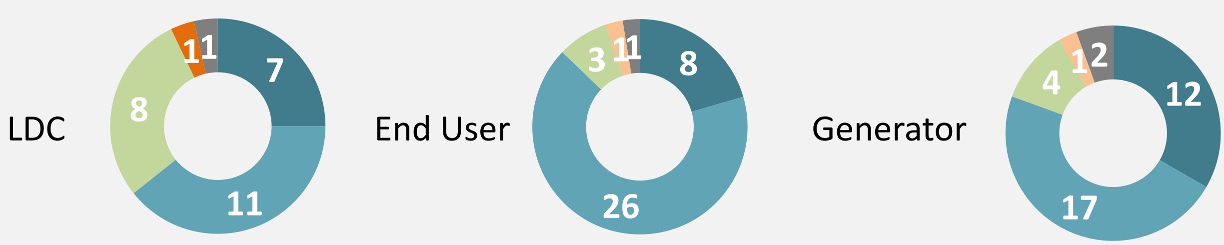
While few offered an opinion on how they would prefer to participate in future customer engagements, most of those who did comment said they would prefer the current format. A few mentioned in-person interviews.

Overall Impression:
Most rated the Transmission Customer Engagement positively

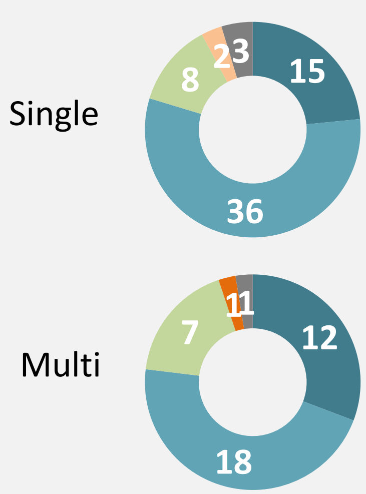
Q What was your overall impression of the Transmission Customer Engagement?
[asked of all respondents, n=103]



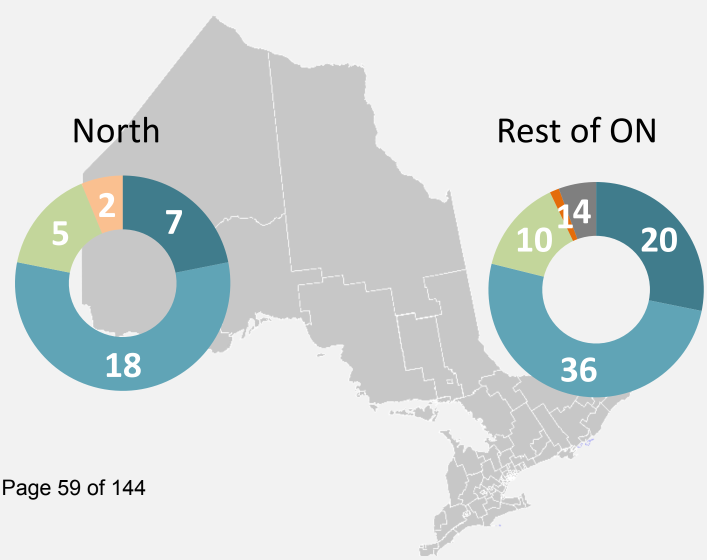
Business Segment



Single vs. Multi Circuit



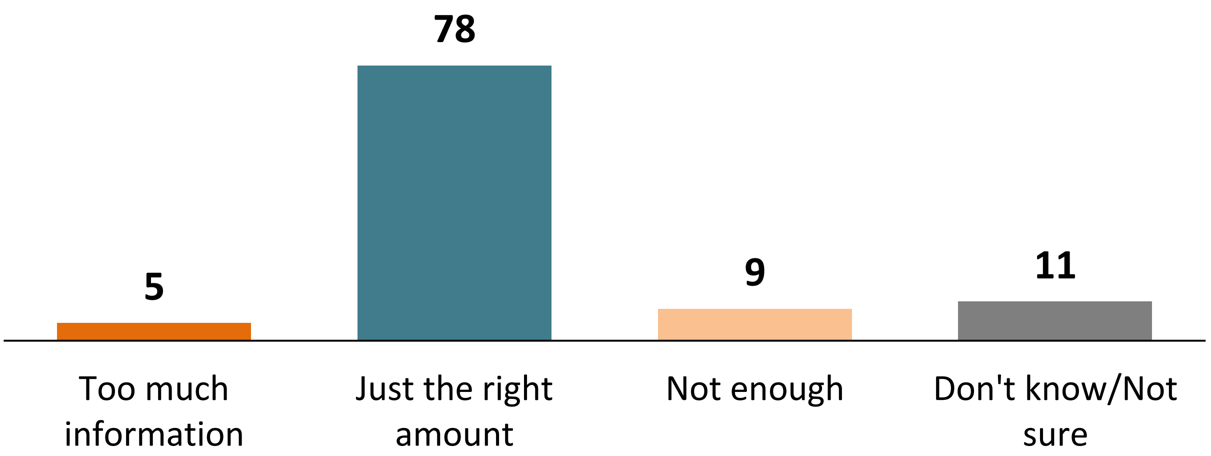
Region

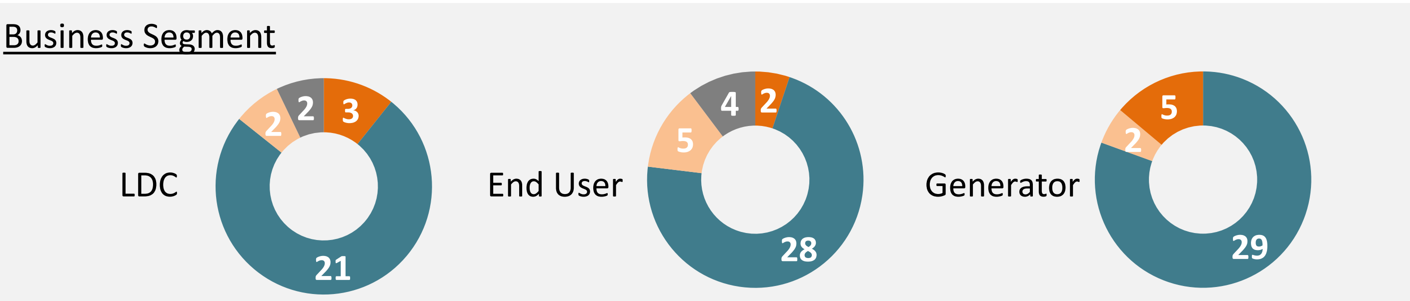


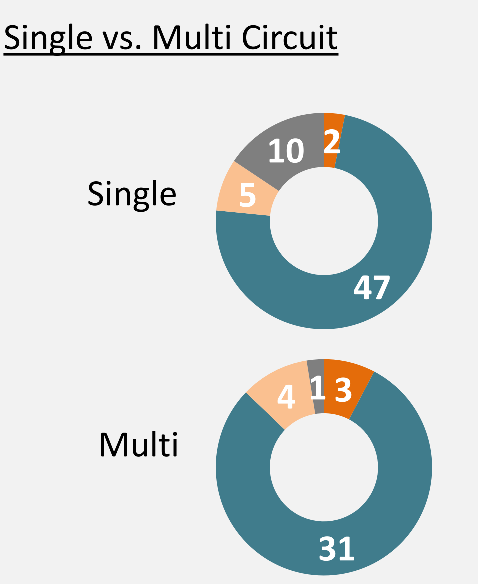
Volume of Information:

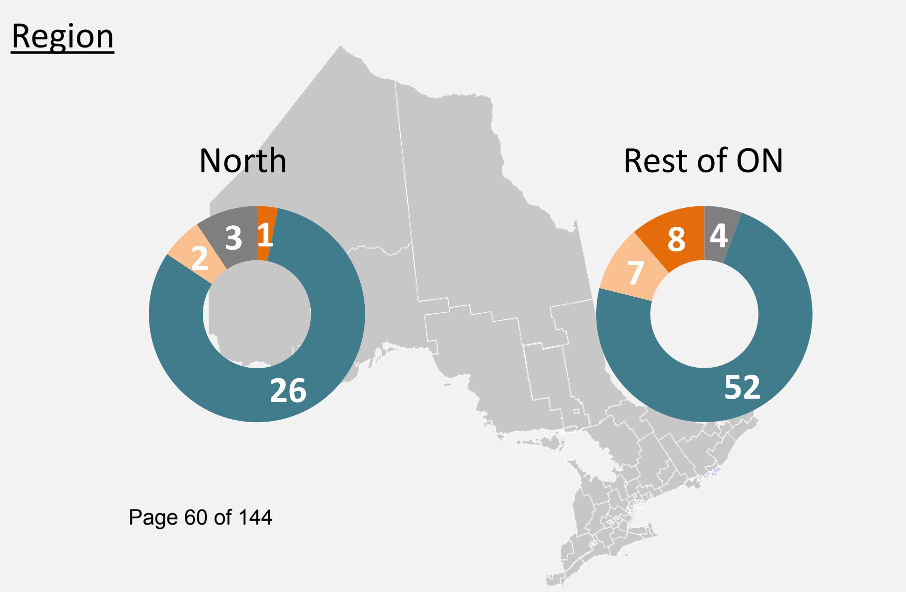
Most felt that "just the right amount" of information was provided

Q Did Hydro One provide too much information, not enough, or just the right amount?
[asked of all respondents, n=103]



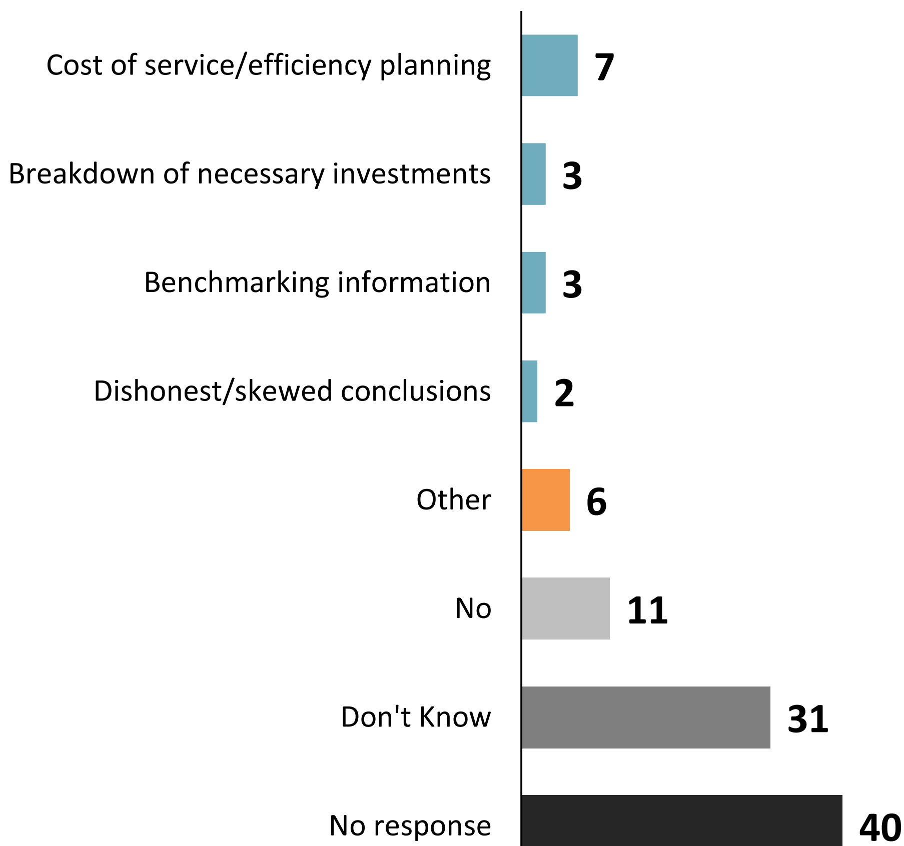






Content Covered:
Very few comments; top comments related to cost of service

Q Was there any content missing that you would have liked to have seen included?
[asked of all respondents, n=103]



Outstanding Questions:
A few comments on reliability, cost savings, and communication

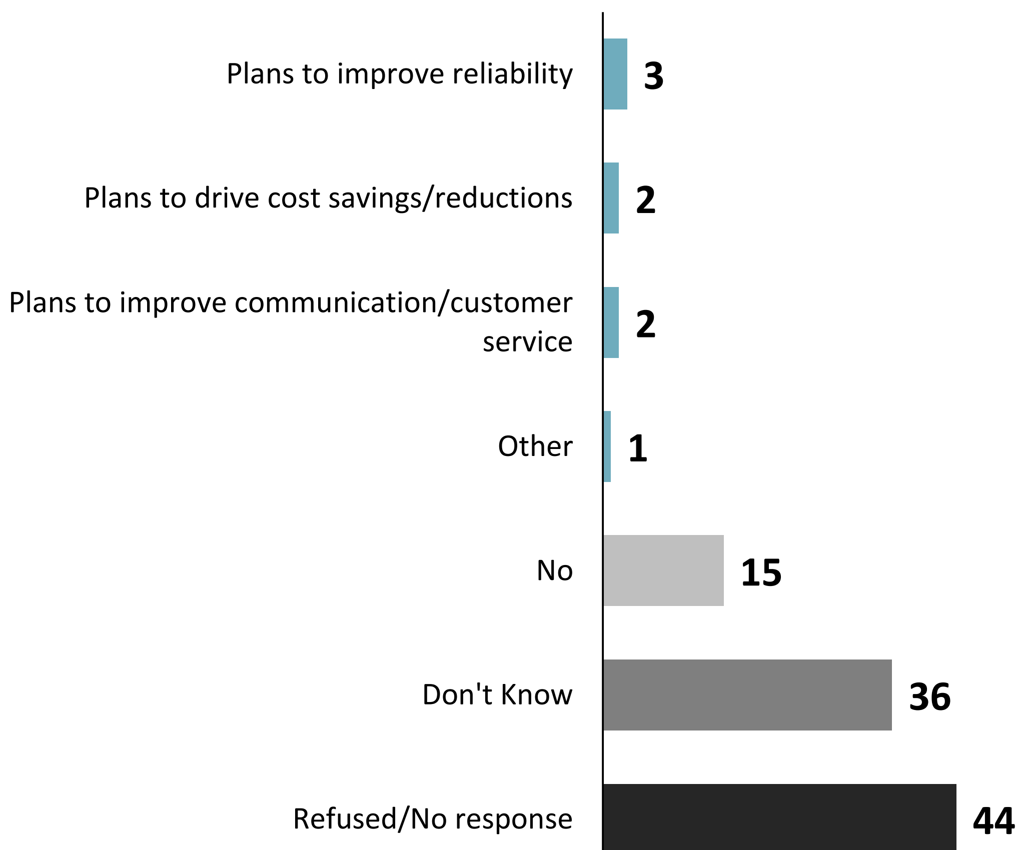
Q Is there anything that you would still like answered?
[asked of all respondents, n=103]

I would like to be able to review and understand the Hydro outage summary. Why is it so cryptic, it should be very transparent and not require an interpreter.

Please ensure to pass on the current level and expectations of customer focus to new employees of HONI; communications is key and appreciation of the cost to customers when the grid is not available.

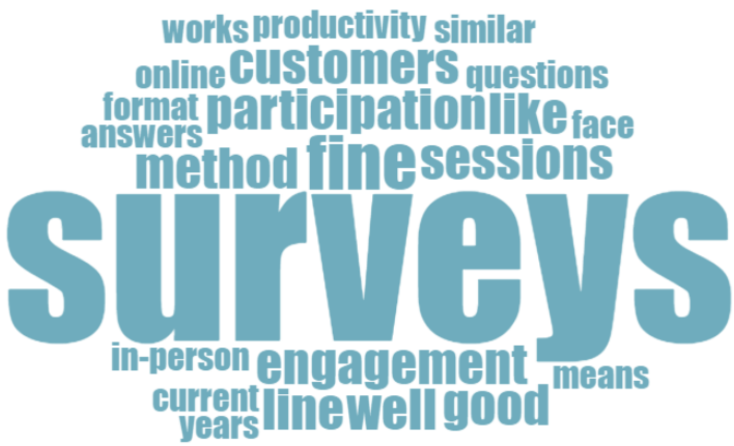
When are you releasing the plans? Will there be any dialogue on rates and where will we get a chance to review those comments?

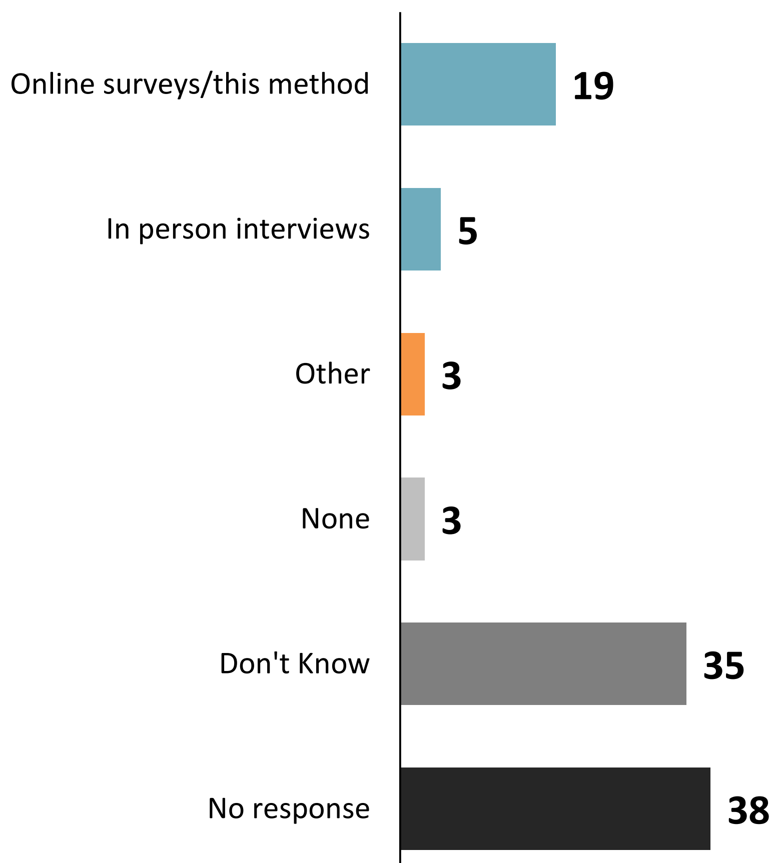
Innovation and lean management of Hydro One to drive cost savings and improve performance.



Future Customer Engagements:
Those who commented tended to prefer the current format

Q How would you prefer to participate in these engagements?
[asked of all respondents, n=103]





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For more information, please contact:

Greg Lyle
President
(t) 416-642-6429
(e) glyle@innovativeresearch.ca

Susan Oakes
Vice President
(t) 416-642-6341
(e) soakes@innovativeresearch.ca

Innovative Research Group Inc.
56 The Esplanade, Suite 310
Toronto ON | M5E 1A7
www.innovativeresearch.ca

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Appendix 1.1
Full Verbatim Responses

Suggested Improvements (1)

Q Is there anything in particular you feel Hydro One can do better?
[asked of all respondents, n=103]

LDCs

- Better Customer communication to LDC's
- communication re longer term plans
- Earlier engagement with impacted LDC's for station asset renewal projects.
- Timely contact with Account Rep to review transmission system reliability and incidents affecting [company]
- Nothing
- No.
- As an LDC, we deal with both staff from Hydro One's distribution and transmission business. We're somewhat satisfied with transmission system; but very dissatisfied with the distribution system.1) Hydro One needs to clean up the management of it's distribution system2) Maintain the existing service/performance of the transmission system3) Simplify ""event notification"": we struggle in decoding the location of circuits that are faulting.4) Demonstrate that they care about their LDC customers -- i.e. why won't Mayo come talk to the EDA? We'd listen and welcome the opportunity to work together.5) Improve their brand. When Hydro One ""screws-up"" the entire industry shares the burden of their poor customer relations. End customers blame our LDC for poor customer relationships that Hydro One has developed over the years. This makes running our LDC more difficult.
- I personally have no issues with Hydro One as the account rep and supervisors that I deal with always deal with our issues in a timely matter
- animal contact outage causes in stations - should be preventable - more can be done information sharing with outage causes and outage post mortem analysis
- More assistance with power quality investigations, especially where HONI customers are affecting our customers (i.e. HONI arc furnace customers causing voltage flicker issues for our customers)
- Upgrade facilities to allow for simple transfer to alternate circuit in the event of work required on our curcuit.
- Communication around job planning that affects our utility has been poor.
- our response is transmission based only and does not include distribution supplied locations. Better notification and planning with regards to maintenance activities would allow us to better plan and respond to our down stream customers.
- In the past year there have been a couple incidents where station supply was lost due to human error during station work. While only a couple incidents there is concern that perhaps the loss of experienced staff through retirement is manifesting as incidents.
- I would like to see the long term plan for Hydro One transmission investments to see how it fits with our business requirements. I feel Transmission Station investments should be pooled to avoid duplication
- Reduce cost of Engineering estimates. Improve reliability to rural areas. Improve communications regarding Distributed Generation projects with Local Distribution Companies. Improve power quality from transformer stations
- Work with the LDC utililities. Hydro One and the utilities are utlimately serving the same end use customer. As power system technology, communciatons, and IT technology advance at a rapid pace Hydro One must be able to be more flexible to enable Smart Grid and not to impede it. For example digital fault data is inherently available in new relays and systems. Make it simple and very low cost for LDC's to access this data. Cost transparency and no barriers. Work together toward solutions.
- Overall satisfied, however, some H1 assets are getting aged and maintenance times to return transformers back to service appear to be getting longer. Potential for future issues.
- Work closer with customers on planned outages. Resolve Middleport issue.
- there have been some concerns expressed over voltage regulation and insulators failures at the ts.
- Power Quality assessment could be streamlined. - Transmission expansion information/assessment could be done more quickly"

Suggested Improvements (2)

Q Is there anything in particular you feel Hydro One can do better?
[asked of all respondents, n=103]

End Users

- Share long term plan and how it affects my site
- Decrease the number of outages
- As a smaller industrial customer, we'd want more help / education in navigating the electricity system - particularly information and guidance on money saving programs that we're eligible to participate in (e.g. ICI)
- More direct communication with Customer
- Streamlining the process for connecting new customers would be beneficial, i.e. using one point of contact for all matters (including dealing with other agencies such as the IESO). It's a complicated process and time consuming.
- Satisfied with overall reliability but the costs make most of our business ventures uncompetitive and the lack of transparency and fixed nature of the billing makes it virtually impossible for us to effect the outcome.
- Timeliness of transmission station upgrades and renewal.
- Line Maintenance needs improvement due to two recent Sky wire failures.
- Continue to maintain the distribution equipment.
- Lower Costs
- be more reliable
- Response time to outages in [town] that require a crew to be dispatched from London is too long.
- Voltage adjustments to the 115kv supply (for province-wide power/demand response) can often have significant implications to our operation.
- Address "power quality"
- Better anlaysis/control of potential impact customers changes to their power systems have on the grid.
- Understanding the true meaning of reliability and the impacts this has not only on HO customers but the impacts this has on its neighbours.
- We would have selected Satisfied if it was provided. Overall, our service and interaction with Hydro One is very good. However, the bureaucratic processes are very slow.
- Keep the power on and clean (power quality, not sourcing), and don't charge us a fortune - I'm getting a 73 Chevy and paying for a 2017 Porsche Cayenne
- Add capacitance on S2B line?
- No we are happy with your service
- Take on a customer centric approach. Recognize that large industrials are important customers. Provide proactive resolution to problems Be more flexible and less driven by an internal set of rules that make very little sense to others.
- Identify, plan and execute any mitigating factors that would improve power reliability to the mill site and [region]

Suggested Improvements (3)

Q Is there anything in particular you feel Hydro One can do better?
[asked of all respondents, n=103]

Generators

- Communication of outages
- early notification for outages (when & duration), understand this can be difficult but the more lead time the better
- Consider more flexibility in internal rules so interests of both Hydro One and their customer are addressed.
- Improve forecasting / Cost estimating capability when partnering with generators.
- The cover process is somewhat ambiguous and the cost and schedules are not particularly accurate
- Customer communication
- Better coordination of outages and associated changes to same which might affect generating stations on the same network.
- Follow up on new employees in OGCC control room
- Improve Hydro One's procurement process to minimize delays in resolving equipment issues.
- Outage planning. sometime last year, there were in total of 4 planned outages were scheduled at different time slots on the same day. which it was quite confusing. later on I contacted the Hydro One officer and go clarification.
- Plan HO outages during our low production times to limit the loss of revenue to our business
- taking into consideration the customers assets and the difficulty seasonal outages can be on the operation.
- Planning & grid control needs to get better at communicating customers. Most likely turnover or retirement has resulted in new personnel with not necessary the same level of customer service.
- "All Hydro One's responses are governed by rules No special cases taken into account Cost of any interface too high"
- Service the Seaforth T/S so we have less outages
- Coordinate planned maintenance outages - proper lengthy notice
- "Interaction between technical/engineering groups and customers early in the connection process needs to improve. Improved sense of accountability required at Hydro One. Actual connection costs coming in well outside acceptable industry variance ranges. Paying significant amounts for connection estimates that provide little value (+/-50% estimate is unacceptable from any engineering firm).No sense of urgency, unless the lights are out."
- Greater communication on outages, It is very difficult to understand what all is required or not required for outages.
- Clearer direction on how potential upcoming outages affect the customers and for how long.
- Outages - unknowns and changes have been issues...last minute they just asked us for an outage to connect another windfarm with <30days notice on a project in the works for the past 3 yrs. Rates for remote power supply are incredible...bringing the total cost to nearly $0.25/kwh for our stations service for our switch station!
- Estimation, planning and engineering could be more proactive with generators. A lot of delay in getting cost estimate and work planning are having huge impact on our business.
- The distribution line running between [location] and [location] seems to have a number of extended outages which does cause us some headaches.
- respond faster to inquiries
- Plan outages better and work in better with clients to minimize impact on their business
- Ensure reliability of supply by ensuring equipment supporting our plants is maintained to highest standard. Ensure management and training of staff supports safe and error free operation of equipment supporting our plants particularly the nuclear fleet.

Performance Metrics (1)

Q How do you know if Hydro One is doing a good job for your business?
[asked of all respondents, n=103]

LDCs

- provides reliable supply and responsive service
- The transmission planning will dovetail into the distribution planning process to drive overall system efficiency.
- Timeliness of response to inquiries. Delivery point reliability improvement year over year.
- We haven't had a total loss of power in the last few years due to material degradation or anything such like that
- Timely responses from inquiries Outage frequency and duration is minimized Generally helpful and courteous staff
- Availability of Executive staff to discuss matters, field staff willingness to assist when needed, open minded, willingness to resolve issues
- good communication and timely responses
- Reliable service.
- Loss of supply statistics
- Win back end-customer confidence and improve its brand.
- same as above the people that I deal with always either answer the phone right away or call me back as soon as they can
- Several points to consider - level of engagement on issues - staying current and open communication, level of effort along prevention - are you really doing the simple things, are you easy to do business with, can you actually get things done when you say your going to do it.
- We can gage the performance of the HONI system via the number of outages due to loss of supply
- Keeping the supply of power on
- Few outages, either planned or unplanned
- Reliability and costs are the primary drivers in the measurement of performance.
- We look at overall reliability as well as Hydro One's understanding and explanations of the incidents that have occurred.
- We measure reliability based on Loss of Supply. Quality and timeliness of responses from Distributed Generation and Engineering groups.
- Reliability, costs, general customer service, responsiveness, operations service and interfaces, ease of doing business with, relationships. Enable the LDC to forward their objectives.
- Reliability to date has been good, however, increasing frequency/duration of reduced redundancy due to extended maintenance periods. Resulting in higher potential risk exposure for customers.
- No interruptions in supply and no voltage issues.
- Reliability of supply.
- - based on reliability (is excellent)- responsiveness to queries

Performance Metrics (2)

Q How do you know if Hydro One is doing a good job for your business?
[asked of all respondents, n=103]

End Users

- Unplanned outages are minimal, good communication on maintenance being completed
- They are very communicative
- Power Supply reliability
- Forced outages are reduced and power quality is improved.
- Reliability is important but at a cost that makes us uncompetitive and sends jobs abroad is not sustainable and will hurt all citizens of Ontario
- When100% availability is achieved
- Great customer service by providing assistance after failure of [company] Power Transformer T5.Greatly improved communication of shutdown work, long term planning needs etc.
- Reliable electrical power supply.
- Costs to businesses are kept in control. Evidence that cost control at Hydro One is in place and effective.
- Power service is reliable and I seldom receive any calls/complaints from our operations groups. Also, our account manager, Jim Perpick does a great job of keeping us informed and following up on any issues we raise with him.
- if I do not have to call them
- We are provided with the reliability information from our Network Management Officer.
- responsiveness to reporting requests, capital projects and market data. Very pleased.
- Electrical outages are rare and when there is an outage they are quick to respond and communicate the outage
- Number of outages my business experiences or individual equipment trips due to voltage sag
- Number of power interruptions that occur.
- Open dialogue and regular face to face visits reassure us HO understands the impacts of safe reliable operations
- 1) No unplanned outages and consistent power quality. Score 8 out of 10.2) Supportive in planning and outage response. Score 9 out of 10.
- The power stays on, your sags, swells, harmonics etc do not destroy my instrumentation, and the cost of distribution is strongly competitive with what is charged by other jurisdictions in North America in which are situated my competitors who are trying to put me out of business
- Willing to meet with us to discuss our problems. Do everything possible to keep us supplied with power. Upgrading the S2B line in the past few years.
- We seldom loose production because of hydro outages
- My power is still on
- Probably if there was very little noise about Hydro, we'd know that Hydro was doing a good job.
- Interruptions are at an absolute minimum and wherever possible with as much advance notice as possible.
- Power reliability and quality issues reduce to once per year.
- reliable supply of electricity at a reasonable cost
- Our electrical department informs us of any issues with Hydro One and how things were handled to resolve
- Good communication, fast response. Good job guys!

Performance Metrics (3)

Q How do you know if Hydro One is doing a good job for your business?
[asked of all respondents, n=103]

Generators

- No surprises
- in simple terms as long as the electricity runs through the lines and there are no disturbances causing issues or damage to our equipment then everything is good
- Regular communication at all level between hydro one steakholders for ongoing projects and maintenance activities on customer site.
- Sustained, reliable electricity delivered to our door. Our joint work - when the actuals are more in line with the plan, be it outages or length of outages, and cost.
- Reliability, responsiveness
- This survey is a small step forward in Hydro One determining the needs of its customers.
- When I don't hear about any business interruptions or scheduling conflicts.
- I think yes. Never had problems so far.
- They work with us in outage management
- Performance is based on Hydro One's ability to provide its service reliably and implications to our operations.
- stable grid system, less impact on the customer side are all we need.
- If the lines remain open for business and interuptions are held to a minimum
- Timely and accurate billing and reconciliation. Reliable power.
- Effectively communicating and ensuring to work with customers to minimize impact of business interruption
- that the delivery of Hydro is reliable
- Fewer outages
- Some communication on outages
- By the way that Hydro One coordinates planned equipment outages with the customer needs.
- No metrics that Hydro One is willing to provide. cant even get a detailed itemized statement for a connection to see how they performed against their estimates.
- no issues with unplanned outages, invoices are accurate
- On rates, no idea...on work around transmission doing fine, meeting with us generators every 6 months to try and best facilitate outages/repairs/upgrades
- We are working with HONI for generator connection since 2008. At that time, HONI were more proactive working with generator. Since 2-3 years it seems like there is no willing in resolving issues.
- If they are doing good then we won't have any surprise outages and/or time we can't inject into the grid.
- The reliability of the M2W transmission line is very good which is essential for our business.
- results
- Communication concerning outages; timely and accurate responses to queries; price
- We work collaboratively with Hydro one and participate in numerous committees overseeing areas of mutual concern

Suggested Additional Outcomes

Q Are there any outcomes we missed?
[asked of all respondents, n=103]

LDCs

- Timely delivery of project milestones.
- no
- Communication - transparency and timliness
- Price or cost- what is the value for money
- Costing allocations should either be socialized on the whole rate base or significant lead time to
- Easy to deal with.
- System capacity - Have a transmission system with the capacity to meet the needs of our customers.
- affordability - lower rates

End Users

- Weather risk mitigation - system hardening
- Flexibility of planned outages schedule to accommodate Customer restrictions
- Costs ; You will say its inferred in productivity and others. This is the reason we are in a mess.
- Inclusion of major customers like Dofasco in communication of future local investments
- Reduction on cost of GA
- So far none
- The slider above does not work in my browsers.
- New connections and upgrades built and energized on a timely basis.
- Responsiveness and personal assignment of a customer service representative for major customers
- Outage co-ordination with plant outages minimizing single line exposure.
- Your wages reflect those in industry, so that we don't keep losing our best people to you
- something about 'managing and accommodating growth and expansion with IESO through SIAs / CIAs'
- Response from local Hydro One team to respond to emergencies related to un-expected site power outage

Generators

- Predictable schedule preparation and execution
- no
- Grid Capacity Expansion
- COST COST
- Communication within IESO and HONI
- Efficiency of operations - reducing the bureaucracy, having decisions at lowest reasonable level
- general communication about direction of HONI certainly helps me as a customer understand ramification
- Streamline the customer service experience to be able to reach appreciate parties efficiently.
- Technology/Standard requirement
- Respect for other people's property - eg talking with property owners before accessing

Comments on Customer Outcomes (1)

Q Do you have any specific comments or suggestions regarding any of the seven outcomes that you just rated or any additional outcomes you added?
[asked of all respondents, n=103]

LDCs

- ensure that there is regular communications and dialogue
- None
- More timely response for communications and delivery of project milestones. Safety has been a concern when Hydro One crews have been working on shared ownership sites without engineered drawings under regulation O.22/04.
- Hydro One needs to fix its business processes and find productivity. I don't believe senior management in Toronto has the tools or workflow processes to manage or monitor projects efficiently in Northern Ontario. Until they sort out their internal workings, they don't deserve any rate increases.
- no
- You can do more with less on all of this - its not a trade off between money and results - we need the results described and we need it at a more affordable rate.
- Only proceeding on productivity projects that will guarantee a financial payback and reduce rates for all customers. Tried to provide feed back in suggested outcome 1 box but was limited to one line of text. Frequency of outages is a higher priority than duration when dealing with the general public
- Cost estimates for work to be performed by Hydro One are extremely high. While part of the issue is the class C estimate contingency, those costs cause a lot of concern for customers considering connections for generators.
- Cost reductions should be a top priority and given serious consideration and not just lip service.

Comments on Customer Outcomes (2)

Q Do you have any specific comments or suggestions regarding any of the seven outcomes that you just rated or any additional outcomes you added?
[asked of all respondents, n=103]

End Users

- Safety and Environmental Stewardship are "table stakes". If they can't delivery these 2 outcomes, they have no business operating a transmission system.
- The main outcome should be to provide reliable power at the best possible cost which should be benchmarked to a world standard to remain competitive and to make it so people don't have to choose between eating and having access to power.
- The "extremely important" responses for my organization are related to our activities which are primarily linked to [removed for privacy]. Were we primarily an office accommodation portfolio, the responses would have been less important.
- We have observed improvements in overall customer service.
- Productivity should be a key focus at Hydro One. There is little evidence that this is a consideration at any level in the organization
- Power Quality is an integral part of Reliability.
- Some of these question miss the mark 1.I don't care about productivity; I care about costs going down; 2. If power didn't keep going off, then I would not care about customer service 3. Safety and environment and politically correct questions - don't kill anyone and don't poison the planet; otherwise, get on with the job (do not use these answers as a license for expanding PC topic bureaucracy) 4. Once we are out, restart takes hours anyways; we are more concerned with not going out, then with outage length - based on past performance, we have had to install all kinds of back up generation already (costs are sunk - back to the 73 Chevy)
- Customer service should be accomplished through culture and not cost the rate payer anything. in fact, would mean savings to the rate payer. the rate payer has paid significantly for reduced emissions. outage restoration - we are on the longest radial line at [location] and incur 25 outages / year. this is unacceptable and costs us an estimated $6 M/year.
- All outcomes are equally important. It is hard to have one and not the other. Ultimately we do not see the environmental stewardship piece directly at the mill site.
- We have a good relationship with Hydro One

Comments on Customer Outcomes (3)

Q Do you have any specific comments or suggestions regarding any of the seven outcomes that you just rated or any additional outcomes you added?
[asked of all respondents, n=103]

Generators

- basically each and every item is extremely important, some of these are important to us as end users or generators and others are important to Hydro One as the service provider. Not sure if the questions wanted us to rank them which I thought would be more informative
- no
- Grid Capacity Expansion
- As a generator it also extremely important that HONI is available to take the power and transmit it reliably.
- Customer service & reliability is very important and your area or customer representatives have done an excellent job conveying this message to us.
- YOU MISSED COST OF EVERY ACTIVITY UNDERTAKEN BY HYDRO ONE
- No
- i like when you mention safety, the industry is very high risk and nice to see HONI as a leader
- There are still some old requirement that would need to be updated to reflect the new reallity, mainly in communication media for teleprotection.

Comments on Ranking Customer Outcomes

Q Comments:
[asked of all respondents, n=103]

LDCs

- Safety and Environmental stewardship are not my interests but your employees and the governments interests respectively - as a customer I need performance improvement in all other areas and results now and need to know and trust that you have it and are going to do something on it.
- Customer Service is affected by not only the customer service through communications and follow up but it is driven by the quality and reliability of the service of supplying electricity.
- As a customer, reliability and outage restoration are important outcomes. I should be able to rank those at the top without sacrificing Safety or the Environment. This survey does not give that choice.
- Number one for my customers is rates. Productivity is not a direct reflection of that, but is similar.

End Users

- Safety and Environmental Stewardship are "table stakes". We don't consider them outcomes that should be ranked, but rather core deliverables of a transmission company.
- The focus on environmental steward ship and the solar and wind ventures it generated where ill conceived and poorly planned and have costs significant hardship on the citizens of Ontario . Although important it was very badly managed .
- n/a
- Reduant question although most important is reliablity and productivity
- This is difficult as they are all important.
- This ranking is predicated on Hydro 1 executing these priorities - if power quality and reliability are not improved, then customer service becomes much more important.
- Note that although power quality is no the bottom it is also extremely important

Generators

[NO COMMENTS]

Pace of Investment (1)

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

LDCs

- produces more certainty in planning and rate increases
- Spreading out investments allows you to prioritize as needed at a sustainable run rate, in addition to evening out the rate impact as much as possible.
- over half a century old, it's easier on the elderly population which is increasing to financially handle any smaller increases because of fixed income
- As a customer ourselves managing the rate increases so infrastructure investments are financed at a reasonable pace ie. inflation plus 2%
- It is unlikely that rates would ever decrease. Good practice would be to manage assets without too much of an impact on the customer and rates.
- Hydro One needs to get their internal house in order before it inefficiency spends any more ratepayer dollars.
- Why cant you do more with less? Why are you trading off performance for costs - are you doing and getting the most out of the resources you have? I vote that one.
- It is a reasonable approach between responding to excessive failures (by deferring investments) vs the additional cost (spreading the investment).
- Local needs must be considered and vary
- A spread of investments avoids putting costs to ratepayers in the future and avoids the risk that future ratepayers may be in a worse position to pay the increased rates. It also avoids the cost of frontloading the costs when there is currently much customer concern over their ability to pay. This middle alternative seems to provide a reasonable cost balance while somewhat increasing reliability risk.
- I believe that Hydro One can find internal efficiencies to help offset rates while continuing to improve reliability.
- We cannot defer our costs to make the next generation can pay.
- Locally many assets are getting aged and reliability is already at risk. Higher capital investment now along with a push for higher productivity and lower internal cost would be the preferred approach to reduce rate impacts.
- Over the long-term this provides the best return on investment
- This is the philosophy we have taken as a distributor. At some point affordability needs to be considered in capital expenditure levels year over year.
- Stable investments assuming reliability and PQ are held constant.

Q What does it depend on?
[asked of those who answered “it depends” to previous question]

- A management plan that gets the most out of the team it has - I dont believe you have that yet.
- it would have been useful if you could have quantified the magnitude of rate increases and not just higher or lower. Are you talking about 1 verses 2 % or are you talking about 1 verses 10% It is hard to make a good decision until the impact is known

Pace of Investment (3)

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

Generators

- Current state of equipment
- I believe it's the best thing for the ratepayer. No shocks. I understand why Hydro One may see it differently, but the goal is to provide power with as much consistency in price as we can. Quick raises in price is not looked upon favourably.
- infrastructure drives reliability
- it's pragmatic
- Ontario residents are already suffering high energy costs.
- Decrease in system reliability or increases in equipment failures negatively impacts our facilities operations and earnings.
- Price only will go up if waiting.
- I dont believe delaying the investment would be prudent and we would feel that in the future with reliability and outage issues. I dont see our business expanding too much in the near future so i would prefer to spread it out evenly,
- less impact on cashflow for companies
- CUT COSTS NOW e.g salaries by 15% to 30% for sunshine employees
- It's real
- Because I believe that internal productivity increases within Hydro One should be the first priority
- Plan the requirements, allow for the unexpected (which will be minimal if planned properly). Capital programs are inherently lumpy!
- i say this but a change is an election away. We need the long term vision and goal the strive for.
- To increase capacity in the short term to be able to add more renwable energy to replace fossil and nuclear generation.
- Easier to forecast for business plan with stable rate increases;
- manageable to ratepayers while insuring reliability
- It isn't as simple as a broad answer above. Some items are more critical and should be completed upfront. Other assets should be sweated and delayed. New technologies and options should be considered for some investments

Q What does it depend on?
[asked of those who answered “it depends” to previous question]

- Customer connection requirements and timing of those. Show some flexibility! just because a new customer connection falls a year outside the Hydro one plan should not necessarily require the customer to pay the full advancement cost.
- I think you need to do some investments, spread payments over time, but revisit and optimize costs...ALWAYS be more productive, look for economies of scale, look to streamline and cut where people or assets are not productive and a drag on the system, literally and figuratively...have yet to see HONI do this
- Safety, reliability, growth regions, new technology, innovation - it shouldn't just be an all or nothing approach.

Pace of Investment (2)

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

End Users

- Most can not afford higher rates, and delaying will just cause future generations to deal with legacy issues
- 1) Predictability in pricing2) Not letting the system fail
- Good balance
- I don't agree it will mean higher increases in the future . AT least it may eliminate investments that are needed. We have made a lot of investments in the past we don't need. This will prevent that.
- This scenario depends on the specifics of investments, their value and benefits.
- Hydro is too expensive.
- Given that the current electricity rate in Ontario is among the highest in North America.
- ontario pay more for hydro then anybode around. How we can stay in business and compete
- Financial impact,
- Balanced investments so rate increases are aligned with inflation. Electricity in Ontario is extremely expensive and has put Ontario business at a significant disadvantage. While investments are necessary so are ensuring competitive costs.
- Prioritize, plan and execute.
- HO should look for internal savings/efficiencies before rate increases to fund not only growth but reliability and maintenance projects. This is how industry operates, we would expect the same from HO.
- Preference is to have stable rate increases for financial planning provided that reliability is not compromised.
- Folks - start doing root cause and figure out your problems - you have bought crap breakers and are now replacing them, crap ceramic insulators and are now replacing them, and crap transformers that have fried equipment vital to our operations (I'm assuming that these problems are not caused by poor maintenance done by your very lucratively paid employees). Let's figure out how much money you are wasting, and fix that first. What is your ROI on the vaunted IT system - are you there yet? You need an industry culture and an industry style focus - once we see that and its results, you will find that you don't need anywhere near the stuff you think you do - and this is assuming that you are not trying to pad the asset base to maximize regulatory returns to your new shareholders - big assumption.
- Invest now (in the north!), where there has been no investment in decades. we are at the end of long, inefficient lines at [location] and [location]. we were forced to invest in a transmission line in red lake b/c hydro was reluctant to do so.
- Its unfortunate the state of power in Ontario. Hydro One should reflect on their performance vs other provinces and states. What are we doing wrong when it costs so much to produce power vs other areas?
- Would prefer option on invest now, but the cost may be too high, so spreading costs may be better

Q What does it depend on?
[asked of those who answered "it depends" to previous question]

- Not knowing exactly what the investments are made to achieve/address and their impact/cost this question is difficult to answer in general.
- Rate increases vs internal savings. Demonstrating internal efficiencies and cost cutting (salaries) eases the impact of continuous rate increases.
- Getting what you really need right (nowhere close to that yet), getting your operating costs in line (lot's to do there), what your financing charges are compared to ours (we have to borrow to pay for you guys, and your rates are likely lower than ours), setting priorities that provide a level of priority for economic health of your jurisdiction vs convenience.

Reliability (1)

Q When you are talking about transmission reliability, what does that mean to your organization?
[asked of all respondents, n=103]

LDCs

- Our customers are nearly 100% depended on supply we receive from Hydro One. Therefore reliability has a direct impact on our customers.
- Reliability of service to our delivery points
- have the "clean" transmission supply continually available
- Transparent communication on system operations that create power quality or outage events in the distribution system.
- Sustained outage of transmission circuits resulting in loss of load at WNH delivery points. Recent experience is these events seem to happen more frequently on double circuit transmission lines when one line is already out for planned maintenance.
- We only have the one circuit in our community so the reliabiliyt of that circuit is quite important to our township. For example, winter months where we have lost power for 3 days in the middle of winter.
- Availability of power and or service
- A system that is not down due equipment breakdowns
- adequate and sufficient power. Power available when you need it in a safe manner
- Consistent supply of electricity and fast response to interruptions.
- Keeping the lights on
- Uninterrupted supply. Their Tx reliability is very good!
- this is extremely important as an LDC our customers count on us to deliver a safe a reliable system and we expect the same form our provider
- No loss of supply events greater than x for longer than y - x and y are terms I am certain will mean something different to most. It is also accepting a go forward view as to the level of managed risks we are being exposed to - we should not accept a level of risk of outage greater than Z when planning and operating the system
- Reliability is a measure of how often the system is available for use operating
- Reliability being the dependability of the service and being able to count on the reliability of power to be available without itneruptions. HIghly reliable versus unreliable.
- No outages
- It is presence of in specification voltage levels and adequate current availability.
- Reliability means minimization of incidents where power is interrupted for more than a couple seconds. It is closely related to power quality and is often used interchangeably by customers that are sensitive to power quality issues.
- Reliability is key in providing service to our end customers. Ensuring safe reliable electricity is imperative.
- duration and frequency of loss of supply incidents that affect our customer base.
- Essentially reliability it is the time the power is available. Being a dual element system the reliability is generally excellent. However, since a transmission outage can be a major event, the risk of an outage due to a forced or planned outage of one of the elements is also a consideration.
- For our organization, reliability would refer to the availability of at least one of the two supplies to the station supplying our feeders. For single source stations, the lines are maintained to provide alternate supply routes via switching. Our customers have growing expectations for availability of power and we in turn rely on the Hydro One transmission system to allow us to service our customers.
- Power available 24/7 at the correct voltages and with no curtailments of supply
- Frequency and duration of power interruptions.
- relaibility of supply - availability of power

Reliability (2)

Q When you are talking about transmission reliability, what does that mean to your organization?
[asked of all respondents, n=103]

End Users

- No unplanned extended outages
- no outages and constant electricity quality
- 1) No interruptions2) Having a ""plan B"" - redundancy built into the system
- Continuous, uninterrupted and good quality supply of power to Customer
- Reduction of unplanned outages
- 0% of unplanned downtime with respect to electrical supply. Power is a significant input to the operations, safety, and protection of the environment. Unplanned outages have high consequences.
- Continuation of services, minimizing lost time due to equip./line failures
- I translate it to availability. I don't expect 100 % it can be defined. No outages lasting longer than 8 hours except with one catastrophic outage once every 3 years lasting no longer that 3 days. 95 % of days with no interuptions. That is what I would expect.
- Un-interrupted power supply.
- No unplanned outages...
- Zero interruptions, very low number of unplanned events such as loss of redundancy and power quality incidents (particularly voltage sags).
- 100 % power availability and 100% quality
- Reliability = Uptime or ability to fuction
- No power interruption at all times. Our facility is 24x 7 service industry and continously power is a key to all the safe operation of the plant and to keep the production to meet the customer demand
- No power interuptions means higher productivity.
- Power available to run our pumps on a continuous, uninterrupted basis.
- A reliable transmission is delivering electrify to the distribution point in a form (within reasonable tolerance) that doesn't cause any disruption to our plant production process.
- Mean a lot. Any interruptions and loss of power cost us lot off money and potentially lose a customers
- We are a 24/365 [removed for privacy] operation that is energy intensive and trade exposed. Power outages have a large negative effect on the bottom line.
- Uninterrupted supply of electricity to meet the utilization of our operations.
- Consistency in product and service supply, with minimal interruptions or periods of reduced service quality.
- power outages cause major issues on campus, research experiments are compromised, failure of electronic equipment increases from outages or blips. There is a financial cost to each recovery from an outage, at times in the tens of thousands
- Number of times each year we experience a partial or total plant trip due to the transmission system.

[CONTINUED ON NEXT PAGE]

Reliability (3)

Q When you are talking about transmission reliability, what does that mean to your organization?
[asked of all respondents, n=103]

End Users

- Percent of the time sufficient power is available to operate our facility.
- Consistent power supply, little to no unplanned outages. Planned outages are also part of reliability, so we as the customer can plan as well.
- 115kv power available 365 days 24hrs a year
- zero interruptions which force an unplanned shutdown of our facility.
- No unplanned outages and consistent power quality. (Ie no impact to production).
- Power stays on in such a fashion that it does not kick out and/or burn out instrumentation, VFD's, and other (typically expensive and vital) equipment
- Steady operations, with long MTBF.
- Very few unplanned outages
- That the Light is on when I turn on the switch
- power available around the clock.
- Consistency of supply.
- A measurement of uptime
- Consistent supply of quality electricity with few if any unscheduled interruptions
- No unexpected outages or variance from agreed upon target voltage supplied to site
- Any power outage can cause a loss of production. And due to the limitation of travel can cause issues with men underground

Reliability (4)

Q When you are talking about transmission reliability, what does that mean to your organization?

[asked of all respondents, n=103]

Generators

- Providing stable and consistent energy as promised
- uptime while maintaining excellent power quality
- Minimal power interruptions.
- Power from the grid available when required and no generation interruptions
- Our ability to get power onto the grid. It's knowing of planned outages, reduction of forced outages, limiting time, length and number of outages. I think Hydro One does an excellent job of providing contingency.
- There when needed
- Maintaining the resources required to provide customers with the proper delivery of electricity.
- The ability to generate our production (electricity) and sell our product.
- Having no service interruption or fluctuation.
- The ability to generate and export power.
- Reliability means we can rely on the transmission system to be available at all times to allow our generation facilities to transmit electricity to the grid.
- Stable connection, less outage, long term operation.
- up time vs downtime
- Systems are available and trasmitting our electricity without interuption.
- As a generator it also extremely important that HONI is available to take the power and transmit it. When developing projects cooperation and schedule adherence is very important.
- Continuous supply of quality energy
- The grid is ready and available to deliver our electrons at all times, primarily during on-peak periods.
- Reliability to us is that we are able to transmit power into the H1 owned facility, as our core business is to sell power to the IESO
- Availability, minimize planed and forced outages
- Minimisation of production revenue losses
- Less down time on the grid with stable power. Very important
- No unplanned outages
- The number and duration of transmission line outages
- Proper technical operation, no unintended outages due to equipment malfunction or failure. Planning of outages taking into consideration customer impacts and full up front communications with those customers, not just a select few.
- power is flowing as required with little to no down time.
- uninterrupted power transmission
- Having a stable and reliable grid for which power can be injected as a generator.
- Ability for the grid to stay operating, including managing around foreseeable unforeseeable events for high "availability"
- It mean that the transmission system is always available.
- Electricity flows when needed and no power outages;
- Grid availability as we are a renewable energy generator and rely on the grid to sell our product.
- low outages due to equipment failure
- Reliability means the customer can understand when power will be on, and will be off - they can plan for this and understand that if Hydro One says the power will be on; it will be on. In the event of storms or other disruptions; Hydro One will move swiftly to return power from unexpected events.
- Grid reliability isssues do not impact generation from nuclear and other large generators, low risk of blackouts

Comments on Reliability

Q Is there anything else you would like to add on the topic of reliability?
[asked of all respondents, n=103]

LDCs

- Their Tx reliability is very good. Communications is more important to use the loss of supply (mind you, loss of supply rarely occurs).
- Power quality is most important to large, power quality sensitive customers while small commercial or residential customers are most concerned with the number and duration of day-to-day interruptions. Most customers have the most tolerance for outages due to major events as they can understand the reason behind the outage while the cause of day to day outages is largely invisible to most customers.
- The only choice in this survey is reducing. There is no option to maintain current levels. Being prepared to minimize the duration of an event should it happen is important.

End Users

- Major events cannot be reasonably predicted especially with global warming trends and more severe weather. The flexibility and the ability to react to the event is more important which will impact duration.
- Drag and drop does not work in my browsers.
- Consistent and reasonable Power Quality is a main element any reliable electricity supply.
- no
- Drag and drop does not work. most important reducting the number of day to day interruptions, reducing the durantion of day to day interruptions, reducing the duration of interruptions due to major events, reducing the number of interruptions due to major events, overall power quality.
- At [company] a consistent voltage supply with minimal swing from min to max is critical for our plant. It's fine to quote industry standard expectations, our expectations are higher than this.
- Unplanned outages whether day to day or major events have significant impacts on employee safety, the environment, neighbouring communities and profits. Our licence to operate is compromised.
- A one minute outage or a 30 minute outage will still cause over 2 hours of production loss.
- This question is like asking me do I prefer having my eardrum poked out or my finger nail pulled off - anything that brings our equipment down costs us a lot of lost production, lost material, and often lost instrumentation boards etc. Once we are down, whether the power comes back in 2 seconds or two hours is less important - we are often down for over a shift anyways.
- Not relevant. All equal.

Generators

- As long as we understand this is seen purely from me as a power producer. We don't rely on the grid for our internal stuff.
- On-peak periods is our main focus and need interruptions reduced or eliminated during the on-peak periods Monday thru Friday.
- Power quality is not a transmission issue and shouldn't be on the list. Frequency and duration of outages are the key. Due planning processes for planned events is critical.
- i understand we do not control the weather, goal is to reduce the impact on the utility

Investment Scenarios (1)

Q Please use this space to tell us why you placed the slider where you did
[asked of all respondents, n=103]

LDCs

- best balance of costs vs benefits
- This rate should still enable you to decrease the risk without a significant short term rate increase.
- I recognize HONI has very difficult choices to make. However, it is very difficult to support a transmission rate increase that is greater than 1.5 times CPI
- It combines all four scenarios into one with moderate rate increase, high reliability and moderature future increases.
- Ideally, the rate increase would be inflation plus some nominal percentage. However, if 3.3% results in a material decrease in service capability, this new information suggests that the next highest level of investment is appropriate, thereby putting this somewhere in between Scenarios C and D.
- decrease on reliability risk while levelling future rate increases.
- 1) Hydro One is inefficient and needs to sort out their internal processes and find greater efficiency.2) There is nothing in this plan for innovation. Why would they invest in Tx infrastructure without a plan to manage the two-way flow of electricity that distributed generation will bring in 10-15 years. The last thing anyone wants is billions of $ in distressed transmission assets.
- Low rates a priority and managed risks - information is imperfect and so the best investment is to get better data/information while you have the time to drive better investment outcomes while living within a cost affordability index. Are you getting the right bang for your investment today? That data was not made available - can you assume you will get more for the money you are investing?
- I would consider a point midway between scenario B and C, the point where risk is neither increasing or decreasing..
- Under your maintain current level you are showing a reduction in average percentage of key assets beyond normal life expectancy. how is this maintain? In addition, you are suggesting that to maintain current levels of expenditures you need a 5.1 % annual increase in rates. Why is it not at or below inflation? These various senerios don't seem to make sense when looking at the rates or risks shown
- This scenario keeps the transmission system at about the same health level as it is today and while the transmission rate increase is moderate, the overall bill impact is small and likely tolerable by most customers.
- Significant investments have been made over the last five years to allow for DG resources to be connected. My expectation is that the rate of investment can now be curtailed back some.
- The costs are a major input into these evaluations. A TS decommisioning was quoted at over $10M, transfer trip for a DG a few years ago was $180k is now being quoted at $400k, rebuilding a TS is being quoted at $38M. The choice is really C with an A rate increase.
- The system already has a health percentage of aged equipment and with the increasing reliance on the transmission system to achieve the government's environmental goals, reliability will only become more important.
- No choice made. Analysis simplistic. Need to look for alternative savings (OM&A) to offset cost of increased asset investments.
- Keep increases at inflation.

Investment Scenarios (2)

Q Please use this space to tell us why you placed the slider where you did
[asked of all respondents, n=103]

End Users

- Chose the middle, trying to find a happy medium, so that we try to fix the mess we are in efficiently and cost affective as possible. However the rate increases is to high but we can't keep delaying either creating a bigger problem for future etc
- maintaining the current level of investments will provide the planning and necessary funds for equipment is replace/upgrade as required to ensure reliability of power supply
- Good balance
- Reliability needs to improve but rate increases need to be balanced as it effects our operating costs
- To maintain a consistent cost(although increased) with a higher reliability.
- I am prepared to take on more risk as we get the cost envelop sorted out and I am not willing to accept that rates would only change from .11% to .46% between scenario's when costs to the public have been going up by double digits per year for many years. IN addition I am not prepared to accept that managing the rate of investment now will necessarily result in significantly higher future rates. The whole system has to take responsibility for the costs the public is struggling with NOW !
- Maintains the average percentage of key assets beyond expected service life constant.
- Preference would be investment close to scenario C but at lower transmission rate increase. i.e. Hydro One should look into improving its own efficiencies or finding ways to obtain the required funds to achieve scenario D or at minimum Scenario C's goals without significant increases to the transmission rates.
- The current level of reliability is acceptable therefore maintaining the status quo would seem appropriate.
- Reduces risk, reduces the number of assets beyond expected life, cost increase is high, moving to Scenario D does not reduce the risks that much more based to cost. Selecting Scenario A or B will put our distribution system at to high a risk.
- Transmission costs are already too high. More needs to be done to ensure the investment $$ are being spent wisely.
- Hydro One is unfortunately operating in one of the highest rate markets in North America. Normally higher increases could be tolerated, however with the current state of the electricity market reasonable rate increase are expected, even if it comes at the cost of degraded reliability. This is ultimately due to current and previous provincial governments however Hydro One is forced to take this under consideration.
- Internal savings and efficiencies must be considered (salaries) to minimize rate increases. Increases in the 2 to 3% range combined with internal savings should net to Scenario C. This should be the goal.
- It would appear that the infrastructure has not been maintained at the correct pace. A reduction now would jeopardize future reliability.
- Your reliability assessments are not credible - on the single circuit SAIDI you do not even know why the majority of the interruptions occurred - so how can you model accurate reliability assessments? Your question is the equivalent of asking "if I fall out of a boat, should I wait for help or try and swim for shore? Why not just climb back into the boat?" You are missing the third option. Ex: instead of flying helicopters to check lines, why not use drones whose flight controls are tied to a carrier signal on the power line itself - get creative with the regulatory guys and find a way to reduce the costs - this is what industry does ....How big a transformer can you put on a flatbed - can several (already on flat beds) be used for multi circuit reliability and in case of an emergency, pulled out to use elsewhere ..... what about a system (used in Europe) where if one phase goes out, the other two are (downstream) reconfigured to power all three lines - just with a reduced capacity, until repairs are made. etc - etc
- we're on unreliable lines so we'd like some investment in those lines under any scenario. some is more than what we've seen in recent years. with upward pressure on rates, we'd be hard pressed to call for much more reinvestment than B. I'm wondering about the capital estimates and whether or not there is any room for efficiencies within?
- Please lean on successful areas (provinces/states) that face the same pressure and show a marked improvement in Reliability and Quality and use that as a benchmark.
- Do not want to see any service supply or reliability deteriorate from the current state

Investment Scenarios (3)

Q Please use this space to tell us why you placed the slider where you did
[asked of all respondents, n=103]

Generators

- It meets many of the things and it's a subtantial capital investment, but it has a lot of things moving in the right way. Decrease in reliability risk, improvement in long-term reliability. Fairly level future rate increase.
- You should manage your business to be at or below the annual Canadian index price increase and still be reliable. Actual rates are already very high. We pay anywhere between $120-150/MW which is too high.
- Balance the annual rate increase based on risk.
- Scenario A seems the most favourable at this time; companies are very cost focus and margins are currently very tight.
- increased reliability, levelled rates
- Clever OEB type presentation Ontario in very fragile economic condition Just focus on cutting cost There is not as you imply direct correlation between cost reduction and reliability
- The reality is we have taken the cheap route and now the system needs to be upgraded and repaired. Best to pay and be done with it.
- The current situation is in part the result of a deliberate reduction in re-investment in the mid 1990's to mid 2000's which has resulted in equipment beyond service life. If reliability levels are to be maintained or improved, then a balanced and consistent approach is required.
- there is a lot of old components that need replacing already. reducing spent $'s will not enhance current performance
- We want a decrease in reliability risk and not too much increase in rates;
- I do not agree with Hydro One's premise that there should be increases in Hydro rates amongst all the options. Like any other business; Hydro One needs to improve how it runs its business; how it seeks innovative answers; how it can deliver the same or better service for less money. I fundamentally disagree with all the options above; Hydro One has to stop acting in a way that it think it is entitled to more money or else the lights go out; Hydro One needs to start thinking like all other businesses; get lean; lower costs; meet customer expectations. The people and businesses of Ontario shouldn't have to keep paying for Hydro One's excesses. Rates should be kept constant; and the service should improve for that cost moving forward.
- Best choice overall from reliability and long term cost perspective

Questions for LDCs (1)

Q Is there anything in particular you feel Hydro One can do better to help you meet your customers' needs?

[asked of all LDC respondents, n=28]

LDCs

- Improved Communication to LDC's on reliability issues
- more regular updates
- Mitigate short circuit constraints for generation connections.
- Harden the single circuit 115 kV D10H circuit that supplys Elmira TS. We have lost this supply twice in recent years during ice storm events.
- Nothing. They are doing a fine job at this point with regards to transmission
- Not really
- Invest strategically in infrastructure. Cap top 5 salaries of Hydro One staff (ie: CEO, CFO, etc.) for letting the system deteriorate to the point where it is right now.
- Increased pre-planning for joint investments with the LDCs. Improve project management to achieve project milestones on time. Better transparency of costs associated to projects requested by the LDC for Hydro One to complete.
- Improve its brand/reputation. When Hydro One "screws-up", it bring the reputation of the entire Ontario electricity sector down. This make working with my LDC's customers more difficult.
- no I currently do not have any issues especially with the people that I deal with
- Treat me like a customer - provide me with the level of data needed to manage my customers - often you will react to my customers who are mine and provide better information to them (cause of outage, expected duration, etc) than you do for me. Better collaboration between control centres - I bet you dont treat your Hydro OGCC the same way you treat other utility control centres.
- Assist with Power quality investigations.
- Better support at local level
- communication and coordination of TS work requires significant improvement
- Better planning of maintenance outage notifications. Costs need to stabilize while at the same time allow for development of new loads in rural areas at costs that are reasonable and not prohibitive. Don't try and push normal maintenance and replacement costs onto new customers.
- It would be helpful if Hydro One were able to provide more reasonable cost estimates for their work. In past years, Hydro One was know for high costs of work and had an active program to reduce their costs of doing business. That effort seems to have waned now and costs have gone back to levels that many customers feel are too high.
- LDC's and Hydro One need to be working in partnership not as competitors allowing for further cooperation and to paticipate in early consultation
- improve reliability in smaller rural communities, reduce engineering costs for distributed generation projects. reduce operating, maintenance and administrative costs as a whole and pass the saving onto the customer base.
- See the opening comments.
- Consider both the financial and reliability impact of your actions on our customers.
- regulate voltage better
- lower rates

Questions for LDCs (2)

Q Is there anything in particular you feel Hydro One can do better to serve the specific needs of First Nations and/or Métis communities?

[asked of all LDC respondents who serve First Nations and/or Metis communities, n=2]

LDCs

- No.
- The northern single circuit communities deserve more attention as they are more vulnerable in terms of supply and outage response.

Content Covered (1)

Q Was there any content missing that you would have liked to have seen included?
[asked of all respondents, n=103]

LDCs

- NO
- No mention of removing transmission constraints for distributed generation in our area
- None that can be recalled
- A section focused for the LDC to comment on joint projects.
- Innovation -- how is Hydro One being innovative?
- not at this time
- Yes - already told you your current performance on asset plans was missing, your risk management plans were missing, your productivity improvement plan to show what you get for the $ invested and how much more is expected so that I could "trade" off appropriately
- No.
- No

End Users

- More detailed breakdown of cost
- Cost reduction; show customers what you're doing to save money and find efficiency.
- Although hard to do, a break out of necessary upgrades based on affected areas of distribution, could potentially make justification higher.
- I simply don't agree with some conclusions and feel the analysis was skewed towards the higher investment options.
- It would be good to know what Hydro One is doing to improve its own efficiency in order to free up funds to cover some of the investments
- How to save in GA costs.
- None
- Overall Good Content.
- Results of benchmarking Hydro One with other North American utilities to compare fixed costs, maintenance spend, capital spend and other measures of productivity.
- What is the action plan for internal savings, efficiencies?
- Cost of service - you are an expensive service in an expensive province - if you are having trouble paying for the grid today, then how are you going to pay for it tomorrow when so many more industrial plants leave the province (and we are not investing in Ontario assets - just letting them run down to obsolescence - closures are coming).
- A breakdown of the "key assets" where the major investments are required

Content Covered (2)

Q Was there any content missing that you would have liked to have seen included?
[asked of all respondents, n=103]

Generators

- No
- No
- Some graphics may help. Circuit performance. A map of circuit performance - who is getting the best performance?
- No
- did not attend
- Graphs of last ten year cost and productivity info Benchmarking
- No
- Some metrics on resourcing required to achieve the goals, efficiency improvements.
- CIA, Connection Cost Estimate and work planning, timeline improvement
- I thought it was quite comprehensive for our purposes, but one aspect to add in for future may be interconnection process feedback.
- plan for increasing the amount renewable energy that can be connected
- I think there is an obvious outcome locked into the questions; whereby all answers involved increased funding. I think this is dishonest and lacks alignment with the people and businesses of Ontario that don't have such a luxury.

Outstanding Questions

Q Is there anything that you would still like answered?
[asked of all respondents, n=103]

LDCs

- No
- Nothing
- Not at this time
- no
- How is Hydro One going to improve productivity? What is process for managing staff / project teams in Northern Ontario?
- no
- When you are releasing the plans? Will there be any dialogue on rates and where will we get a chance to review tha comments?
- No.
- No

End Users

- Cyber security plans.
- Sufficient
- No
- See above
- How do you plan to improve reliability while decreasing costs - and if you are telling me that it can't be done, then in industry parlance "you're fired"!!

Generators

- No
- No
- No
- No
- did not attend
- Please ensure to pass on the current level and expectations of customer focus to new employees of HONI; communications is key and appreciation of the cost to customers when the grid is not available.
- NO just focus on cost reductions
- No
- i would like to be able to review and understand the Hydro outage summary. Why is it so cryptic, it should be very transparent and not require an interpreter.
- No
- Innovation and lean management of Hydro One to drive cost savings and improve performance.

Future Customer Engagements (1)

Q How would you prefer to participate in these engagements?
[asked of all respondents, n=103]

LDCs

- If my system would allow me, I would do it over the internet
- in person/email/webinars...but in person is always best
- Survey
- Proper engagement with the LDC community. We want Mayo to reach out to us (and not just to buy us). Come to the EDA and start a dialog with Ontario's LDCs.
- keep it the same as the current method works fine for me
- I would prefer the list of questions and answers fed back and how you respond differently to the critical questions and answers you are recieveing
- similarly with link again
- The survey works well. I have participated in previous in-person group sessions and found them informative as well. Perhaps a balance of alternating in-person with surveys would work.
- On line surveys are good
- I like the format, and the length.

End Users

- "1) Face-to-face feedback sessions.2) Workshops with similar industrial customers."
- Customers direct participation
- None
- Information sessions as well as surveys
- Suggest targets for productivity. H-1 should be looking to improve productivity in an effort to "live within its means" like all other businesses in Ontario - and ALL of H-1's customers - have to.
- None
- Surveys for a couple of years, face to face meetings every 3 years
- Survey is fine.
- Prefer on line surveys to telephone surveys.
- Not sure - maybe an interview would be better - tough to express yourself using words without conveying urgency or emphasis (for which the written word is not amenable - unless you are an accomplished author)
- Too much reading it was making me nod off
- survey was a good vehicle
- Asking to weigh items that are really equal seems like a waste of time.
- Same as this

Future Customer Engagements (2)

Q How would you prefer to participate in these engagements?
[asked of all respondents, n=103]

Generators

- Web based engagement
- We appreciate the opportunity to participate in the engagement and look forward to similar opportunities in the future. We believe the online survey tool is an appropriate means to do so.
- This format is fine.
- did not attend
- AS OEB has mandate over rates my input is of no value
- By on line survey
- I think the online survey is a good method.
- focus more on embedded generation with renewables
- The current method is fine.

Appendix 1.2
The Survey

Welcome to Hydro One's transmission customer engagement survey.

Why are we here?

Hydro One is starting its planning process for the 2019-2023 plan. As you may be aware, Hydro One currently has an application before the Ontario Energy Board to cover the 2017-2018 period. However, transmission systems have long planning horizons and Hydro One needs to start now to prepare the business plan for 2019-2023. For the purpose of getting your views on the outcomes and priorities that matter to you, Hydro One has used this 2017-2018 application as its starting-point. **See the "Additional Information" document for more information about Hydro One's planning process.**

Hydro One engages with its transmission customers through key account mangers, regular surveys, and various planning processes. Now, Hydro One needs to hear from you about the outcomes you care about, as well as the pace and mix of investments that you would like to see included in the plan. Your views are a key input as Hydro One sets priority outcomes in its 2019-2023 business plan and makes choices about the investments that will be included in that plan.

Your privacy will be protected.
Hydro One has engaged an independent research firm, Innovative Research Group, to document your views. All individual responses will be confidential. Your results will be combined with others in any reports. **See the "Additional Information" document to read our privacy policy.**
Throughout this survey, you will see the following: 📖
This is an indication that a word or phrase appears in the glossary at the end of this document.

WE APPRECIATE YOUR PARTICIPATION IN THIS SURVEY, AS THE RESULTS MAY IMPACT YOUR RATES AND THE EXPECTED RELIABILITY OF THE TRANSMISSION SYSTEM.

[LDCs only]
As a distributor, please respond to the questions in this survey with your customers in mind. Your feedback should be made with consideration to your customers' needs.

What we are consulting about?

The Hydro One planning process generates a number of potential capital investments📖. Some of these investments are required to comply with the various standards and regulations that apply to Hydro One's business. But many investments have a discretionary factor, at least in terms of timing.

There are three key questions about Hydro One's potential capital investments at the core of this customer engagement:

- **What outcomes should Hydro One focus on as it decides which investments come first?**
- **How should Hydro One pace its investments in the transmission system over the long run?**
- **What is the preferred balance between reliability and the amount customers are willing to pay?**

When the plan is submitted, Hydro One will share with you both a summary of what customers said in this survey and how Hydro One responded to that input.

SURVEY RESPONSE OPTIONS:
This survey takes about 20 minutes to complete.
You can complete the survey online or, if you prefer, we can schedule a one-on-one interview either in person or by phone. If you prefer a live interview, please contact Susan Oakes at (416) 642-6341 or soakes@innovativeresearch.ca to arrange a time that is convenient for you.

To ensure your comments are considered in the planning process we need your responses by June 9, 2017.

There are *Additional Information* links throughout this workbook.
The questions have been presented with the most important information one might need to make a decision. While many transmission customers are very familiar with the transmission system, there may be specific areas where additional information would help you better answer the questions. As you go through this survey, you will find links to additional information you may find useful. You may need to enable pop-ups on your browser to enable this feature. **You can also see the "Additional Information" document to download the complete background package with all the additional information if you wish.**

The most important part of this workbook is the survey questions.
Utilities are expected to develop a genuine understanding of their customers' needs and preferences and integrate them into their plans. As such, the goal of this workbook is to understand the general priorities and criteria you would like Hydro One to use when making key business decisions. While your view may not always align exactly with the available options, please select the one that is closest. If you truly aren't sure, select the "don't know" option.

You will also find comment boxes throughout the survey. The comment boxes are there to provide you with the opportunity to expand on your answer if needed.

Confidential and Forward Looking Information

CONFIDENTIAL INFORMATION

In this survey, “Hydro One” or “the Company” refers to Hydro One Networks Inc. and its affiliates, taken together as a whole.

Hydro One is providing the information contained in the following survey on a confidential basis in order to solicit your feedback on customer outcomes and potential alternate investment scenarios and their expected impact on the reliability of our transmission system. The feedback from this customer engagement will be considered when making regulatory filings. Any information concerning Hydro One provided as part of this survey should not be disclosed except as necessary within your corporation in order to provide meaningful feedback.

You should not trade in securities of Hydro One Limited or Hydro One Inc. based on any of the information contained within this survey and should not use the information for any other purpose.

In this survey, all amounts are in Canadian dollars, unless otherwise indicated. Any graphs, tables or other information in this survey demonstrating the historical performance of Hydro One are intended only to illustrate past performance and are not necessarily indicative of future performance.

Forward-Looking Information

This survey contains “forward-looking information” within the meaning of applicable Canadian securities laws. Forward-looking information in this survey is based on current expectations, estimates, forecasts and projections about Hydro One’s business and the industry in which Hydro One operates and includes beliefs of and assumptions made by management. Such statements include, but are not limited to: statements regarding expected or projected capital and development expenditures, the timing of these expenditures and the Company’s investment plans; the use of customer feedback from the engagement process and its impact on the Company’s investment plans; the impact of future investments on customer risk, reliability performance and risk, and service interruptions; statements about asset condition, the average ages of critical assets, and their future expected condition; statements about types of asset replacements and their expected associated costs; and statements about illustrative scenarios and their impact on capital spend, expected outcomes, rates, changes in risk profile according to asset class, and increased or decreased system risk impact.

Words such as “aim”, “could”, “would”, “expect”, “anticipate”, “intend”, “attempt”, “may”, “plan”, “will”, “believe”, “seek”, “estimate”, “goal”, “target”, “project” and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Hydro One does not intend, and it disclaims any obligation to update any forward-looking information, except as required by law.

The forward-looking information in this survey is based on a variety of factors and assumptions. Actual results may differ materially from those predicted by such forward-looking information. While Hydro One does not know what impact any of these differences may have, Hydro One’s business, results of operations and financial condition may be materially adversely affected if any such differences occur. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information are: the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned; the risk of public opposition to and delays or denials of requisite approvals and accommodations for the Company’s planned projects; the risk that the Company is not able to arrange sufficient cost-effective financing to fund capital expenditures; the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company’s assets or to carry out projects in a timely manner; the risk that the Company’s Board of Directors may not approve the projected expenditures; and the risk that the regulator may alter or deny approval for requested investments and recoverability in rates.

How well is Hydro One meeting your needs?

Hydro One Inc. owns and operates a 30,000 circuit 🕮 km high-voltage 🕮 transmission network that includes 306 transmission stations and transmits 98 percent of Ontario's electric capacity.

For more information about Hydro One's transmission system, the standards it must meet, its activities, and reliability statistics, See the "Additional Information" document.

Questions

1. **How satisfied are you with the overall performance of Hydro One in providing your business with electricity?**
   - ❍ Very satisfied
   - ❍ Somewhat satisfied
   - ❍ Somewhat dissatisfied
   - ❍ Very dissatisfied
   - ❍ Not sure / Don't know

2. **Is there anything in particular you feel Hydro One can do better?**
   Please fill in your response below

   - ❍ Not sure / Don't know

3. **How do you know if Hydro One is doing a good job for your business?**
   Please fill in your response below

   - ❍ Not sure / Don't know

Customer Outcomes

Hydro One has to make choices in its planning, and it needs to know what is most important to you. Hydro One is responsible to the Ontario Energy Board to show how its plans provide the cost effective delivery of outcomes that customers value. **To learn more about the customer engagement process and the Ontario Energy Board's requirements, See the "Additional Information" document.**

In reviewing its previous customer engagement research and in discussions with customer-facing Hydro One staff including its Key Account Managers, Hydro One has developed a tentative list of outcomes for your review. This survey is going to ask you if anything is missing from that list, how important each outcome is to you, and which outcomes are most important compared to the others.

This section will ask you to rate how important the outcomes are to you and to share your thoughts on how Hydro One could do better. You will also have an opportunity to add any outcomes you feel are missing.

We will be asking you about the following seven outcomes:

- Customer Service
- Environmental Stewardship
- Outage Restoration
- Power Quality
- Productivity
- Reliability
- Safety

To rate the importance of an outcome, please select a point on the slider below each description. If there are areas that you don't have an opinion on, please select the "don't know" option.

Safety

Eliminating and mitigating risk to public and employee safety in the operation of the transmission system. **For additional information on Hydro One's performance to date, See the "Additional Information" document.**

4. How important an outcome is safety?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Productivity

Implementation of new technologies and processes to enable operational efficiencies in the planning and execution of work programs aimed at reducing costs and more efficient use of resources. Hydro One understands that customers expect it to look first for internal savings before asking for any additional rates.

5. How important an outcome is productivity?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Reliability

Maintaining the uninterrupted operation of the transmission system for all customers by sustaining the existing assets, replacing assets that are in poor condition and addressing transmission system performance outliers 🕮. **For additional information on Hydro One's performance to date, See the "Additional Information" document.**

6. How important an outcome is reliability?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Outage Restoration

Provisions to ensure timely and efficient response to failures, unplanned outages 📖, or imminent risks to the transmission system to minimize customer interruption and prompt restoration to normal operating conditions.

7. How important an outcome is outage restoration?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Power Quality

Delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform 📖. Assessing customer concerns and implementing mitigation plans to address and rectify power quality issues for transmission connected customers.

8. How important an outcome is power quality?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Customer Service

Enhancements to the transmission customer experience such as outage planning and operational communications, timely estimates and project execution for transmission connected customers. **For additional information on Hydro One's performance to date, See the "Additional Information" document.**

9. How important an outcome is customer service?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Environmental Stewardship

Identifying potential risks to the environment as a result of emissions from Hydro One's own operations, and investing in mitigation strategies to ensure compliance with all applicable environmental regulations consistent with the Government of Ontario and the Government of Canada.

10. How important an outcome is environmental stewardship?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Additional Outcomes

Are there any outcomes we missed? Please use the boxes below to add them, and then the slider to rate their importance.

11a. Suggested Outcome 1:

11b. How important is this outcome to you?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

12a. Suggested Outcome 2:

12b. How important is this outcome to you?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Comments

13. Do you have any specific comments or suggestions regarding any of the seven outcomes that you just rated or any additional outcomes you added?

- Customer Service
- Environmental Stewardship
- Outage Restoration
- Power Quality
- Productivity
- Reliability
- Safety

Please fill in your response below:

Customer Outcomes

Top Priorities

While all the outcomes listed are important to many customers, planners set priorities among different outcomes. The purpose of this section is to help Hydro One set priorities as it prepares its business plan. Which priorities should they focus on first?

For a list of outcome definitions, See the "Additional Information" document

Please rank your top priorities from the list below.

Drag and drop the priorities in order, starting with the priority most important to you, followed by the second most important, then the third most important, and so on. Please try to rank all listed priorities:

Priorities	Top Priorities
Safety	
Productivity	
Reliability	
Outage Restoration	
Power Quality	
Customer Service	
Environmental Stewardship	

Comments:

Making Choices: Pace of Investment

When Hydro One replaces equipment in declining health, it has some flexibility in its pacing. **For more information on the health of Hydro One's assets, See the "Additional Information" document**

We would like to understand your general views on the appropriate pacing of Hydro One's investments over the next 15 – 20 years. Hydro One can front load its capital investments, it can spread them evenly over time, or it can delay its investments.

Front-loading investments would provide some benefits in terms of more connection capacity 🕮, decreased equipment failures, increased reliability, and improved productivity and quality. This would mean higher rate increases now but lower rate increases in the future.

Spreading evenly over time means some benefits are delayed but some long term savings are secured and it is more efficient in terms of staffing. Rate increases would increase at a stable level. Asset deployment costs would likely be lower using this more stable pacing philosophy.

Given the current health and demographics of the system, Hydro One can delay investments further until declining equipment conditions threaten Hydro One's ability to meet power reliability requirements. Reliability would still meet minimum standards but customers would likely experience more interruptions 🕮 than today. Rates increases would be relatively low for several years but increase at a steeper rate in the future.

Bearing in mind the trade off between immediate rate impact, long term rate impacts and system benefits, which approach best reflects how you feel Hydro One should pace the work required to renew the system over the next 15-20 years?

- ❍ Invest now, higher rates in short term, lower increases in future
- ❍ Spread investments out, stable rate increases
- ❍ Delay investments, lower rates in short term, higher increases in future
- ❍ It depends
- ❍ Not sure / Don't know

Why do you prefer the scenario you chose over the other two scenarios?

What does it depend on?

Reliability

We are now going to move on to the topic of reliability. The term “reliability” means different things to different people, so before we move on, please describe what reliability means to your organization.

When you are talking about transmission reliability, what does that mean to your organization?

Making Choices: Reliability

Reliability has a specific meaning in electricity, but often when customers talk about reliability, they are also talking about power quality (defined as delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform). Below is a list of five items that are often included when people talk about reliability. In addition to power quality, when people raise concerns about interruptions they often draw a distinction between interruptions that are experienced during normal day-to-day operations versus interruptions that occur during major events such as severe storms.

Please rank the following reliability items in order of which are most important to your organization.
Drag and drop the items in order, starting with the item most important to you, followed by the second most important, then the third most important, and so on. Please try to rank all items:

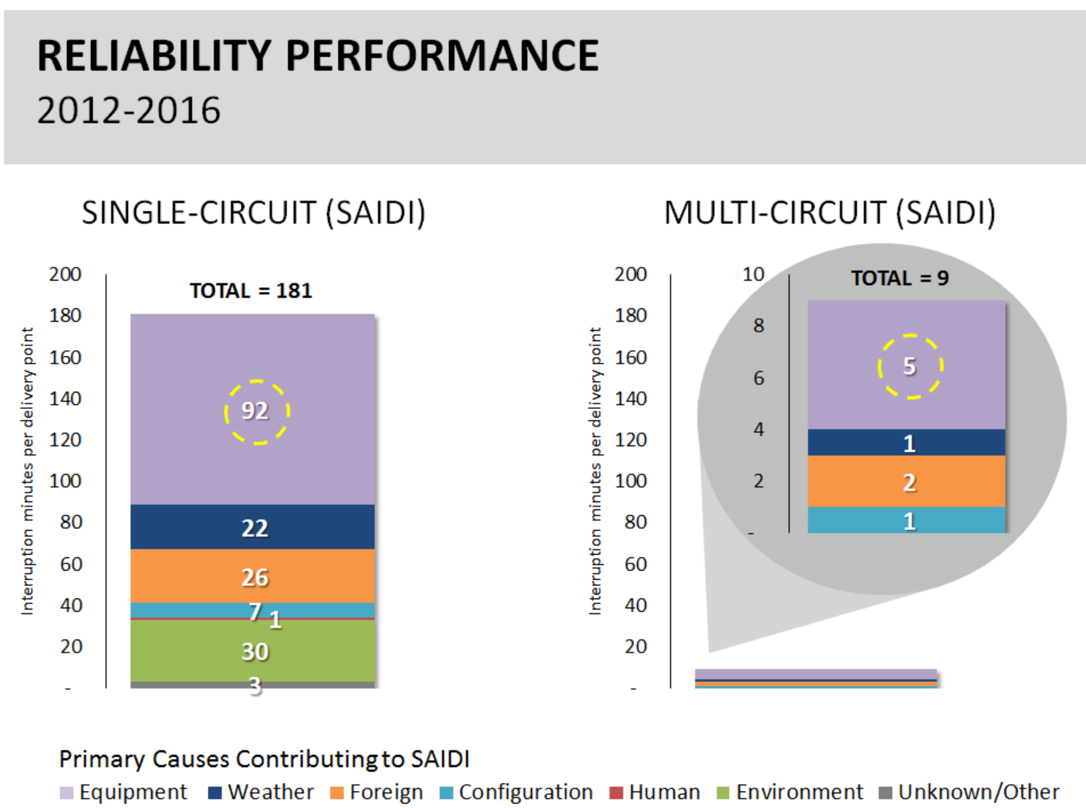
Reliability Items	Importance
Reducing the number of day-to-day interruptions	
Reducing the number of interruptions due to major events	
Reducing the duration of day-to-day interruptions	
Reducing the duration of interruptions due to major events	
Overall power quality	

Comments: Is there anything else you would like to add on the topic of reliability?

Making Choices: Reliability Trade-Offs

Understanding reliability is important when assessing the trade-offs facing Hydro One. To help understand the impact of investment decisions on reliability, Hydro One as developed a metric called “reliability risk”. No one knows for sure when a specific piece of equipment will fail, but we do know how likely asset failure is for groups of equipment in specific conditions. This means we can project a likely risk of failure for a given pool of assets.

When it comes to transmission reliability, Hydro One has performed well compared to Canadian peers. The key strategy employed to avoid customer interruption in the transmission system is redundancy 🕮. Most of the transmission system has been built with at least one redundant circuit for every operating circuit. The chart below shows the benefit of redundancy as customers on single circuit 🕮 systems experience much more time (shown below as System Average Interruption Duration Index or SAIDI) 🕮 without power than customers on multi-circuit systems 🕮.



See the "Additional Information" document to read the definitions of these categories

Transmission Customer Engagement

Delaying capital spending will, in time, result in more and more equipment failures. While redundancy often prevents these failures from leading to customer interruptions, equipment failures will leave multi-circuit customers at risk of the single-circuit reliability experience. Reliability risk provides a leading indicator of the expected impact of allowing the condition of equipment in the transmission system to decline.

Making Choices: Illustrative Scenarios

Now we would like to take one last look at the core trade-offs Hydro One must make as it begins its business planning for 2019 to 2023:

- the balance between the level of investment and system reliability, and
- the timing of those investments.

To help understand your priorities, Hydro One has developed four illustrative scenarios. The specific priority of investment items in these scenarios is based on the priorities used in Hydro One's proposal currently before the Ontario Energy Board. While those priorities may change based on your earlier feedback, these scenarios are illustrative of the impacts of various spending levels.

In considering these scenarios, please be advised that all figures are intended as approximate, and are not intended to be relied upon as exact.

These scenarios focus on the trade-offs between the pace of investment, reliability, and future rate increases. The higher the level of investment, the lower the reliability risk 🕮, and vice-versa. As you consider these illustrative scenarios, please bear in mind that your rates can also be impacted by changes in load forecast and electricity prices. All scenarios assume an Operations, Maintenance, and Administration (OM&A) expense percentage increase that is held to less than inflation.

By preparing and providing these illustrations, Hydro One makes no representation that it will select one as its plan before the Ontario Energy Board.

Transmission Customer Engagement

Please read each scenario to understand how different investment levels impact key outcomes. You can choose one of these scenarios, a point between these scenarios or a point above or below these scenarios. There is a follow-up question that allows you to discuss the factors that you considered in making your choice. Your comments will help us better understand the outcomes you value.

These descriptions refer to "key assets" 🕮 which are conductors 🕮, circuit breakers 🕮 and transformers 🕮, as their failure is most likely to impact system reliability.

Scenario A: Limited investment

- Capital investment 🕮 focused on regulatory requirements and customer demand projects, such as new connections
- Sustainment capital 🕮 limited to replacing assets subject to imminent failure; no proactive sustainment investment
- The percentage of key assets beyond Expected Service Life 🕮 will increase from 21% in 2019 to 29% in 2023, increasing expected future investment requirements
- Total 5 year Capital Investment Plan: $1.8 B
- Average Annual Transmission Rate Increase: 1.3%

Scenario B: Decrease in current level of investment

- Capital investment 🕮 reduced compared to plan filed with the Ontario Energy Board in May 2016
- Spending on sustainment 🕮 of key assets deferred to future years
- Contains lower levels of investment in productivity and fewer strategic investments designed to mitigate future rate impacts (e.g., tower coating)
- The percentage of key assets beyond Expected Service Life 🕮 increases from 21% in 2019 to 26% in 2023, increasing expected future investment requirements and expenses
- Additional capital in Scenario B as compared to Scenario A focuses on replacing assets in poorest condition, resulting in a significant reduction in reliability risk 🕮
- Total 5 year Capital Investment Plan: $4.3 B
- Average Annual Transmission Rate Increase: 3.3%

Transmission Customer Engagement

Scenario C: Maintain current level of investment

- Extends investment plan in rate application currently before the Ontario Energy Board to 2023
- Maintains current level of sustainment capital investments affecting key assets
- Percentage of key assets beyond Expected Service Life decreases from 21% in 2019 to 19% in 2023, decreasing expected future investment requirements
- Incorporates strategic investments that mitigate future rate impacts, such as tower coating
- Total 5 year Capital Investment Plan: $6.6 B
- Average Annual Transmission Rate Increase: 5.1%

Scenario D: Increase beyond the current level of investment

This plan contains all investments in Scenario C, with addition of:

- Additional sustainment capital focused on key assets
- As a result, the percentage of key assets beyond Expected Service Life decreases from 21% in 2019 to 17% in 2023, decreasing expected future investment requirements
- While the above investments benefit all customers to some degree, this scenario also increases capital to add redundancy to worst performing single circuits in system, benefiting a very small portion of customers in a significant way
- Total 5 year Capital Investment Plan: $7.4 B
- Average Annual Transmission Rate Increase: 5.6%

Exploring Trade-offs Using Illustrative Scenarios

Below is a chart summarizing all the scenarios from the previous page and their implications. As we mentioned these examples are meant to illustrate the impacts of different levels of investment on current and future rate increases and system reliability.

You will note that the two middle scenarios, B and C, offer a relatively small change in reliability risk, but moving from B to C offers significant improvements in long-term reliability. The key difference between B and C is that B has larger future increases, while C has level future rate increases. The big differences in reliability are in scenarios A and D. Moving from A to B creates a significant decline in reliability risk. Moving from scenario C to D generates both a long term reliability benefit and targeted reliability improvements for a small group of customers.

As noted earlier, by offering these illustrative scenarios, Hydro One is not committing to any of them; their purpose is to help Hydro One understand what you as a customer value. When Hydro One makes its Ontario Energy Board filing, Hydro One will incorporate feedback received through this process, but does not commit to pursuing any one of these illustrative scenarios.

Below the chart is a slider which represents the range of potential approaches Hydro One can take. On the far left is lower investment, lower short-term rates, lower reliability, and higher anticipated future increases. On the far right is higher investment, higher short-term rates, higher reliability, and lower anticipated future increases. Please use the slider to indicate what approach you think Hydro One should take. Hydro One will use the results of this exercise as a directional indicator of the route customers want to go.

NB: The location on the slider does not correlate directly with potential rate increases. (For example, while the physical distance between scenarios B and C is the same as between C and D, the impact on reliability, rates and other outcomes is very different).

See the "Additional Information" document to view a larger and more detailed version of this table.

Illustrative Scenarios				
	A: Limited investment	**B: Decrease in current level of investment**	**C: Maintain current level of investment**	**D: Increase beyond the current level of investment**
5 Year Capital Investment 🕮	$1.8 B	$4.3 B	$6.6 B	$7.4 B
Reliability Risk🕮	Increase in risk ~30%	Increase in risk ~10%	Decrease in risk ~10%	Decrease in risk ~15%
Long-term Reliability Impact	↓	↓	↑	↑*
Average Percentage of Key Assets Beyond Expected Service Life 🕮 by end of 2023 (21% in 2019)	29%	26%	19%	17%
Impact on Future rates	Significantly higher future rate increases	Higher future rate increases	Level future rate increases.	Slightly lower future rate increases.
Average Annual Total Bill Impact – Transmission Connected Customer	0.11%	0.27%	0.42%	0.46%
Average Annual Transmission Rate Increase	1.30%	3.30%	5.10%	5.60%

* Improvement in overall long term reliability and significant performance improvement for small number of customers connected to the worst performing circuits.

Thinking of all the considerations outlined, please choose a point along the line below that you believe strikes the right balance between rates and outcomes. (Remember you can choose a point located between scenarios or directly aligned with them).

Scenario A | **Scenario B** | **Scenario C** | **Scenario D**

Lower increases now
Higher future increases
Lower reliability

○ ○ ○ ○ ○ ○ ○ ○ ○ ○ ○ ○ ○ ○ ○ ○ ○

Higher increases now
Lower future increases
Higher reliability

❍ Not sure / Don't know

Comments: Please use this space to tell us why you placed the slider where you did.

Questions for LDCs

Local distribution companies have unique needs that often differ from other transmission customers. On this page we'll explore:

Is there anything in particular you feel Hydro One can do better to help you meet your customers' needs?

- ❍ Don't know / Not sure

Does your company provide electricity to First Nations and/or Métis communities?

- ❍ Yes
- ❍ No
- ❍ Don't know / Not sure

Is there anything in particular you feel Hydro One can do better to serve the specific needs of First Nations and/or Métis communities?

- ❍ Don't know / Not sure

Were your responses to this survey informed by your own customer engagement activities for the purposes of a rate application, or by any other customer research?

- ❍ Yes
- ❍ No
- ❍ Don't know / Not sure

How did we do?

Overall Impression: What was your overall impression of the Transmission Customer Engagement?

- ❍ Very positive
- ❍ Somewhat positive
- ❍ Neither positive nor negative
- ❍ Somewhat negative
- ❍ Very negative
- ❍ Don’t know / Not sure

Volume of Information: Did Hydro One provide too much information, not enough, or just the right amount?

- ❍ Too much information
- ❍ Not enough
- ❍ Just the right amount
- ❍ Don’t know / Not sure

Content Covered: Was there any content missing that you would have liked to have seen included?

- ❍ Don’t know / Not sure

Outstanding Questions: Is there anything that you would still like answered?

- ❍ Don’t know / Not sure

Suggestions for Future Customer Engagements: How would you prefer to participate in these engagements?

- ❍ Don’t know / Not sure

If you have any additional questions or comments about Hydro One’s business plan or customer engagement, email: **Spencer.Gill@HydroOne.com.**

Next Steps

Thank you for completing the Transmission Customer Engagement. Your responses have been recorded.

Upon the conclusion of the survey, INNOVATIVE Research Group will compile the results and provide a report to Hydro One.

Hydro One will review the report as it reviews its priority-setting processes and determines the recommended level and pace of investment in its updated Transmission System Plan.

When Hydro One files the Plan in its next Ontario Energy Board application, it will share with you both a summary of what customers said in this survey, and how Hydro One responded to that input.

Thank you for your time.

Glossary

Capital Investment: Money used by a business to purchase fixed assets, such as land, machinery, or buildings.

Circuit: An electrical connection involving metallic conductors that transmits electricity between 2 points.

Circuit Breaker: A switching device for that stops or allows the flow of electricity between electrical equipment.

Conductors: A metallic wire that conducts electricity.

Connection Capacity: Hydro One's ability to add new customers and/or additional load to the transmission system.

Customer Service: Enhancements to the transmission customer experience such as outage planning and operational communications, timely estimates and project execution for transmission connected customers.

Delivery Point: The point of supply where the energy from the system is transferred to customers. This point is generally taken as the interface between utility-owned equipment and the customer-owned equipment.

Expected Service Life: The average time in years that an asset can be expected to operate under normal system conditions.

End of Life: the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences.

Frequency Deviations: Fluctuations beyond the normal operating frequency range.

High-Voltage Transmission Network: Interconnected circuits that operate at 115kV and higher voltage.

Interruption: A stop in the flow of electricity to a customer.

Key Assets: Major types of transmission assets defined as transformers, circuit breakers and conductors.

Long-Term Reliability: Reliability performance beyond the 5 year rate filing period.

Multi-Circuit Systems: Systems where power delivery points are supplied by more than one circuit.

Outage: Unavailability of electrical equipment due to disturbances, equipment maintenance, or equipment malfunction. Outages do not necessarily lead to interruptions for customers if there are backup or redundant facilities to maintain electrical supply.

Outage Restoration: Provisions to ensure timely and efficient response to failures, unplanned outages, or imminent risks to the transmission system to minimize customer interruption and prompt restoration to normal operating conditions.

Outliers: Individual assets or sets of assets whose performance is significantly different than the average performance of the system as a whole.

Power Quality: Delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform. Assessing customer concerns and implementing mitigation plans to address and rectify power quality issues for transmission connected customers.

Productivity: Implementation of new technologies and processes to enable operational efficiencies in the planning and execution of work programs aimed at reducing costs and enabling more efficient use of resources.

Redundancy: The inclusion of duplicate components to the system so that delivery points have multiple simultaneous connections. The purpose is to reduce the possibility of interruption in case of component failure.

Reliability: Maintaining the uninterrupted operation of the transmission system for all customers by sustaining the existing assets, replacing assets that are in poor condition and addressing transmission system performance outliers.

Reliability Risk: An index that provides leading directional indication of overall system reliability performance based on probabilistic risk of asset failures.

Safety: Eliminating and mitigating risk to public and employee safety in the operation of the transmission system.

Short-Term Reliability: Reliability performance within the 5 year rate filing period.

Single Circuit Systems: Delivery points that rely upon one circuit for the delivery of power. If that circuit fails then power is interrupted.

Sustainment Capital: Capital Investments made in order to maintain the current expected level of functionality and capability of system.

System Average Interruption Duration Index (SAIDI): The average outage duration for each customer served.

Transformer: An electric power equipment that changes the electricity voltage level. In Ontario, the transmission level voltage are typically transformed from 500kV to 230kV and 230kV to 115kV. To supply customers, 115kV and 230kV transmission voltages are transformed to distribution level voltages.

Transmission Stations: An electrical facility that connects a number or transmission circuits and transformers and performs a “hub” function for the flow of electricity across a region.

Transmission System Performance Outliers: Individual assets or sets of assets whose performance is significantly different than the average performance of the system as a whole.

Voltage Waveform: The shape of the 60Hz voltage curve observed at the supply point.

Appendix 1.3
Additional Information

Table of Contents

The Customer Engagement Process

Hydro One's investment plan for 2019-2023 will identify, prioritize and schedule the investments made in its system. The customer engagement process will ensure that the investment plan considers and reflects the needs and preferences of Hydro One transmission customers by achieving a balance between managing reliability risk, service and cost. This investment plan will be a key component of Hydro One's transmission rate application to the OEB in the spring of 2018. As a part of its submission to the OEB, Hydro One must demonstrate that its investment plan considers the needs and preferences of its transmission customers with regard to trade-offs between outcomes, costs and pace of investment. This approach is consistent with the OEBs Renewed Regulatory Framework.

The OEB's "**consumer-centric**" *Renewed Regulatory Framework for Electricity* (RRFE) shifts the focus from utility cost to value to customers. A key requirement the rate application process includes documenting the **active engagement** between utilities and their customers. Utilities are now required to demonstrate services are provided in a manner that responds to identified customer **preferences** and **needs**.

Below are quotes taken from the OEB's Rate Handbook outlining expectations for utilities:

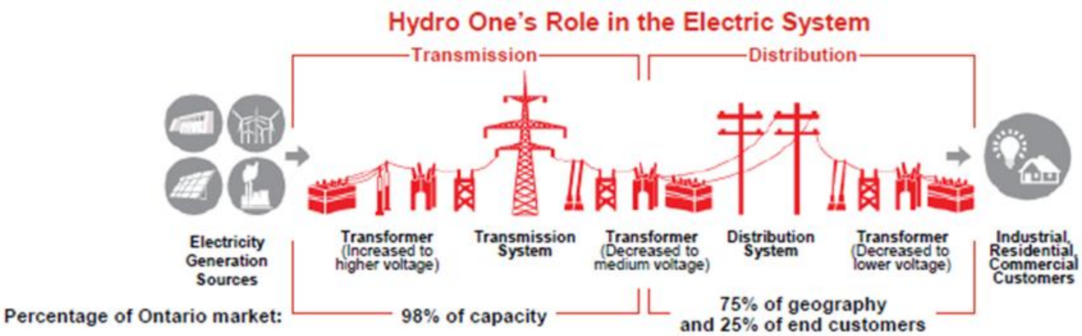
- "A utility is accountable for identifying specific outcomes valued by its customers and explaining how the utility's plans and proposed expenditures deliver those outcomes."
- "Outcomes are not activities such as the rebuilding of a pole line, but rather the qualitative expression of the utility's goals and objectives."
- "The outcomes should demonstrate the value proposition for customers and/or public policy goals."
- "Effective outcomes, in combination with the materiality thresholds, will allow the OEB to focus its assessment on results that drive value for customers."
- "The OEB has set four categories of outcomes through the RRF: customer focus, operational effectiveness, public policy responsiveness, and financial performance. Utility outcomes should link directly to one or more of these categories and be chosen to illustrate the benefits expected from key programs the utility is proposing."

All transmission-connected customers will have an opportunity to provide input that will support the development of the investment plan. Customers can provide their input by completing this online survey, or they may request an interview to be conducted in-person or by telephone.

Hydro One System Overview

Hydro One owns and operates an over 30,000 circuit km high-voltage transmission network, including 306 transmission stations, transmitting 98 percent of Ontario's electric capacity based upon revenue approved by the OEB, and an approximately 123,000 circuit km low voltage distribution network. It serves 75 percent of the geography of the province and more than 1.3 million residential and business customers.

Hydro One transmits high-voltage electricity from nuclear, hydroelectric, natural gas, wind and solar generation sources to local distribution companies and to directly connected industrial customers across Ontario.



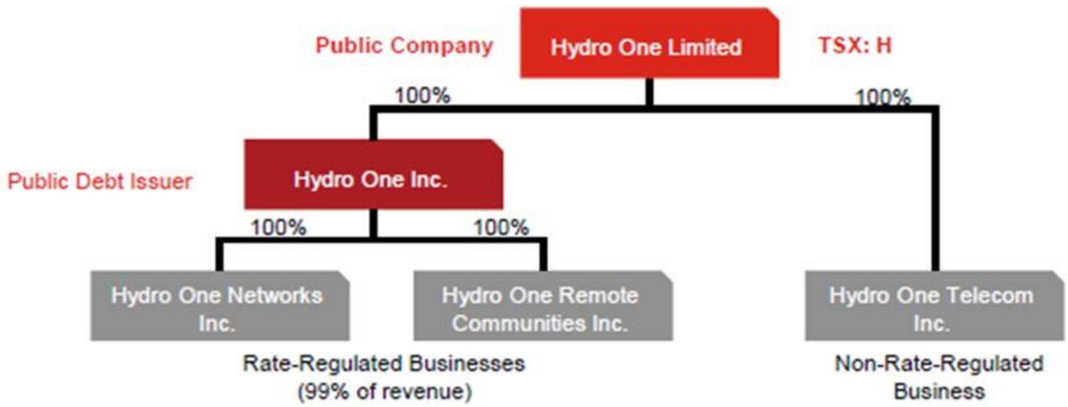
Hydro One's transmission assets can be divided into three main categories:

- Transmission stations: Used for the delivery of power, voltage transformation and switching, the stations serve as connection points for both customers and generators.
- Transmission lines: Bulk transmission lines deliver power from generating stations or connections to receiving terminal stations. Area supply lines take power from the network and transmit it to customer supply transmission stations at customer load centres.
- Network operations: The Ontario Grid Control Centre manages all of Hydro One's transmission and sub-transmission operations through a network of control, monitoring and communications equipment.

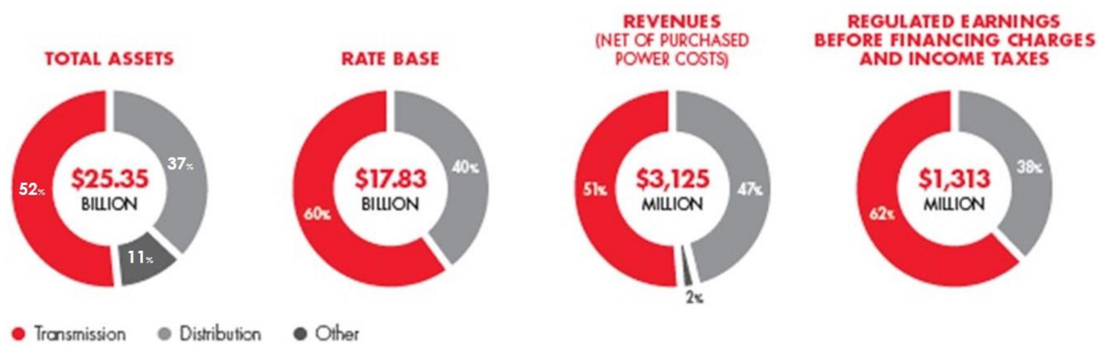
Hydro One's transmission business serves 44 Local Distribution Company (LDC) customer accounts, 87 large directly connected industrial customer accounts, and 126 generator customer accounts.

The assets in the Hydro One transmission system alone represent about $13 billion in net book value. Hydro One Limited became a public company coincident with its initial public offering in November 2015, and its common shares are listed on the Toronto Stock Exchange (TSX: H).

Hydro One's ownership structure:



Hydro One Limited's Financial Details:



Regulatory Stakeholders

Hydro One must meet the compliance requirements of six regulatory stakeholders: the Ontario Ministry of Energy, the Ontario Energy Board (OEB), the Independent Electricity System Operator (IESO), the National Energy Board, the North American Electric Reliability Corporation (NERC), and the Northeast Power Coordinating Council.

Organization	Who / What
Ontario	**Who:** Provincial Government, Ministry of Energy **What:** Policy, legislation, regulations
Ontario	**Who:** Ontario Energy Board (OEB) **What:** Independent electric utility price and service quality regulation
ieso Power to Ontario. On Demand.	**Who:** Independent Electricity System Operator **What:** Wholesale power market rules, intermediary, North American reliability standards
Canada	**Who:** National Energy Board **What:** Federal regulator, international power lines and substations
NERC North American Electric Reliability Corporation	**Who:** North American Electric Reliability Corporation **What:** Continent-wide bulk power reliability standards, certification, monitoring
Northeast Power Coordinating Council	**Who:** Northeast Power Coordinating Council **What:** Northeastern North American grid reliability, standards, compliance

Hydro One's Investment Planning Process

Hydro One must decide what comes first among specific investments. While Hydro One operates within standards that are dictated by various regulators, including the Ontario Energy Board and the North American Electric Reliability Corporation (NERC), Hydro One still has a range of choices in setting priorities among investments.

During Hydro One's planning process, candidate investments are identified by Hydro One's engineers and business planners. They take a variety of factors into account including asset needs, compliance, customer requests, regional needs, productivity and safety.

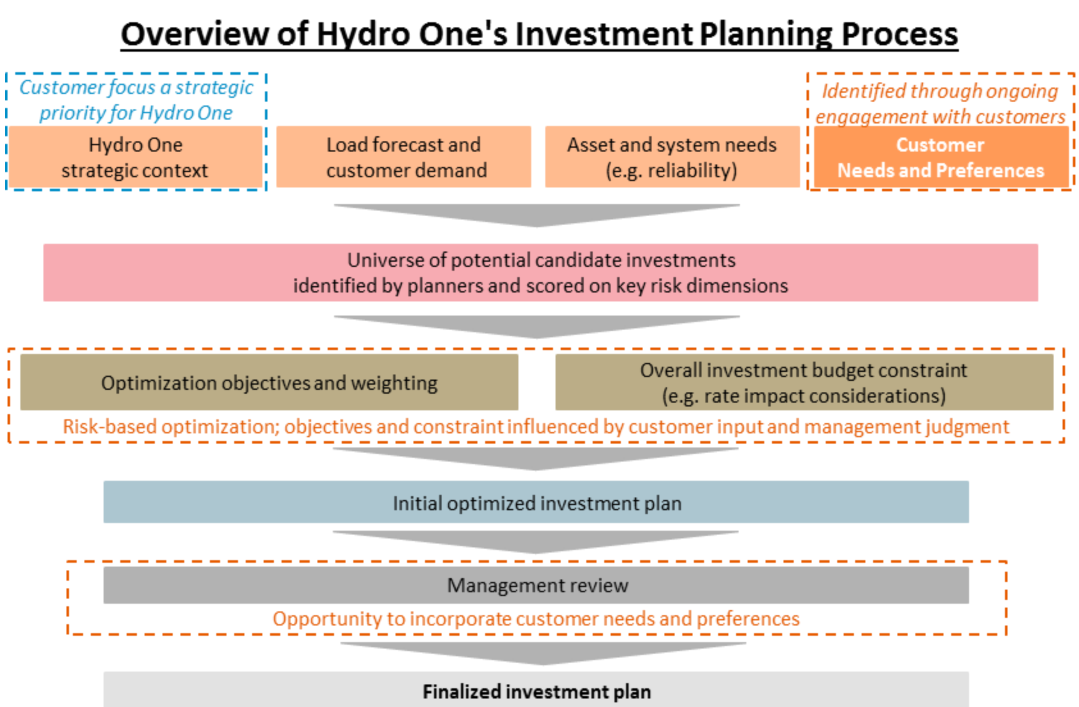
When submitted, each potential investment is scored according to a number of key criteria including the outcomes reviewed with you in this survey.

The total pool of candidate investments is then prioritized using an optimization tool that evaluates the scores assigned to all investments and compiled in to an initial investment plan.

This initial plan is then reviewed by management who evaluate the outcome of the optimization tool to ensure the plan is appropriately addressing the needs of Hydro One's assets along with the needs and preferences identified by Hydro One's customers, including the impact on rates.

Any concerns identified by this review are then incorporated in to the final plan that is approved for execution. The investment planning process is illustrated below.

Hydro One's has invested $4.3B in capital for its transmission system over the past 5 years (2012-2016).



How Hydro One's Rates Are Set

Hydro One is a rate-regulated company. Hydro One must apply to the Ontario Energy Board (OEB) for approval of its revenue requirement and the rates it charges customers. Rates are designed such that Hydro One recovers the costs allowed by the OEB and also allow Hydro One to earn a formula-based annual rate of return on its equity invested in the regulated businesses. This allowed Return on Equity is set by the OEB by applying a specified equity risk premium to forecasted interest rates on long-term bonds.

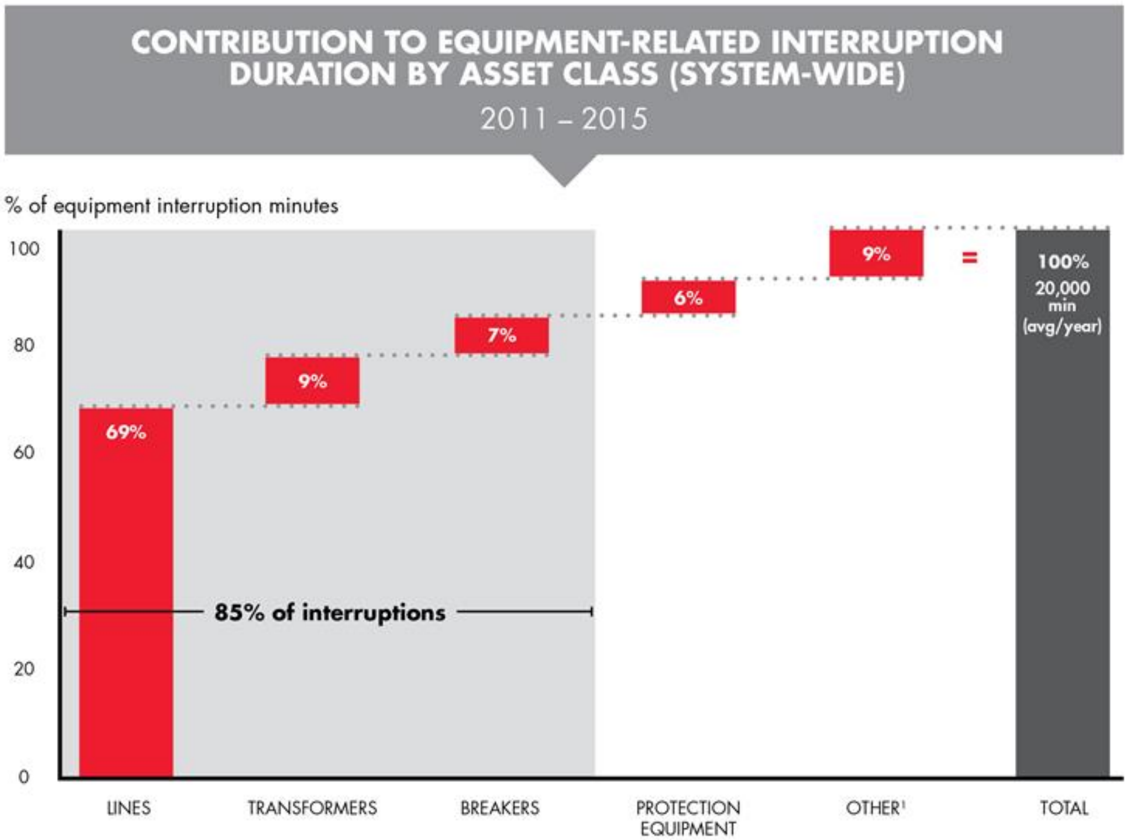
The table below summarizes the OEB-approved Transmission revenue requirement and the associated change over the prior year's revenue requirement for the 2012-2016 period.

	2012	2013	2014	2015	2016	5 Year Average
Revenue Requirement	1,418.4	1,437.7	1,535.3	1,527.2	1,567.6	
Change YoY (%)	5.1%	1.3%	6.4%	-0.5%	2.6%	3.0%

Hydro One System's Asset Health

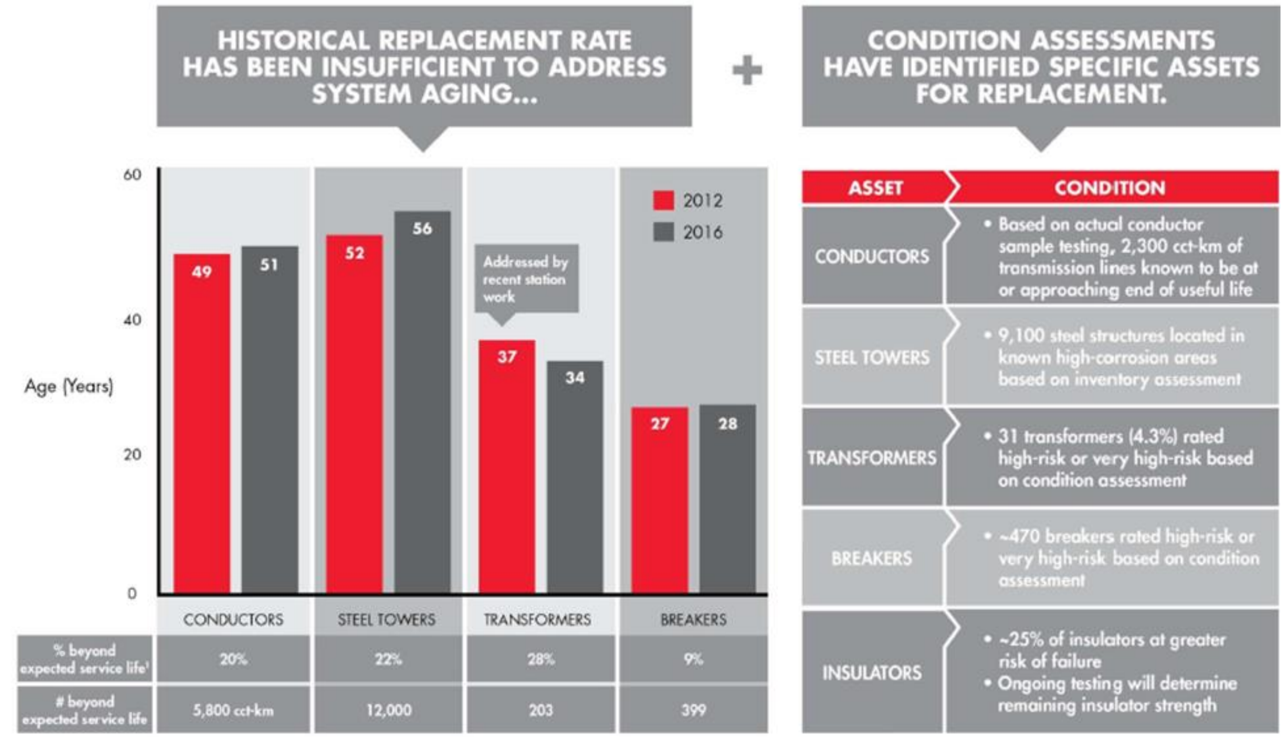
As the system ages, so do critical assets, resulting in equipment failures and sometimes in power interruptions.

While transmission lines are the primary cause of equipment-related interruptions, transmission lines, transformers and breakers combined accounted for 85% of system interruptions between 2011 and 2015.



1. Other includes switches, instrument transformers, surge arrestors, system auxiliaries

As of 2016, at least one-in-five conductors (19%), steel towers (22%) and transformers (28%) are beyond their expected service life. This translates into 5,800 circuit-kilometers of lines, 12,000 steel towers and 203 transformers. Many of these assets are already planned for replacement, but other assets continue to age beyond their expected service life.



1. The average time in years that an asset can be expected to operate under normal system conditions.

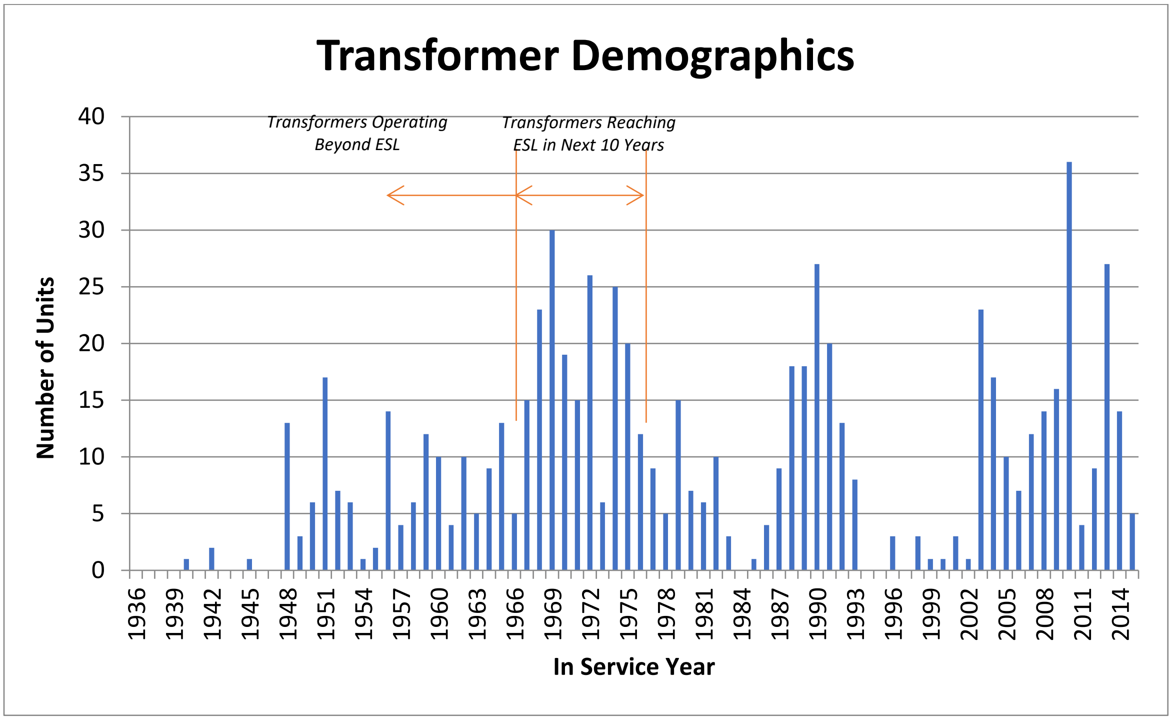
Asset Demographics

Hydro One only replaces assets that are in poor condition. The condition is determined through inspection and testing. However, a driving factor of equipment condition is age and equipment is more likely to require replacement as it ages.

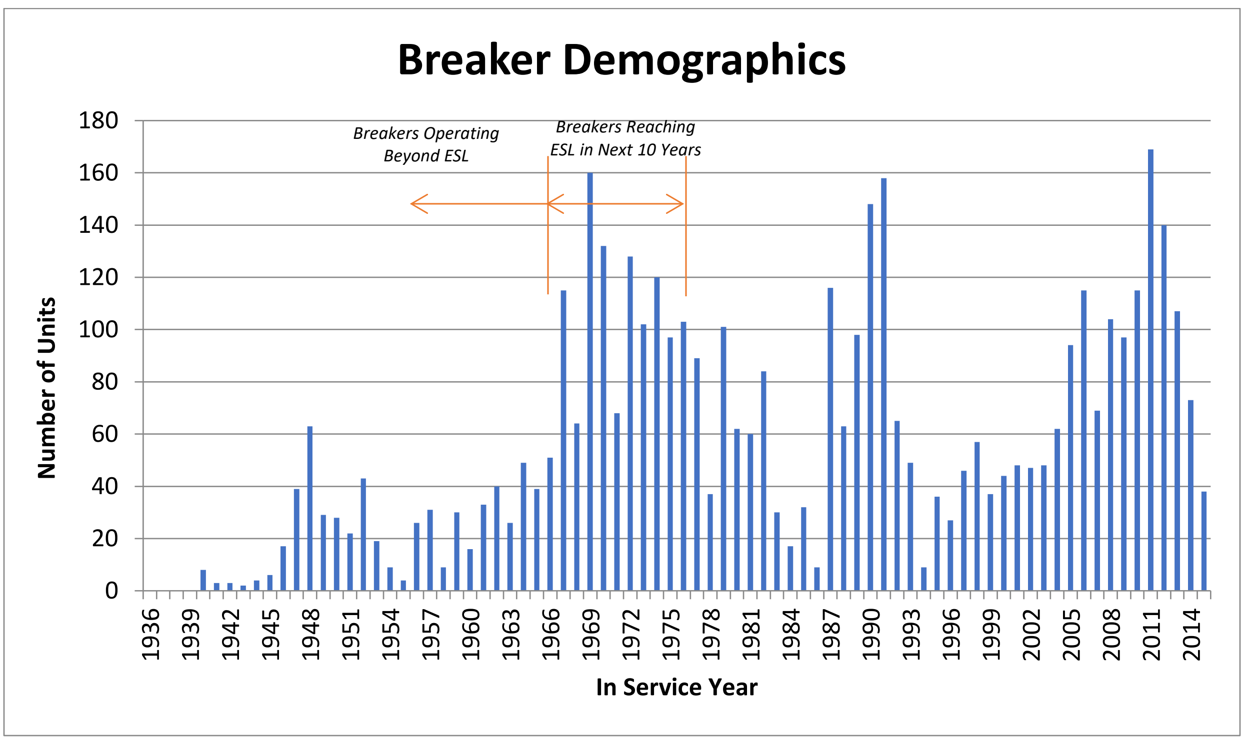
The figures below show the number of units of each key asset (transformers, breakers and conductors) that has been put in to service since the 1930s. The figures show that a large number of key assets were put in to service between the mid-60s through to the mid-70s. In the next 10 years, those assets, representing a significant portion of Hydro One's total assets, will likely require replacement.

A sizable portion of each critical asset class is operating beyond expected service life.

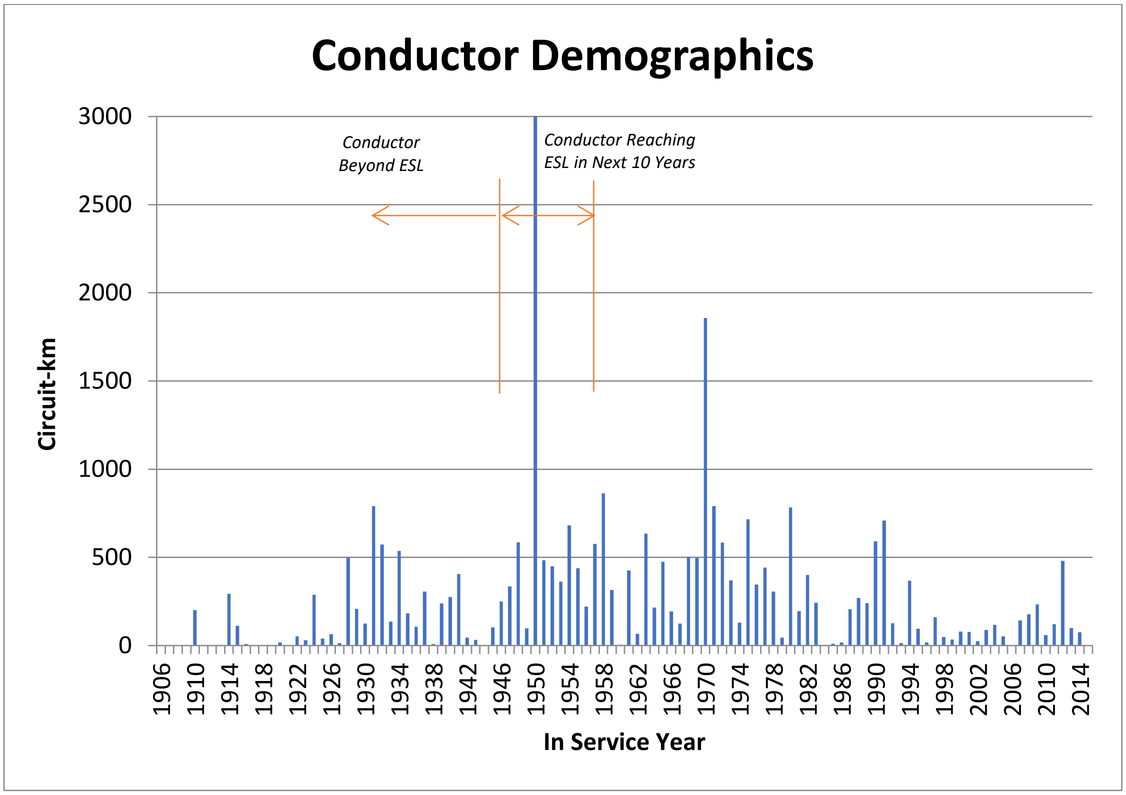
Specifically, 28% of transformers, 9% of breakers and 19% of conductors are currently operating beyond their normal expected service lives.



Transformer Demographics
Transformers Operating Beyond ESL
Transformers Reaching ESL in Next 10 Years
Number of Units
In Service Year



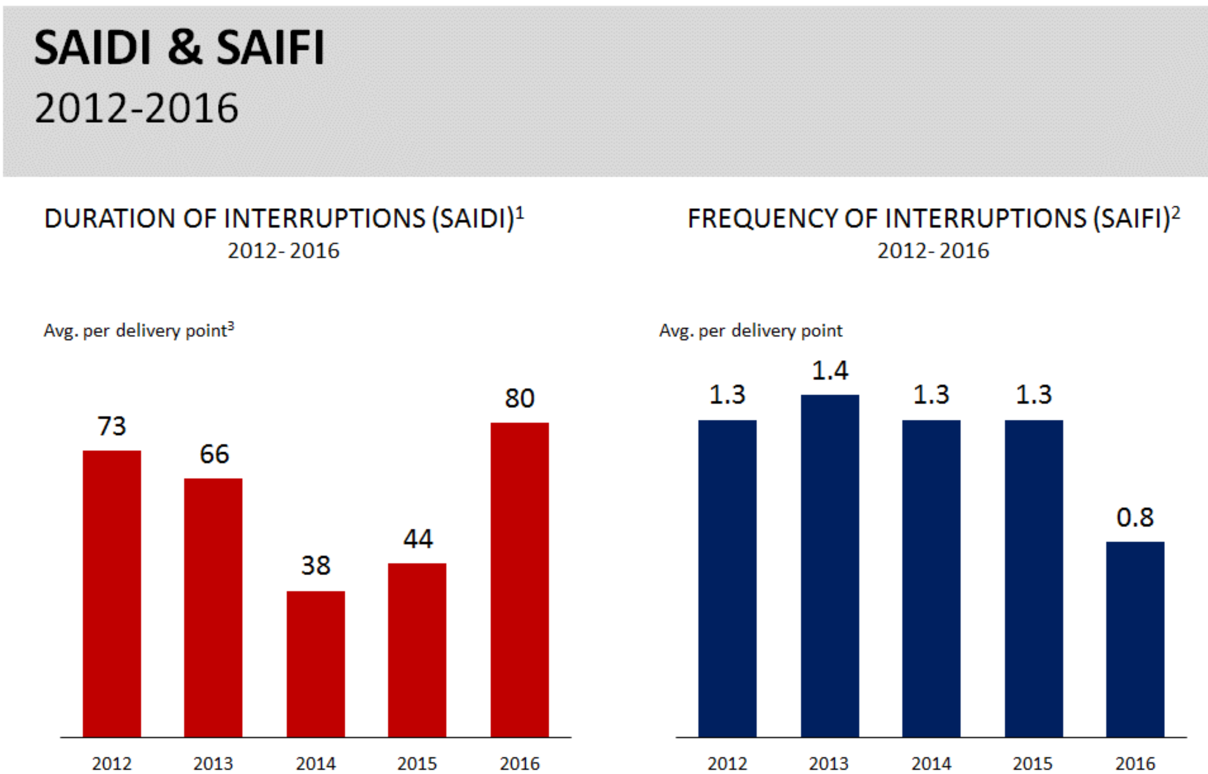
Breaker Demographics
Breakers Operating Beyond ESL
Breakers Reaching ESL in Next 10 Years
Number of Units
In Service Year


Conductor Demographics
Conductor Beyond ESL
Conductor Reaching ESL in Next 10 Years
Circuit-km
3000
2500
2000
1500
1000
500
0
1906
1910
1914
1918
1922
1926
1930
1934
1938
1942
1946
1950
1954
1958
1962
1966
1970
1974
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014
In Service Year

Reliability

Service reliability is typically measured by the average number, or frequency, of interruptions (SAIFI) and by the average duration of interruptions (SAIFI). The figures below show Hydro One's reliability performance from 2012-2016. The number of interruptions (SAIDI) was relatively stable over that period, with an improvement in 2016. The average length of interruptions showed some variability over the last five years but appears to be trending upwards in recent years.

When it comes to Transmission reliability, Hydro One has performed well compared to its Canadian peers.



Note: Includes both sustained and momentary interruptions. Excludes planned interruptions and interruptions due to customer activity. Excludes 2013 GTA flood (extreme Force Majeure event - a natural consequence of external forces that are beyond reasonable control).
1. System Average Interruption Duration Index
2. System Average Interruption Frequency Index
3. Interface between the Hydro One transmission system and its load customers. Delivery points consist of: (a) all Hydro One owned step-down transformer stations' low-voltage buses, and (b) stations owned by end-use transmission customers, including LDCs and other transmitters operating at 115kV or higher.

Reliability: Issues Driving Performance

A significant driver of the reliability performance experienced by a customer is whether or not that customer is connected to a circuit with redundancy. Customers on a circuit without redundancy experience 10x the average length of outages as those that are connected to delivery point with redundancy. About 30% of Hydro One's delivery points do not have redundancy.

Aside from redundancy, equipment performance is the largest controllable factor when it comes to system reliability, contributing 42% of system *interruption*[1] minutes. Asset continue to age (e.g., 19% of conductors are now beyond *expected service life*[2] of 70 years) increasing the number of equipment related reliability issues.

Condition assessments have identified critical replacement needs, for example:

• 2,300 cct-km of conductors identified for priority replacement due to being at or near end of useful life[3].

• 9,100 steel towers at heightened failure risk due to depletion of their corrosion protection layer.

Hydro One continues to take action to mitigate reliability risk by:

• Managing equipment performance through robust, condition-based asset replacement programs.

• Reducing customer exposure to single-supply through improved planning and work processes.

1. Outages on the transmission system that interrupt the supply of energy to transmission customers.
2. The average time in years that an asset can be expected to operate under normal system conditions.
3. As asset-specific determination based on an asset's condition, criticality, performance, demographics, utilization and economics.

Reliability Risk Model

System reliability is often measured by the frequency and duration of power interruptions. These are historical measures or lagging indicators of performance because they are indicators of past asset investment decisions. While we can measure the historical contribution of equipment failures to system reliability, not every equipment failure leads to an interruption due to the redundancy of Hydro One's system. As a result, Hydro One cannot predict the impact of investments in equipment on SAIFI and SAIDI for the parts of its system that benefit from redundancy.

Reliability risk is a forward looking or leading indicator of system reliability performance. It is calculated using a model which forecasts the risk or probability of asset failure (or needed replacement), based on the historical relationship between asset age and retirement.

It is an outcome measure used to indicate the potential improvement or decline in system reliability as the result of an investment plan. This measure also serves as a directional indicator to inform the appropriate level of pacing of sustainment investments to avoid future decline in reliability. The reliability model is not used to identify specific asset needs and investments. Hydro One chooses the assets it replaces based on detailed assessments of their actual condition.

Delaying capital spending will, in time, result in more and more equipment outages. While redundancy ensures these outages do not immediately lead to customer interruptions, the outages will leave multi-circuit customers at risk of experiencing single-circuit reliability. Reliability risk helps to capture the expected risk customers face under these conditions.

Primary Causes Contributing to SAIDI

Configuration: Interruptions due to system configuration issues where there may have been no direct transmission system equipment outage involved. This includes, loss of system issues originating in adjoining systems including other utilities and customers.

Environment: Interruptions due to adverse environment condition that existed at the time of the outage including pollution, humidity, flooding, and smoke.

Equipment: Interruptions due to defective equipment that has suffered deterioration, faulty design or materials, or lack of maintenance.

Foreign: Interruptions caused by incursions by articles or events that would not normally part of the electricity system. These include such things as vandalism, animals, solar induction, and aircraft.

Human: Interruptions caused by human error including incorrect use of equipment, incorrect documentation or labelling leading to misoperation, faulty settings, damage caused by employees or contractors during a work activity.

Weather: Interruptions caused by adverse weather conditions such as lightning, freezing rain or hail, high winds, and extreme temperature.

Outcome Definitions

Customer Service

Enhancements to the transmission customer experience such as outage planning and operational communications, timely estimates and project execution for transmission connected customers.

Environmental Stewardship

Identifying potential risks to the environment as a result of emissions from Hydro One's own operations, and investing in mitigation strategies to ensure compliance with all applicable environmental regulations consistent with the Government of Ontario and the Government of Canada.

Outage Restoration

Provisions to ensure timely and efficient response to failures, unplanned outages, or imminent risks to the transmission system to minimize customer interruption and prompt restoration to normal operating conditions.

Power Quality

Delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform. Assessing customer concerns and working together to implement mitigation plans to address and rectify power quality issues for transmission connected customers.

Productivity

Hydro One understands that customers expect it to look first for internal savings before asking customers to pay through increased rates. Implementation of new technologies and processes to enable operational efficiencies in the planning and execution of work programs aimed at reducing costs and more efficient use of resources.

Reliability

Maintaining the uninterrupted operation of the transmission system for all customers by sustaining the existing assets, replacing assets that are in poor condition and addressing transmission system performance outliers.

Safety

Eliminating and mitigating risk to public and employee safety in the operation of the transmission system.

Customer Outcomes: Performance

Reliability

Reliability performance is typically measured by the average number of outages experienced by its customers (SAIFI) and the average length of outages (SAIDI). Hydro One's SAIDI and SAIFI performance has been relatively steady of the 2012-2016 period, as shown in the Reliability section of this background material.

Safety

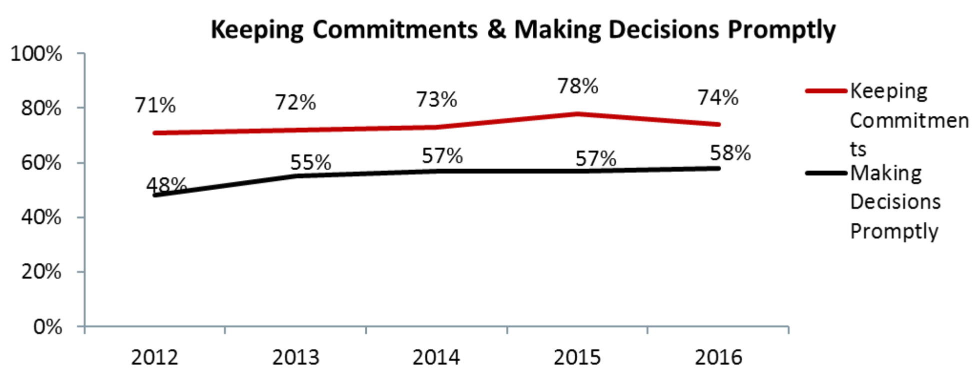
Public and employee safety are one of Hydro One's key strategic objectives. Hydro One's ultimate goal is strive towards zero safety-related incidents. The table below shows the number of serious work-related injuries/illnesses per 200,000 hours worked that have occurred from 2012-2016 along with the targets set by Hydro One. As shown in the table Hydro One has been outperforming its targets over the last five years.

Year	2012	2013	2014	2015	2016
Actual	2.3	2.5	1.8	1.7	1.1
Target	2.2	1.9	1.9	1.7	1.6

Customer Service

Every year, Hydro One conducts a survey of its large transmission customers. Among other things, Hydro One asks it's customers whether they feel Hydro One keeps its commitments to them and whether they feel Hydro One's staff makes decision promptly.

Results from 2012-2016 are shown below. The number of customers that believe Hydro One staff makes decisions promptly has increased by 10% over that period. The number of customers that believe Hydro One staff keeps its commitments has been consistent over that same period. Hydro One is committed to being more customer-focused and improving its customer service.



Detailed Scenario Summary

	Illustrative Scenarios			
	A: Limited investment	**B: Decrease in current level of investment**	**C: Maintain current level of investment**	**D: Increase beyond the current level of investment**
5 Year Capital Investment	$1.8 B	$4.3 B	$6.6 B	$7.4 B
Reliability Risk	Increase in risk ~30%	Increase in risk ~10%	Decrease in risk ~10%	Decrease in risk ~15%
Long-term Reliability Impact	↓	↓	↑	↑*
Average Percentage of Key Assets Beyond Expected Service Life by end of 2023 (21% in 2019)	29%	26%	19%	17%
Number of Key Assets With a High Probability of Failure by end 2023 †				
Transformers (12 in 2019)	14	12	9	9
Breakers (121 in 2019)	174	144	125	121
Conductors (329 circuit-km in 2019)	419 circuit-km	362 circuit-km	285 circuit-km	273 circuit-km
Impact on Future rates	Significantly higher future rate increases	Higher future rate increases	Level future rate increases.	Slightly lower future rate increases.
Average Annual Total Bill Impact – Distribution Connected Customer	0.09%	0.23%	0.35%	0.38%
Average Annual Total Bill Impact – Transmission Connected Customer	0.11%	0.27%	0.42%	0.46%
Average Annual Transmission Rate Increase	1.30%	3.30%	5.10%	5.60%

* Improvement in overall long term reliability and significant performance improvement for small number of customers connected to the worst performing circuits

† As predicted by the reliability risk model. Hydro One only replaces assets in end of life condition, as determined by detailed asset condition assessments.

NOTE: Transmission charges assumed to represent 8.3% of total bill for Transmission connected customers and 6.8% for Distribution Connected customers.

Glossary

Capital Investment: Money used by a business to purchase fixed assets, such as land, machinery, or buildings.

Circuit: An electrical connection involving metallic conductors that transmits electricity between 2 points.

Circuit Breaker: A switching device for that stops or allows the flow of electricity between electrical equipment.

Conductors: A metallic wire that conducts electricity.

Connection Capacity: Hydro One's ability to add new customers and/or additional load to the transmission system.

Customer Service: Enhancements to the transmission customer experience such as outage planning and operational communications, timely estimates and project execution for transmission connected customers.

Delivery Point: The point of supply where the energy from the system is transferred to customers. This point is generally taken as the interface between utility-owned equipment and the customer-owned equipment.

Expected Service Life: The average time in years that an asset can be expected to operate under normal system conditions.

End of Life: the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences.

Frequency Deviations: Fluctuations beyond the normal operating frequency range.

High-Voltage Transmission Network: Interconnected circuits that operate at 115kV and higher voltage.

Interruption: A stop in the flow of electricity to a customer.

Key Assets: Major types of transmission assets defined as transformers, circuit breakers and conductors.

Long-Term Reliability: Reliability performance beyond the 5 year rate filing period.

Multi-Circuit Systems: Systems where power delivery points are supplied by more than one circuit.

Outage: Unavailability of electrical equipment due to disturbances, equipment maintenance, or equipment malfunction. Outages do not necessarily lead to interruptions for customers if there are backup or redundant facilities to maintain electrical supply.

Outage Restoration: Provisions to ensure timely and efficient response to failures, unplanned outages, or imminent risks to the transmission system to minimize customer interruption and prompt restoration to normal operating conditions.

Outliers: Individual assets or sets of assets whose performance is significantly different than the average performance of the system as a whole.

Power Quality: Delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform. Assessing customer concerns and implementing mitigation plans to address and rectify power quality issues for transmission connected customers.

Productivity: Implementation of new technologies and processes to enable operational efficiencies in the planning and execution of work programs aimed at reducing costs and enabling more efficient use of resources.

Redundancy: The inclusion of duplicate components to the system so that delivery points have multiple simultaneous connections. The purpose is to reduce the possibility of interruption in case of component failure.

Reliability: Maintaining the uninterrupted operation of the transmission system for all customers by sustaining the existing assets, replacing assets that are in poor condition and addressing transmission system performance outliers.

Reliability Risk: An index that provides leading directional indication of overall system reliability performance based on probabilistic risk of asset failures.

Safety: Eliminating and mitigating risk to public and employee safety in the operation of the transmission system.

Short-Term Reliability: Reliability performance within the 5 year rate filing period.

Single Circuit Systems: Delivery points that rely upon one circuit for the delivery of power. If that circuit fails then power is interrupted.

Sustainment Capital: Capital Investments made in order to maintain the current expected level of functionality and capability of system.

System Average Interruption Duration Index (SAIDI): The average outage duration for each customer served.

Transformer: An electric power equipment that changes the electricity voltage level. In Ontario, the transmission level voltage are typically transformed from 500kV to 230kV and 230kV to 115kV. To supply customers, 115kV and 230kV transmission voltages are transformed to distribution level voltages.

Transmission Stations: An electrical facility that connects a number or transmission circuits and transformers and performs a “hub” function for the flow of electricity across a region.

Transmission System Performance Outliers: Individual assets or sets of assets whose performance is significantly different than the average performance of the system as a whole.

Voltage Waveform: The shape of the 60Hz voltage curve observed at the supply point.

Stakeholder Session

Transmission Customer Engagement

In preparation for Hydro One's 2019-2023 Tx Application

March 29, 2017

Purpose of Stakeholder Session

Obtain input from Stakeholders as to the form and substance of Hydro One's upcoming Transmission Customer Engagement Process.

Why Customer Engagement

- Consistent with Hydro One's evolution to becoming a commercial entity: focus on customers, greater accountability for performance outcomes, and driving continuous improvements in efficiency and productivity company-wide.

- Inform the development of Hydro One's Transmission System Plan and Transmission Rates Application for 2019-2023 (to be filed Spring 2018)

- Meet or exceed the OEB's expectations pursuant to the Renewed Regulatory Framework (RRF) and meet the filing requirements relating to customer engagement from Chapters 2 and 5 of the Filing Requirements and the Handbook to Utility Rate Applications.

OEB Customer Engagement Filing Requirements

- Chapters 2 and Chapter 5 of the Filing Requirements and the Handbook require:
  - Engagement process be **designed** to identify customer needs and preferences;
  - Customer needs and preferences be **identified** as a result of the engagement process; and
  - Outcomes of the engagement process **inform** the asset planning process; specifically, how customer needs and preferences are **integrated** into an investment plan and how the **trade-off** between outcomes and costs has been made.

Customer Engagement – Hydro One Experience

- Hydro One has conducted two full customer engagement processes to support its
  - 2017 - 2018 Transmission Revenue Requirement Application, and
  - 2018 - 2022 Custom Incentive Distribution Rates Application.
- In both applications, the customer engagement process informed Hydro One's judgment on where customer needs and preferences, customer rates, and asset needs are aligned in the respective TSP and DSP.

Transmission: What We Heard

- Timing: engagement did not take place early enough to have impacted business decisions;
- Participation Rates were low
- Did not engage with all customers who will be impacted by the proposed rate increases (i.e., end-users of LDCs);
- Reliability Performance: top quartile status not adequately communicated;
- Information confusion;
- Investment Scenarios: not enough options, no zero rate option;
- Outcomes: reliability risk model not accepted as sole outcome measure; risks exaggerated;
- First Nations and Métis not represented; and
- Purpose of Engagement: customers may not have understood what was being asked of them.

Your Thoughts and Input

- Number of scenarios and how scenarios should be differentiated: rate impact, outcomes valued by customers, or size of 5-year capital envelope;
- Identification of outcome measures;
- How to capture needs and preferences of Distribution-connected end-use customers (i.e. end users of transmission services who are not transmission-connected customers per the Transmission System Code);
- How to capture needs and preferences of First Nations and Métis customers;
- Minimizing information Confusion;
- Timing;
- Participation Rates; and
- Clarity of Purpose
- What other issues should we be aware of?

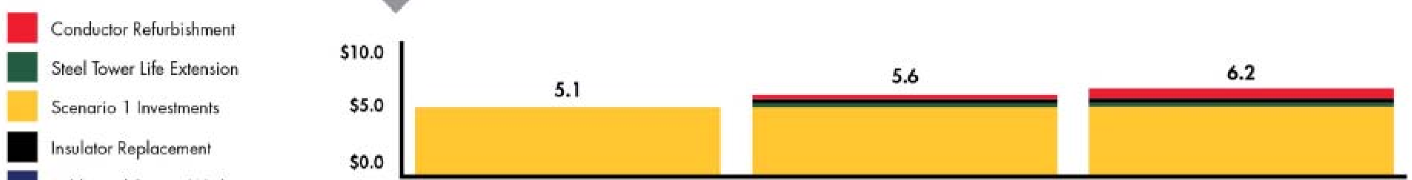
Recall the “scenarios” we previously used?

hydro one

OVERVIEW OF THREE POTENTIAL SCENARIOS

hydro one

2016 – 2020 Transmission System Net CapEx ($B)



		SCENARIO 1	SCENARIO 2	SCENARIO 3
Capital Spend	Sustainment ($B)	3.5	4.0	4.6
	Development ($B)	1.1	1.1	1.1
	Other ($B)	0.5	0.5	0.5
Expected Outcomes	Frequency and duration of interruptions	▲ Expected increase in line-related interruptions	▶ Some increase in lines risk offset by limiting unplanned outages and improved station performance	▼ Reduce risk from lines and continue to limit exposure to unplanned outages
	Reliability risk[1]	▲ Risk is expected to increase	▶ Current risk expected to remain essentially unchanged	▼ Risk is expected to decrease
Rates	Transmission rate impact (Compound Annual Growth Rate for 2017 – 2020)[2]	▲ ~5.8%	▲ ~6.3%	▲ ~6.8%

1. Reliability risk is a probabilistic calculation based on asset demographics and the historical relationship between its age and its failure or replacement.
2. Excludes impacts of potential changes in load forecast and any potential change to operations and maintenance spending.

Scenarios

Issue: Number of scenarios and how scenarios are differentiated.

Straw Dog: Four scenarios – Differentiated by size of Rate Increase (%) and resultant Outcomes

Scenario #1: Investment plan resulting in zero percent rate increase

Scenario #2:
Scenario #3:
Moderate rate increases with different investment plans and outcomes

Scenario #4: Investment plan resulting in a higher rate increase.

As in previous engagements – the scenarios are intended to represent a range of alternatives, and are not suggested as discrete choices

Scenario Issues

- Is it appropriate to differentiate based on rate increase or should other differentiators be used?
- Are 4 scenarios the right number to go with?
- Is a 0% rate increase an appropriate starting point for scenarios?

Outcome Measures

Issue: Which outcome measures are appropriate?

Options: Reliability Risk
T-SAIDI
T-SAIFI
Outlier Performance
Safety
Environmental Impact

- Other outcome measures?
- How many measures should be discussed?

Customers Engaged

Issue: How to capture needs and preferences of Distribution-connected end-use customers (i.e. not -transmission-connected)

Straw Dog:

Since LDCs serve these customers, rely on LDCs to represent their customers' needs and preferences to the Transmitter, based on

- their own customer engagement work (including Hydro as well as other LDCs)
- Results of LDC conducted surveys

Alternatives:

- Survey LDC customers directly (potential confusion?)
- Review LDC customer engagement evidence filed with the OEB
- Separately survey LDCs as representatives of their customers

Other approaches?

First Nations and Métis

Issue: First Nations and Métis Engagement

Straw Dog: Rely on the customer engagement work of Hydro One Distribution and other LDCs

» Results of LDC conducted surveys
» LDC customer engagement evidence filed with the OEB
» Survey of LDCs as customer representatives, focusing on First Nations and Metis customers specifically

Alternative: Engage directly with First Nations and Métis

Other approaches?

Information Confusion

Issue: Information Confusion

Specific information to clarify with customers:

- – End of Life
- – Expected Service Life
- – Role of age vs condition
- – Reliability
- – Reliability Risk
- – Service Interruption vs Outage
- – Hydro One's historical reliability performance

Other Issues

Timing: Hydro One plans to conduct its Tx Customer Engagement in April- May 2017, and complete the engagement by the end of May 2017, to allow it to commence development of the investment plan

Participation Rates:

Recognizing customers' time constraints, instead of 3 discrete waves (one-on-one meetings, workshops, and an on-line survey), offer customers a choice of channels to provide their needs and preferences

Purpose: Spend more time explaining the purpose of the engagement, its role in the process, the need to balance competing priorities, and any planning constraints facing Hydro One in preparing an investment plan

What other issues should we be mindful of?

What other input or advice can you offer?

Hydro One Networks Inc.
2019-2023 Transmission Rate Application

Transmission Customer Engagement Stakeholder Session

Summary Report

Delta Chelsea Hotel
Toronto, Ontario

March 29, 2017

Session Overview

The session began with an introduction provided by Jody McEachran, Regulatory Affairs, Hydro One. Mr. McEachran highlighted that the purpose of the session is to engage stakeholders in an interactive discussion about the upcoming Transmission Customer Engagement Process being planned in preparation for the 2019-2013 Transmission Rate Application.

An overview of the agenda was then provided by the session facilitator Tracey Ehl, Ehl Harrison Consulting Inc. All stakeholders introduced themselves, including their names, organization and position. Introductions were followed by a presentation by Oded Hubert, Vice President, Regulatory Affairs, Hydro One Networks.

Participants were encouraged to ask questions and provide feedback throughout the delivery of Mr. Hubert's presentation. This report is a synthesis of the discussion from the session, organized by key question. In each section, stakeholder comments are numbered, with the responses, by either participants or staff, directly following. Comments and questions received after the session are not reflected in this report.

A list of participants can be found in Appendix A.

Stakeholder Discussions

A. **Transmission Customer Engagement** (Oded Hubert)

Summary: Mr. Hubert highlighted the importance of the customer engagement component of the upcoming Transmission Rate Application and emphasized that the session was aimed at gathering the thoughts and insights of stakeholders on the form and substance of the engagement activities. Mr. Hubert recapped that Hydro One has conducted two full customer engagement processes to support recent applications. He reviewed key process-related challenges from these two processes and sought input and discussion about approaches to addressing them. Key topics included scenarios, outcome measures, engagement with distribution-connected end-use customers, First Nation and Métis engagement, information confusion, and other issues.

There were a number of key discussion themes that arose from the conversation, as follows.

- *It is important to identify the purpose of the engagement (build plan or tweak plan) and then identify the approach.*
- *Stakeholders felt strongly that the OEB's decision regarding the current (2017-2018 Transmission) application that is before the Board would be important context to this engagement process, and proceeding prior to the decision is not ideal.*
- *The scenarios may not be the most effective starting point for the engagement, because this quickly narrows stakeholder focus, away from system considerations of the application.*
- *The schedule, as presented, is very aggressive. There may be some benefit to continuing the engagement process while the application preparation is ongoing.*
- *Additional (local/granular) information and context (including about past spending and performance trends) should be provided to customers in order to engage in more meaningful feedback/dialogue. The story has to be linked to customer experience outcomes.*

- *There would be great benefit for this and future applications if focus was given to educating/explaining key terms and business practices.*
- *Any engagement approach has to be balanced with the potential for consultation fatigue.*
- *With respect to understanding the needs and preferences of LDC customers, while it is possible to learn from engagement done by LDCs (through data mining), it is still important that Hydro One conduct an engagement processes to hear from end users.*
- *Industry best practices are not readily available. To overcome this, one approach may be to seek the input of a small sample of customers about the engagement process. This may provide valuable input to how process design could support their engagement and more effectively meet Hydro One's application needs.*

General discussion:

1. Is proposed Rate Application expected to be aligned with the Transmission System Plan that was filed with the 2017-2018 Application?
   - Yes.

2. What was the participation rate of LDCs in the last Tx Engagement? The reason for this question is to discern whether the LDCs represent the interests of their customers.
   - Participation rates are not available at this time.

3. Customers need to understand how reliability is affected by Transmission and Distribution. Where (in which system) should the investment be?
   - This was not explored in the previous engagement efforts.

4. Slide 6, what we heard, should include mention of the feedback related to the difference between multi circuit and single circuit systems.

5. Hydro One should wait for the OEB decision before talking to customers again.
   - This will assist in defining parameters and scenario building.
   - Results from Board decision will provide direction that may point you in a different direction.

6. "I'm not sure how you can go to your customers until the decision is known."

7. It is premature to start working on scenarios at this point. Hydro One should focus on designing the process and this will inform how the scenarios are developed.

8. Hydro One should also seek feedback on the incentive regime.

9. Providing customers with an understanding the historic investment strategy and spending will help to inform a good discussion about the future.
   - An educational component will be very important.

How many scenarios should be utilized? Is this the right approach?

1. While scenarios are important, Hydro One may want to consider a more organic process.

2. I have an issue with scenarios. Customers pick the scenario that will benefit them.

- (Hydro One staff) When we talk to customers, they all bring their own issues and preferences which are focused on the individual customer.
- Responses are diverse among customers.
- Scenarios outcomes should be refined by customer.

3. During the previous engagement, was data presented on different types of circuits?
    - (Hydro One staff) Data was presented at a network level. Greater granularity may be of assistance. We have 10 geographic areas across the province. This will provide information relevant to specific groups. This information base could help inform the engagement process

4. Momentary interruptions are a big issue for some industrial customers.
    - (Hydro One staff) Power quality is a 'fuzzy' issue but we had great feedback from our customers on this. As a result, we are focusing more on this in our business plan.

5. People (customers) want to better understand what investment is being done on 'my network' on 'my supply'.

6. Scenarios should show customers what the outcome is for different levels of spending and for spending the same amount (i.e. the middle scenarios). For the middle scenarios, there are different outcomes depending on where the spending is done. Outcomes need to be refined to demonstrate impact and delineated by region.

7. It is not clear to me how Hydro One incorporates a five-year plan (into two-year scenario) and is able to incorporate the outliers? My sense is that there should be more latitude to respond to outliers. Scenarios are 'grab-bags' with a certain amount of latitude for the opportunity to discuss the trade-offs

8. Customers need to understand the base scenarios (and performance trends over time). Under Scenario 1, customers need to see why a continued level of spending is not adequate given past performance. Why is a further increase needed? Under Scenarios 2 and 3, understanding performance trends historically and the impact moving forward with the spending is important for customers to understand. Consider what a rate reduction scenario (and the associated performance trends) looks like.

9. More clarity on outcomes is needed. Information should be provided about what is needed for a local area vs. system wide needs.
    - Take it to a level that we can see reliability risk.
    - Scenarios 2 and 3 will quickly become the focus.

10. The way that the issue is framed will change the feedback/outcome from stakeholders.
    - Reliability risk is not well understood.

11. Hydro One should start with consideration of who the customers are and what are the outputs that are important to them. This should inform the design of a survey that is most appropriate for them.

12. It is important to start with scenario 1 and to include explanation of the details that are contained within it, such as whether it is based on last five year system wide performance or whether it is disaggregated.

  - What are you going to project for end of life assets? This is an important part of the baseline.
  - More clarity is needed about where we are starting from.

13. There is concern about providing customer with end of life metrics, which can be misleading or misunderstood.

14. Are you still continuing with reliability risk model?
    - Yes, Hydro One is continuing to develop the tool, along with exploring its role. It was developed as an outcome measure.

15. Hydro One should still be using a reliability risk model.

16. What I heard about the last engagement process was that there is a need to understand performance in the past, what spending has been done, and why you need the extra funding. This data/information will help get support.
    - Why don't you demonstrate to customers what a reduction in rate would result in? Customers could then understand outcome.

What outcome measures are appropriate?

1. How can we differentiate reliability? How can we better understand the customer perspective?
    - During consultations, it was suggested more granular information was preferred.
    - Aren't there meetings throughout the year with large customers to discuss the key issues? Do customers want to get additional details?
    - (Hydro One staff) When meetings happen on a monthly basis or ad hoc, the focus of meetings is often about specific events at the customer level, with less focus (if any) at the system level. Customers appreciate understanding the network but then close in on their specific context.

2. Outcome measures that speak to equipment performance, number of customer interruptions, number of customer interruption hours are important and understandable.
    - T-SAIDI and T-SAIFI are not necessarily the most accessible measures to understand in a meaningful way.

3. There were outcome measures discussed (at hearing) that are worth considering, including: Power quality; Number of customer interruption hours/year; Equipment unavailability, failures; Outage versus interruption.

4. The measure should be T-SAIDI and T-SAIFI, but explained in a different way.

5. With respect to geography, what do you do with this information? Will it be used to direct funding? Data on reliability in each geographic area would be very good data to have.
    - (Hydro One Staff) It is a good idea to provide detailed, localized data.

6. Equipment unavailability is an important metric to convey information about equipment failure, how long it is unavailable for and why.

7. When I think of (engagement) slides from last time, slides on T-SAIDI and T-SAIFI showed an average over the last five years. It would have been interesting for customers to see the historic trends, along with looking at five years into the future. This is how you can build up the story for the scenarios.

8. Concern was expressed about showing percentage of outages. There should be an absolute number.

9. If the reliability risk model is not being used to make decisions, it is not that valuable to customers.
   - (Hydro One staff) Hydro One still views Reliability Risk as a meaningful outcome metric.

10. What are the metrics that Hydro One is watching when developing programs? These should be the ones that are also the focus of customer engagement.

11. Hydro One should start by looking at the experience with its own LDC and share this information.

12. It would be very helpful to ask customers to identify meaningful metrics to them. They will ultimately want to understand what they will experience.

How can Hydro One capture needs and preferences of Distribution-connected end-use customers?

1. First, the purpose has to be well understood. Is it to drive the plan development, or to tweak it after the plan has been developed? (Hydro One staff explained that it is the former.) Engage customers where there is material consideration.

2. Concern was expressed about LDCs representing their end-use customers in this type of engagement scenario.
   - They have their own incentives, so care has to be exercised.
   - Mining data from LDCs is challenging, and may not yield useful information for the purpose.
   - Surveying customers directly may be a better approach, however it may lead to confusion.

3. There is a large information gap related to Hydro One business terms and concepts. For example, what is a major event?
   - It is important to get higher level information from customers.
   - You do need to talk to end users but don’t ask how money should be spent.
   - Need to think about what we want to know from end users.

4. If you talk to customers about reliability and rates, input will be contextualized by local inputs/outcomes. This could assist to get sense of the level of satisfaction and then this can inform planning.

5. The customer data collection by LDCs has been fairly rudimentary and self-serving.
   - It is important to understand what the LDCs are saying and their perceptions of inputs.
   - As we move forward, discussion should be more organic.

6. Depending on who you talk to you, there will be different perspectives.

7. What do you want to do with the customer data? If it is to drive the plan we have an issue because we are not talking to the right people. If it is to tweak then maybe it is not as big of an issue
    - Not sure where the Board is going with engagement, as they seem to want engagement but it doesn't seem to impact decisions.
    - (Hydro One staff) For clarification, the purpose of engagement is to inform the plan prior to its development.
8. What is the different between informing and tweaking
    - (Hydro One staff) "Tweaking" is presenting the plan to customers and gathering feedback. Informing is to get input into the development of the Plan

How can Hydro One effectively engage First Nation and Métis?

1. Why does Hydro One not use process defined in the 2007/2008 hearing? That was a robust process and should be utilized again.
    - (Hydro One staff) Hydro One did engage with First Nation and Metis at that time. That was a very large development plan for the entire province with impact on both t on and off-reserve land, but now we are in a sustainment' approach, so a different engagement approach was taken.

2. What do you think would be different in this customer group?
    - (Hydro One staff) Issues are wide ranging. Reliability is important, as are land rights, arrears, affordability, the proposed First Nation rate, past grievances, and past issues with Hydro One.
    - Other than these issues, what would inform a transmission plan in particular for this customer group?
    - (Hydro One staff) Hydro One would need to be clear on what the scope is of a Transmission-focused First Nations and Metis engagement.
    - Certain types of spending already involve engagement with these communities (i.e. Section 92).
    - (Hydro One staff) If we included First Nations in the Customer Engagement, this would not be the only forum, but we would be adding another level of discussion with First Nations.
    - How are First Nations and Métis engaged in regional planning? The IESO has set up local advisory committees for regional planning.
    -
3. This customer group should be engaged differently, through a lens of developing economic and social opportunity through the power system.

4. Best practices have been previously shared at a hearing and should be implemented here as well.

How can information confusion be addressed?

1. There needs to be an information/educational component to this engagement process, if the discussion is to be meaningful. For example, people don't understand the difference between end of life and expected service life.

2. The difference between service interruption and outage is confusing. Hydro One may not even need to speak about outages. Customers are most interested in service interruptions.
   - (Hydro One staff) When we talked to transmission customers, they do seem to understand this difference, as they interact with Hydro One on both equipment outages and interruptions.

3. Whatever information you convey to tell the story should include outcomes. The story has to flow into the outcomes.
   - (Hydro One staff) We are planning on informing the customer engagement process with new data but not any new concepts, such as reliability risk, which was introduced in the last engagement process.

Timing

1. Participants emphasized the importance of waiting for the (Board) decision before starting this engagement process, as one will inform the other.

2. Has the engagement consultant already been chosen?
   - (Hydro One staff) A vendor has not been chosen. It is anticipated that the engagement will include a number of channels, giving choice to customers on how they can provide their input.

3. A market research approach is more appropriate than opinion polling for this process.

4. How does the information that is collected get blended together?
   - (Hydro One staff) This is a real challenge. Education/framing is a huge undertaking, requiring time spent with customers. How much time can we actually get people to spend with us?
   - (Hydro One staff) We will be thinking about how can we segment our customers and provide the information that they need so they can provide input to better inform our plan.

5. Won't the anticipated decision impact plan going forward?
   - (Hydro One staff) Definitely. Customer Engagement is to inform the plan but we will also be informed by the Board Decision. There is a risk both to engaging early and to waiting.

6. (Hydro One staff) Should we continue engagement process into plan development phase?
   - An iterative process would be great, as long as all of the information gathered is incorporated back into the plan. An end date will be needed in this regard. Consider June timing or after the changes from the Fair Hydro Plan.

Participation Rates

1. The consultant hired will be able to assist with identifying and achieving good participation rates.

Purpose

1. Whatever you do will be more meaningful if you are able to provide them more information.

2. How are you framing the purpose? Inform plan or define spending?
    - (Hydro One staff) This engagement will inform the development of the plan.

What other issues should we be mindful of? What other advice do you have?

1. Is it Hydro One's position that you have to do a five-year application?
    - (OEB staff) Yes, this is the minimum period for a Custom IR.

2. Does anyone in North America do Transmission Customer Engagement? Can we look at best practices?
    - Staff and participants were not aware of current best practices. It was indicated by a participant that a lot of research was carried out in the past prior to the break-up of Ontario Hydro.

3. Make sure the engagement is meaningful to Hydro One and to customers.

4. What future Stakeholder engagement activities do you anticipate for this Application?
    - (Hydro One staff) This is still in planning stages, but information will be sent to you once it is known.

5. Is there an opportunity for Hydro One to meet with a small number of large industrial customers, LDCs and explore what approach to engagement might be meaningful to them?
    - (Hydro One staff) Yes. Also, LDCs were included in the invitation to participate in today's discussion, but due to schedule conflicts, none were able to attend.

Session Wrap-up

All stakeholders were thanked for their participation. Additional questions and/or comments were invited following the session.

Appendix A: List of Participants

Andrew Blair – Power Workers' Union
Bill Harper – VECC
Bohdan Dumka – SEP
Cary Ferguson – Anwaatin Inc.
Chris Codd – OEB Staff
Frederick Belanger – HQEM
Hanna Smith – IESO
Harold Thiessen – OEB Staff
Julie Girvan - CCC
Marion Fraser - BOMA
Mark Rubenstien - SEC
Megan Lunh - IESO
Roger Higgin – Energy Probe
Shelley Grice – AMPCO
Vicki Power – SEP

Hydro One
CK Ng – (Planning) Hydro One Networks
Erin Henderson – (Regulatory Affairs) Hydro One Networks
Jeffrey Smith – (Planning) Hydro One Networks
Jody McEachran – (Regulatory Affairs) Hydro One Networks
Oded Hubert – (Regulatory Affairs) Hydro One Networks
Scott McLachlan – (Planning) Hydro One Networks
Spencer Gill – (Customer Service) Hydro One Networks
Steven Vetsis – (Regulatory Affairs) Hydro One Networks
Warren Lister – (Customer Service) Hydro One Networks

Tracey Ehl – Facilitator
Jodi Ball – Note taker

ATTACHMENT 4: RELIABILITY RISK SUMMARY

The reliability risk model was introduced by Hydro One in 2016 to provide a method for demonstrating the value of sustaining investments to customers and to provide a directional indicator to assess the effect of an investment portfolio on reliability.

It is a simplified method to communicate risk to customers and stakeholders. It is not used to identify specific asset needs or justify investments. Asset needs are anchored by asset condition assessments and investments are justified by asset needs and prioritized in accordance with Hydro One's investment planning approach described in TSP Section 2.1, Investment Planning Process.

In order to solicit impact from customers the reliability risk model was one of several measures used in the 2017 Customer Engagement Survey to quantify and communicate the outcomes associated with various investment scenarios. Customer input was a key factor that informed Hydro One's overall investment plan, which underpins this rate application. During customer engagement, there was no preferred investment plan. The risk prioritization investment planning methodology which was used to prioritize the investments underpinning the TSP[1] was under development and not available as an alternative communication tool. As such, the reliability risk model was the method used to communicate risk to customers.

In its Decision in Hydro One's last Transmission Rate Application (EB-2016-0160) the Ontario Energy Board ("OEB") found that the model needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability. A third party assessment completed by Metsco

[1] Detailed in TSP Section 2.1.

Energy Solutions Inc. has led to a similar conclusion and recommendations as discussed in TSP Section 1.4, section 1.4.2.14.

Hydro One is aware of reliability forecasting models however comprehensive assessment and testing of these models are not complete. Hydro One has completed substantial work in developing and refining hazard functions of its assets as discussed in TSP Section 1.4 which form a good baseline for forecasting investment requirements. Hydro One will continue to explore and assess other reliability forecasting models to quantify the outcome of its investment plan in the future.

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2018 Large Tx Customer Satisfaction

Understanding Dimensions of Satisfaction and Dissatisfaction

Hydro One
483 Bay Street
Toronto, ON M5G 2P5

hydro one

October 2018 :: Review Draft

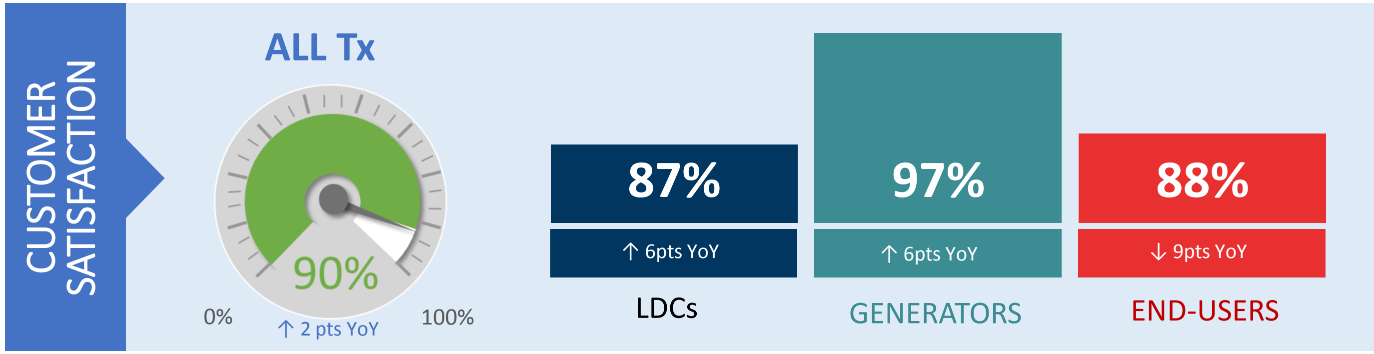
Summary: *2018 LTX Report*

1. **Hydro One's CSAT continues its upward trend and reaches an all-time high, with marginal improvement among Generators and LDCs effectively neutralizing a significant decrease among End-Users.**

2. ***Customer Service*** **is the dimension on which Hydro One has the highest levels of satisfaction.**

3. ***Product Quality & Reliability*** **shows room for improvement, particularly on customers' experience of unplanned outages.**

4. **Environmental controls were introduced in 2018 to gauge the impact of economic and political factors that are outside of Hydro One's influence.**



HIGHEST PERFORMING ATTRIBUTES

- Overall customer service (93%)
- Communication methods (93%)
- Service received from account executive (90%)
- Accessibility (87%)
- Understanding business needs (85%)

OPPORTUNITIES FOR IMPROVEMENT

- Duration of unplanned outages (48%)
- Number of unplanned outages (50%)
- Good value for money (58%)
- Communication during outages (62%)
- Time to restore power (66%)

Insights: Drivers of CSAT

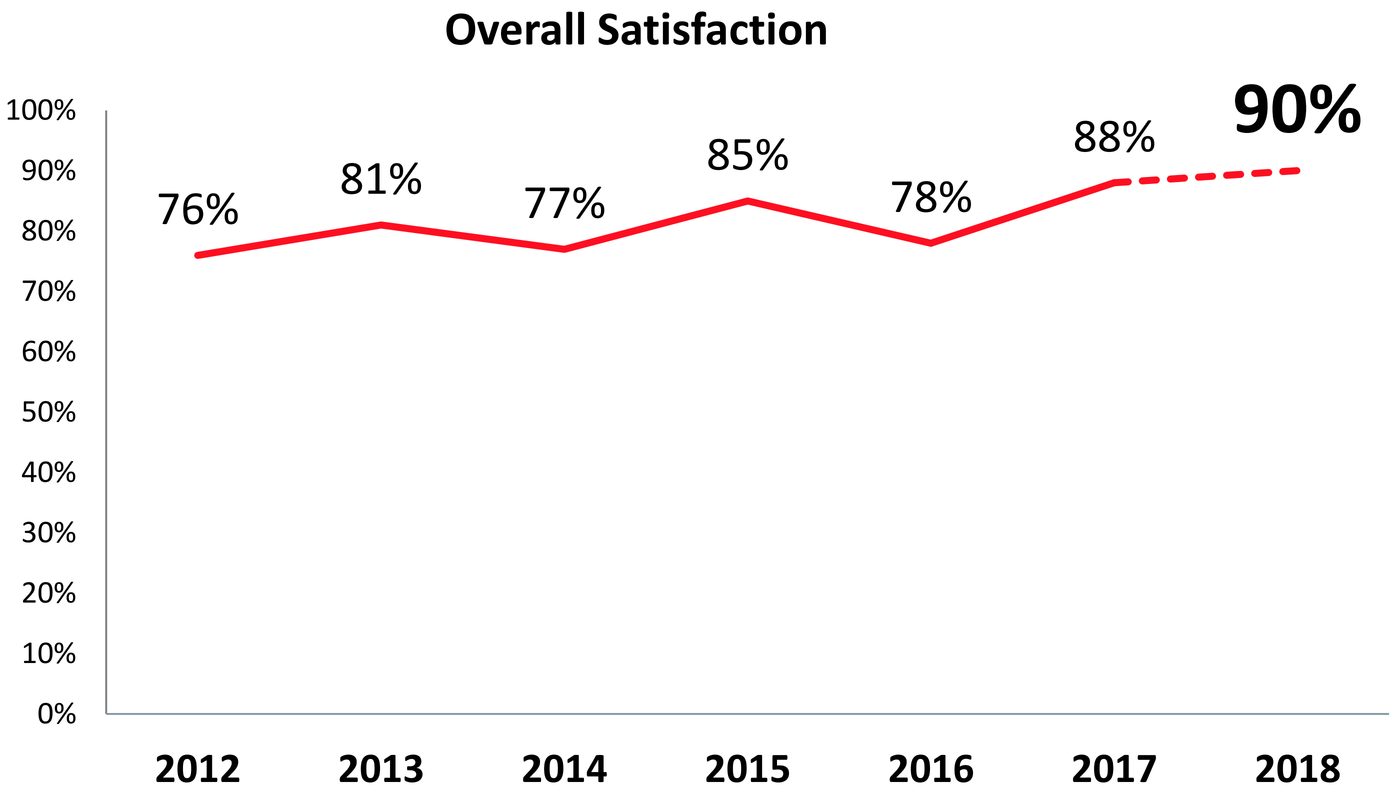
- *Customer Service* is the strongest driver of CSAT. This factor has an emphasis on communication:
  - communication methods
  - overall communication
  - service from Key Account Executive
- Being able to recall an unplanned outage has a negative effect on CSAT, which highlights the need to improve customers' experience of unplanned events.

Key Metrics of Satisfaction

Overall Satisfaction (All Tx): Overall satisfaction continues to trend upwards from 2016, landing at an all-time high of 90%

Q

C2. Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?
[Asked of all respondents, n=112; valid responses n=112]



Key Insights

- Overall satisfaction continues to trend upwards from 2016, landing at an all-time high of 90%.
- Because there were no respondents who said “don’t know” to this question in 2017 and 2018, the results are reliably trackable. Therefore, we know that there has not been a significant change since 2017.

NOTE: Response "Don't know" (0% in 2017 & 2018) was excluded from this analysis. Statistically significant changes compared to the results from 2017 are indicated by ↑↓.

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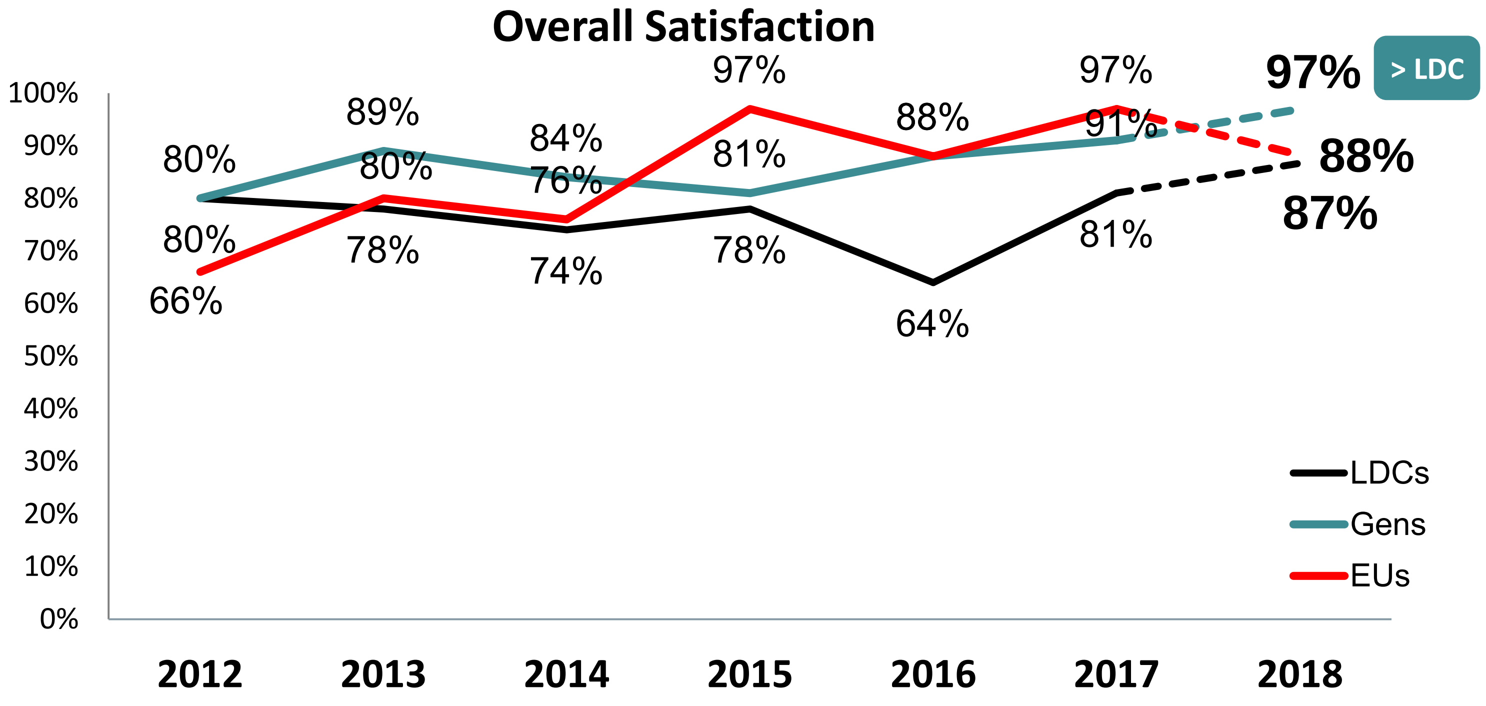
Overall Satisfaction (By Customer Type): Satisfaction among Generators and LDCs hits all-time high in 2018; End-Users down 9pts from 2017

Q

C2. Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?



	2012	2013	2014	2015	2016	2017	2018
LDCs	80%	78%	74%	78%	64%	81%	87%
Gens	80%	89%	84%	81%	88%	91%	97%
EUs	66%	80%	76%	97%	88%	97%	88%

Key Insights

- Upwards trend of Generator satisfaction continues from 2015, surpassing both other customer groups in 2018.
- LDCs continue to increase from their record low in 2016, albeit less sharply than in 2017.
- End-Users down 9 points from 2017. Due to the small sample size (n=34), this is not a statistically significant change.
- The increase among LDCs and decrease among End-Users has closed the gap between those two groups.

LTX Customer Type	Total Population	Sample Size
LDCs	66	45
Generators	63	33
End-Users	72	34

NOTE: Response "Don't know" (0% in 2017 & 2018) was excluded from this analysis. Statistically significant changes compared to the results from 2017 are indicated by ↑↓. Differences between customer type that are statistically significant at a 95% confidence interval are indicated.

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A Closer Look:
Overall Customer Satisfaction

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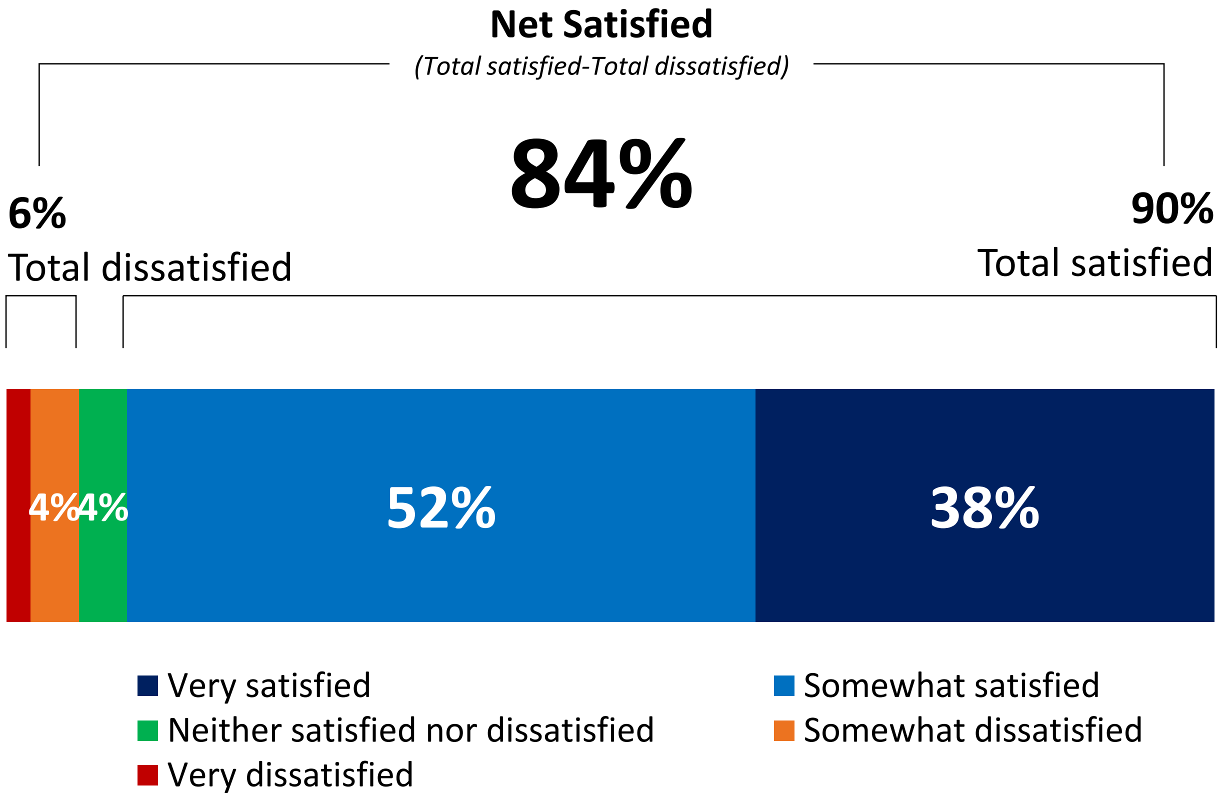
Overall Satisfaction: 9-in-10 (90%) LTX customers are satisfied with the service they receive from Hydro One

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?
[Asked of all respondents, n=112]



Key Insights

- Overall satisfaction with Hydro One among LTX customers is verging on universal, but there is room for improvement on intensity. Currently, half (52%) are *somewhat* satisfied, while 38% are *very* satisfied.

NOTE: Response "Don't know" (0%) was included in this analysis

Overall Satisfaction (By Customer Type): Nearly 9-in-10 customers are satisfied across all customer groups; satisfaction highest among Generators

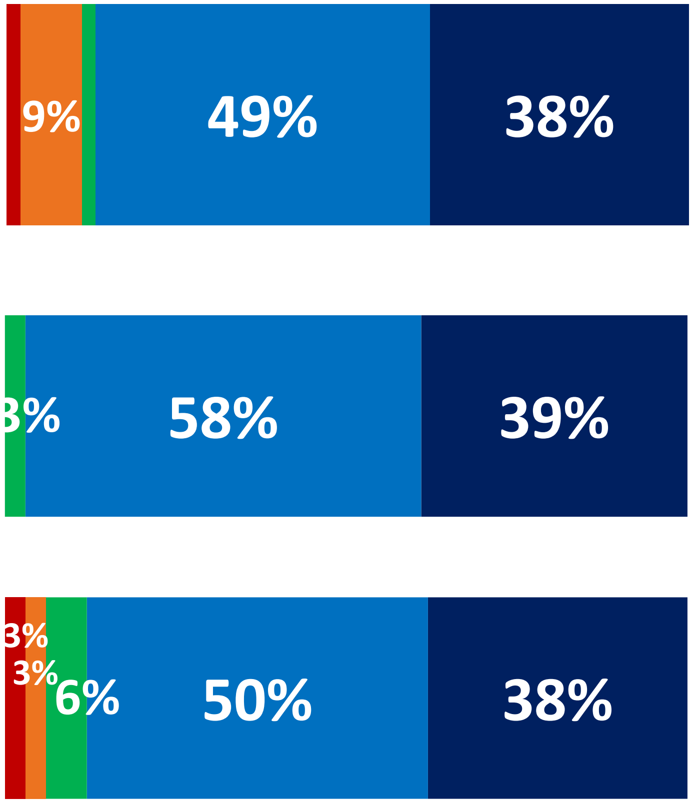
Q

C2. Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?
[Asked of all respondents]

LDCs
[n=45; valid responses n=45]

Generators
[n=33; valid responses n=33]

End-Users
[n=34; valid responses n=34]



	Total Dissatisfied	Total Satisfied	Net Satisfaction
LDCs	11%	87%	+76%
Generators	-	97% > LDC	+97%
End-Users	6%	88%	+82%

■ Very satisfied ■ Somewhat satisfied
■ Neither satisfied nor dissatisfied ■ Somewhat dissatisfied
■ Very dissatisfied

Key Insights

- The level of intense satisfaction is virtually identical across all three customer segments.
- The higher proportion of somewhat satisfied and complete absence of dissatisfied Generators results in universal satisfaction among that customer group.
- The proportions are small, but there are some dissatisfied LDC (11%) and End-User (6%) customers.

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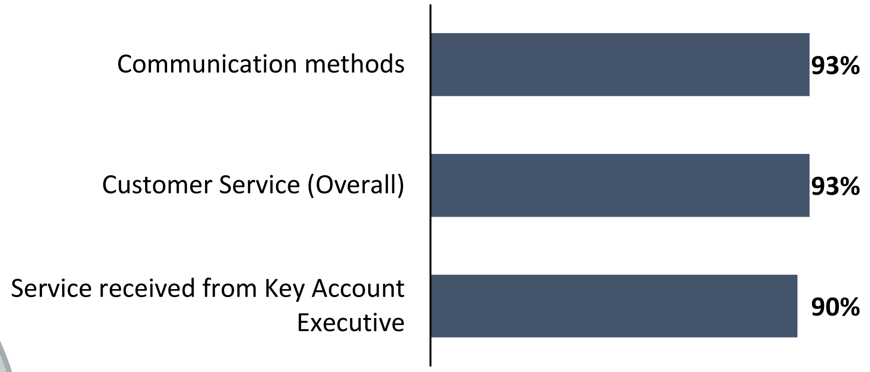
NOTE: Response "Don't know“ (0%) was included in this analysis
Differences between customer type that are statistically significant at a 95% confidence interval are indicated

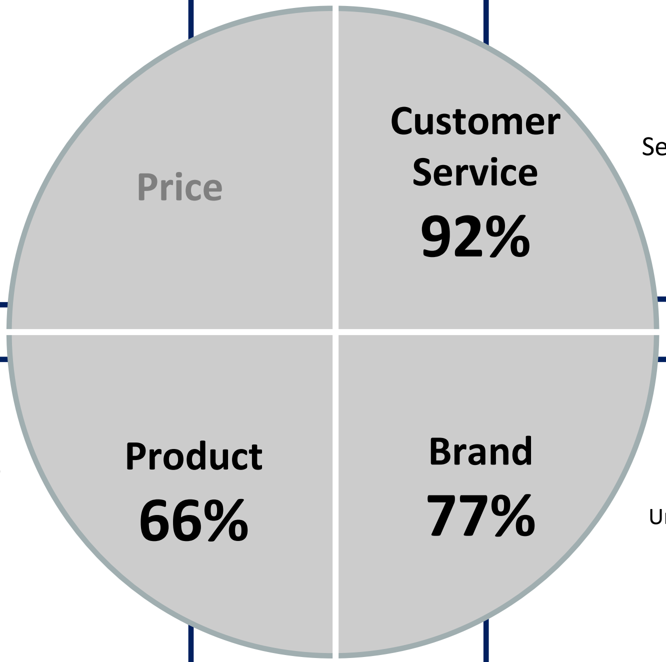
Survey Findings: Dimensions of Satisfaction (LTX – All Segments)

Price/Billing

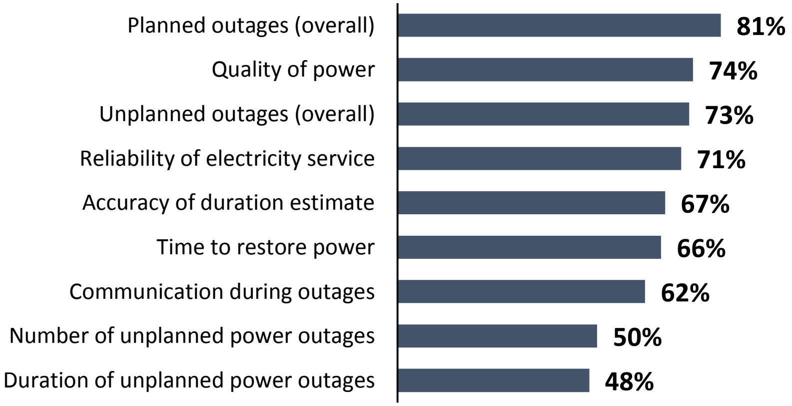
No price/billing questions pertaining to experience with Hydro One were asked of LTX customers

Customer Service





Product Quality/Reliability



Brand

NOTE: Percentages represent total satisfied (very and somewhat satisfied)
Response "Don't know" was included in this analysis.

Survey Findings: Dimensions of Satisfaction (LTX Segments)

Key Insights

- Generators are the most satisfied customer group across all dimensions.
- LDCs are the least satisfied, but just marginally.
- Customer service is the highest-scoring dimension across all LTX customer groups, whereas Product Quality/Reliability is the lowest,

Customer Service – 92%

LDCs	Generators	End-Users
2018	2018	2018
90%	96%	92%

Product Quality/Reliability = 66%

LDCs	Generators	End-Users
2018	2018	2018
62%	77%	64%

Brand – 77%

LDCs	Generators	End-Users
2018	2018	2018
73%	88%	73%

NOTE: Percentages represent total satisfied (very and somewhat satisfied).
No pricing questions were asked of LTX customers.
Response "Don't know" was included in this analysis.

Survey Findings: Dimensions of Dissatisfaction (LTX Segments)

Key Insights

- Dissatisfaction with customer service is nearly non-existent within these customer groups.
- Overall, Generators seem less dissatisfied than other customer groups, which aligns with their overall increase in overall customer satisfaction.
- 1-in-5 LDC and End-Users are dissatisfied with product quality and reliability in 2018. This is five times higher than dissatisfaction among Generators.

Customer Service – 1%

	LDCs	Generators	End-Users
2018	1%	1%	1%

Product Quality/Reliability – 15%

	LDCs	Generators	End-Users
2018	19%	4%	19%

Brand – 9%

	LDCs	Generators	End-Users
2018	10%	4%	11%

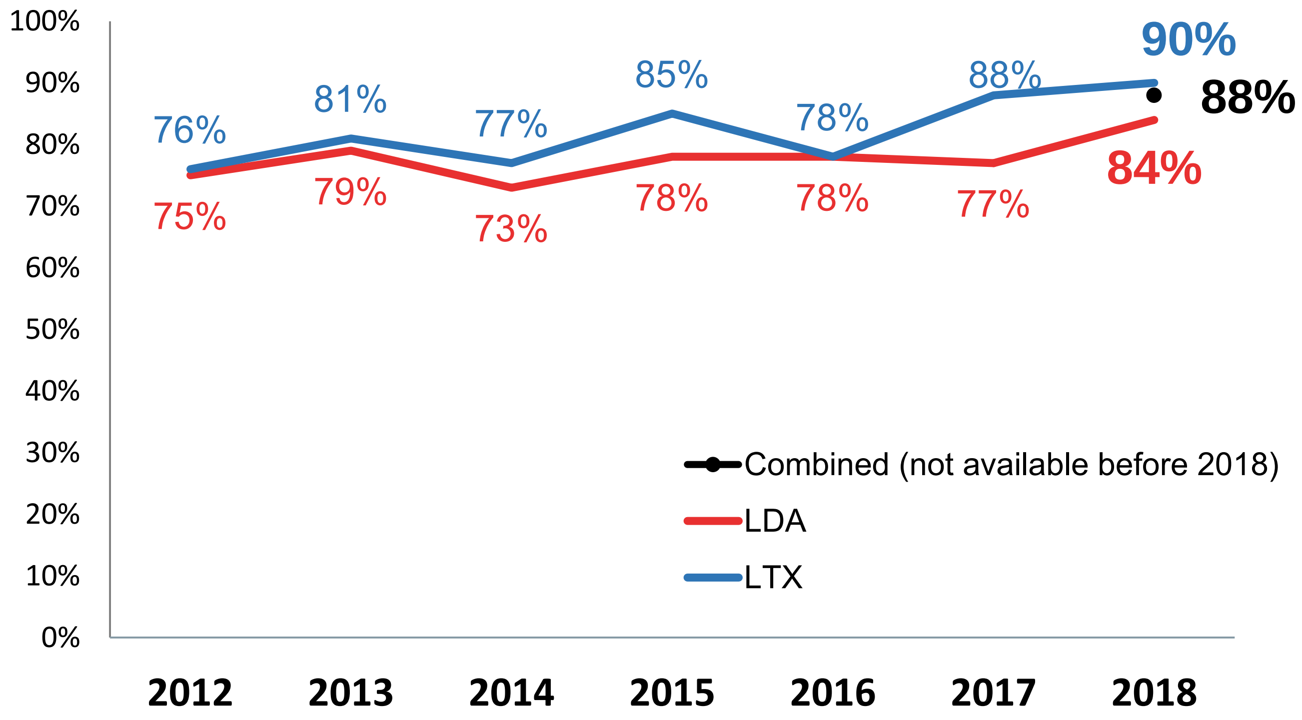
NOTE: Percentages represent total dissatisfied (very and somewhat dissatisfied) or total disagreement (strongly and somewhat disagree).
No Price/Billing dimension exists for LTX customers.
Response "Don't know" was included in this analysis.

Combined LTX and LDA Results

Overall Satisfaction: LTX customers give a marginally higher satisfaction rating than LDA customers

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?

Overall Satisfaction



Key Insight

- Combining LTX and LDA customer results does not have a significant impact on overall satisfaction, but there are marginal differences across the three dimensions.

Average **Customer Service** Satisfaction Scores	Average **Product** Satisfaction Scores	Average **Brand** Satisfaction Scores
Combined **90%**	Combined **67%**	Combined **76%**
LDA **86%**	LDA **70%**	LDA **72%**
LTX **92%**	LTX **66%**	LTX **77%**

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Regression Analysis: Identifying Drivers

Using Regression Analysis: Identifying drivers of customer satisfaction

What is Regression Analysis?

Regressions are another means of determining importance.

- A regression allows us to take all the questions that may explain a key question we are interested in and see which of these is the most important.
- Regressions do this by holding all the likely suspects constant and varying one question at a time to see which questions (explanatory variables) have the greatest impact on the key question (dependent variable).
- In this study, we use regression to understand **why some respondents rate their satisfaction with or likelihood to recommend Hydro One higher than others.**

We use ***Factor Analysis*** to explore underlying dimensions and structure the regression analysis.

- A factor analysis finds the true underlying dimensions of customer satisfaction that explain the pattern of responses to the larger set of attributes.
- Factor analysis allows us to find which attributes mean similar things to customers. The use of factor analysis allows us to determine which attributes should be grouped together in order to conduct meaningful analysis.

Identifying drivers of CSAT

CSAT
*“Overall, how **satisfied** are you with Hydro One?”*
Measures **overall attitude** towards Hydro One.

What drives each of these measures?

The Regression Model: Identifying drivers of customer satisfaction

Price/Billing

Fairness of the Global Adjustment (GA)
Fairness of the Hourly Ontario Energy Price

Customer Service

Communication methods
Customer service (overall)
Service received from Key Account Executive

Participation in CDM programs
Provision of information on CDM tools and programs by the IESO

Product Quality/Reliability

Planned outages (overall)
Quality of power
Unplanned outages (overall)
Reliability of the electricity service
~~Accuracy of duration estimate~~
Time to restore power
~~Communication during outages~~
~~Number of unplanned power outages~~
~~Duration of unplanned outages~~
Recall of planned outage
Recall of unplanned outage

Brand

Accessibility
Understanding of business needs
Quality advice and guidance
Responds to needs
Ability to keep commitments
Ease of doing business
Trusted business partner
Good value for money

NOTE: Bolding denotes questions that were asked in the survey but not included in the summary score for the respective dimension.

Step 1 – Factor Analysis: Price/Billing

Price/Billing

Fairness of the Global Adjustment (GA)

Fairness of the Hourly Ontario Energy Price

Standalones:

- Fairness of the Global Adjustment (GA)
- Fairness of the Hourly Ontario Energy Price

NOTE: Bolding denotes questions that were asked in the survey but not included in the summary score for the respective dimension.

Step 1 – Factor Analysis: Customer Service

Customer Service

Communication methods
Customer service (overall)
Service received from Key Account Executive

Participation in CDM programs
Provision of information on CDM tools and programs by the IESO

Factors

Customer Service

Standalone:
- Participation in CDM programs
- Provision of information on CDM tools and programs by the IESO

NOTE: Bolding denotes questions that were asked in the survey but not included in the summary score for the respective dimension.

Step 1 – Factor Analysis: Product Quality/Reliability

Product Quality/Reliability

Quality of power
Reliability of the electricity service
Time to restore power

~~Accuracy of duration estimate~~
~~Communication during outages~~
~~Number of unplanned power outages~~
~~Duration of unplanned outages~~

Recall of planned outage
Recall of unplanned outage

Factors

Quality & Reliability

Standalones:

- Recall of planned outage
- Recall of unplanned outage
- Planned outages (overall)
- Unplanned outages (overall)

NOTE: Bolding denotes questions that were asked in the survey but not included in the summary score for the respective dimension.

Step 1 – Factor Analysis: Brand

Brand

Ease of doing business
Ability to keep commitments
Understanding of business needs

Quality advice and guidance
Trusted business partner
Good value for money

Accessibility
Responds to needs

Factors

Help & Commitment

Valued Partner

Accessibility & Responsiveness

NOTE: Bolding denotes questions that were asked in the survey but not included in the summary score for the respective dimension.

New to LTX :: *Environmental Controls*
Potential drivers of CSAT outside of Hydro One's control

It is important to distinguish between what is within, and what is outside of Hydro One's influence or control when it comes to drivers of customer satisfaction.

Perceptions of electric companies often tend to move with general perceptions of ***provincial government management in the sector*** rather than in response to the local utility.

In addition, perceptions of utilities are also strongly correlated with **financial circumstances**. In tough times perception and preference can change because customers are struggling with their bills, not because of anything the company has, or has not, done.

Control questions help distributors distinguish between:

a) utility driven programs that impact CSAT; and

b) uncontrollable external drivers that impact CSAT.

When conducting **brand research** in the energy sector, INNOVATIVE often tests multiple environmental control to assess what role predispositions (customer values and beliefs – which can be difficult and costly to change) play in the formation of a utility's brand health and reputation.

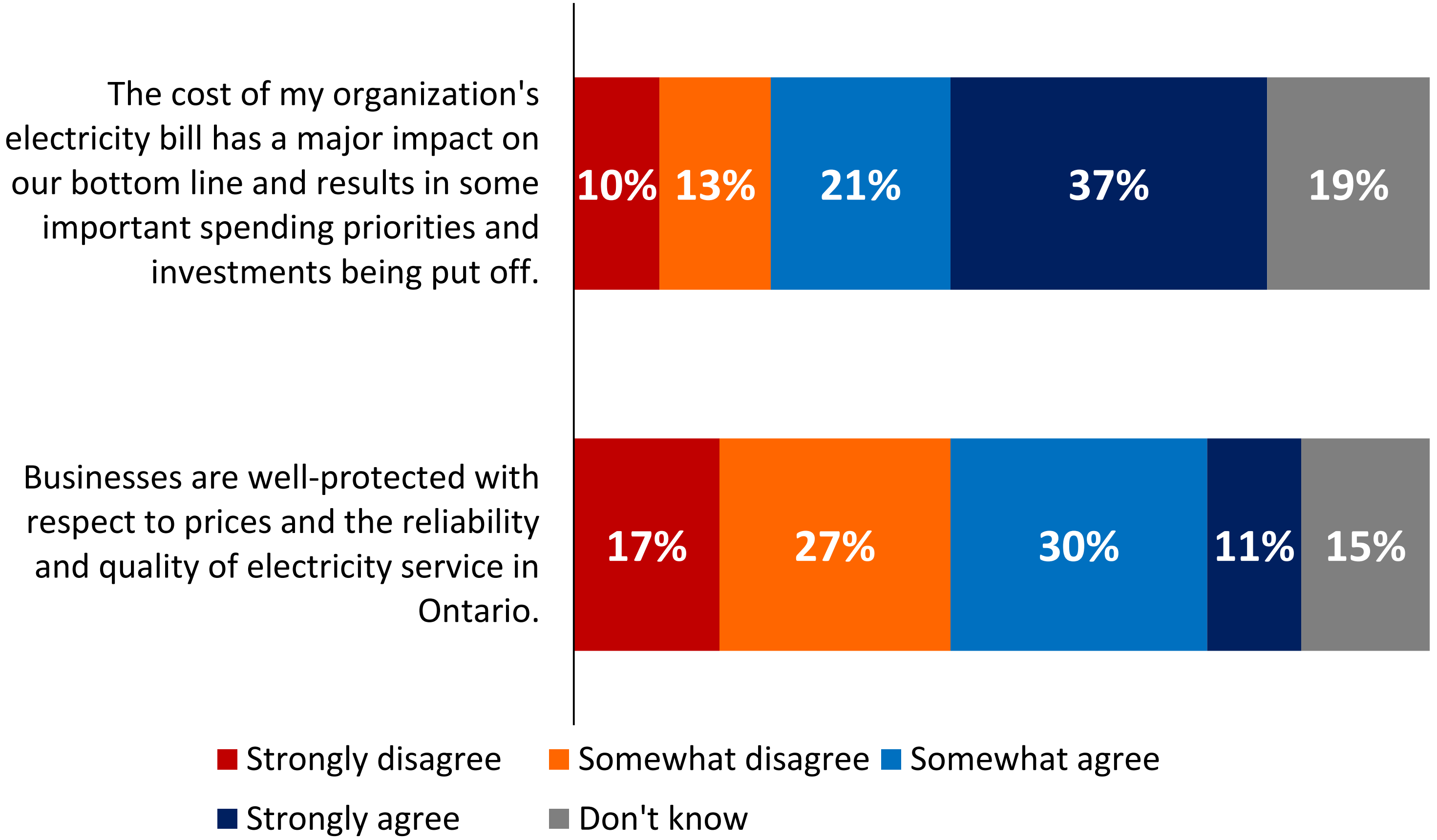
However, in **CSAT research**, we usually limit our environmental controls to two key questions to help capture external phenomena:

Government Management of the Electricity System: *Businesses are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.*

Financial Circumstances: *The cost of my organization's electricity bill has a major impact on our bottom line and results in some important spending priorities and investments being put off.*

Environmental Controls: Most (58%) LTX customers say their electricity bill is impacting their bottom line; opinion is divided on government protection

Q **H55 & H56.** For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[Asked of all respondents, n=112]



Key Insights

- A majority (58%) of LTX customers say their bottom line is being impacted by their electricity bill. Almost two-in-five (37%) *strongly* agree that this is the case.
    - LDCs: 36% agree
    - Generators: 55% agree **LDC**
    - End-Users: 91% agree **LDC, GEN**
- Opinion on whether or not businesses are protected in terms of prices, reliability ad quality of electricity service in Ontario is divided: 41% agree, and 44% disagree. However, the level of *strong* disagreement (17%) is marginally higher than the level of *strong* agreement (11%).
    - LDCs: 40% agree
    - Generators: 52% agree **EU**
    - End-Users: 32% agree

NOTE: Response "Don't know" was included in this analysis
Differences between customer type that are statistically significant at a 95% confidence interval are indicated.

The Regression Model: Identifying Drivers

Factors

- **Customer Service**
- **Reliability**
- **Help & Commitment**
- **Valued Partner**
- **Accessibility & Responsiveness**

Standalones

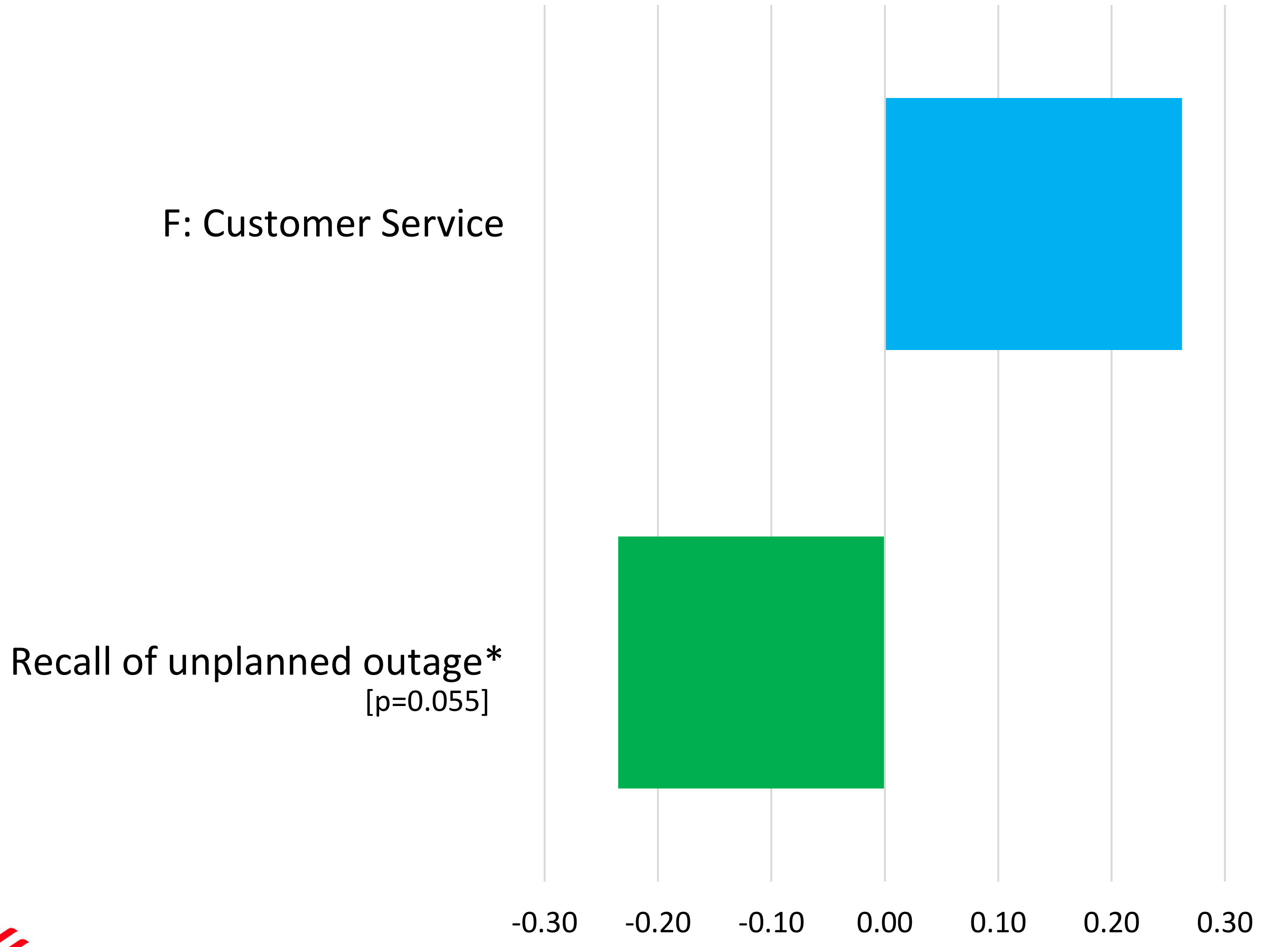
- Fairness of GA
- Fairness of HOEP
- Participation in CDM programs
- Provision of information on CDM tools and programs by the IESO
- Recall of planned outage
- Recall of unplanned outage
- Planned outages (overall)
- Unplanned outages (overall)

Controls

- Customer type
- Environmental controls

Regression Analysis: Identifying drivers of customer satisfaction

Customer service is the only factor that has a positive and statistically significant impact on customer satisfaction. Recall of an unplanned outage has a negative effect.



Adjusted R^2 = 0.289

Notes:
- Factor ***Customer Service*** combines “communication methods”, “customer service (overall)”, “service received from Key Account Executive”.

NOTE: Chart shows standardized beta scores. All drivers significant at a 95% confidence interval unless indicated otherwise.

Building Understanding.

Personalized research to connect you and your audiences.

For more information, please contact:

Jason Lockhart
Vice President

416-642-7177
jlockhart@innovativeresearch.ca

Susan Oakes
Vice President

416-642-6341
soakes@innovativeresearch.ca

Andrea Nuesser
Senior Consultant

416-640-4134
anuesser@innovativeresearch.ca

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2018 OGCC Customer Satisfaction

Understanding Dimensions of Satisfaction and Dissatisfaction

Hydro One
483 Bay Street
Toronto, ON M5G 2P5

hydro one

December 2018 :: Review Draft

Methodology

The findings presented in this report are based on an online survey carried out by Innovative Research Group (INNOVATIVE) for Hydro One.

The online survey was conducted from October 17th to November 2nd, 2018 among Hydro One LTX customers who had contacted the Ontario Grid Control Centre (OGCC) within the past year. A breakdown of LTX customer segments is included in the table below. In total, 107 participants completed the survey.

The below table shows the surveyed customer segments and their sample sizes:

Segment Size	TOTAL	LDC	Generator	End-User
Total Population Size	218	65	78	74
Surveyed	107	42	31	34
% Captured	49%	65%	40%	46%

Analysis Notation:

Throughout this report “Don’t know” was **included** as a valid response.

NOTE: *Graphs may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.*

Executive Summary

Summary: *2018 OGCC Report*

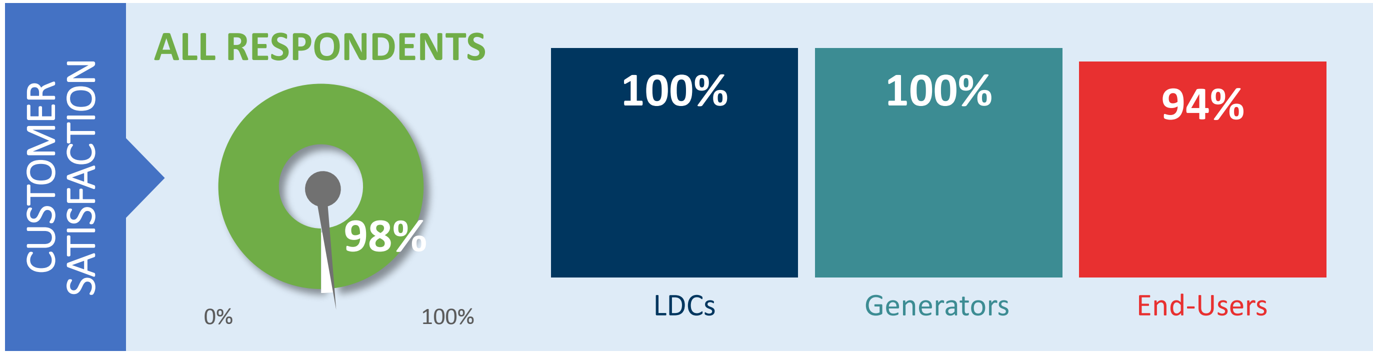
1. **At 98%, customer satisfaction with the OGCC overall is almost universal.**

2. **With the exception of the number of outages and management of <u>unplanned</u> outages, at least half are *"very satisfied"* with every performance metric they were asked about in the survey.**

3. **On a departmental basis, the intensity of satisfaction is highest for the Customer & Operating Support Department (74% *"very satisfied"*).**

4. **Intensity of satisfaction is lowest for the Operating Planning Department (60% *"very satisfied"*).**

5. **The number of <u>unplanned</u> outages has the highest level of dissatisfaction at 31%.**



HIGHEST PERFORMING ATTRIBUTES *("very satisfied")*

- **OGCC**: Relationship with OGCC (96%)
- **Outages**: Planned outage management (57%)
- **Operating Planning**: Proactive communication (65%)
- **Control Room**: Responsiveness (61%)
- **Customer & Operating Support**: Relationship with Network Management Representative (76%)

OPPORTUNITIES FOR IMPROVEMENT *(total dissatisfied)*

- **OGCC**: Sensitivity to operational impact of outages (8%)
- **Outages**: Number of unplanned outages (31%)
- **Operating Planning**: Handling of impactful outages (8%)
- **Control Room**: Prompt updates (3%)
- **Customer & Operating Support**: Effective communication (2%)

Insights: *Drivers of CSAT*

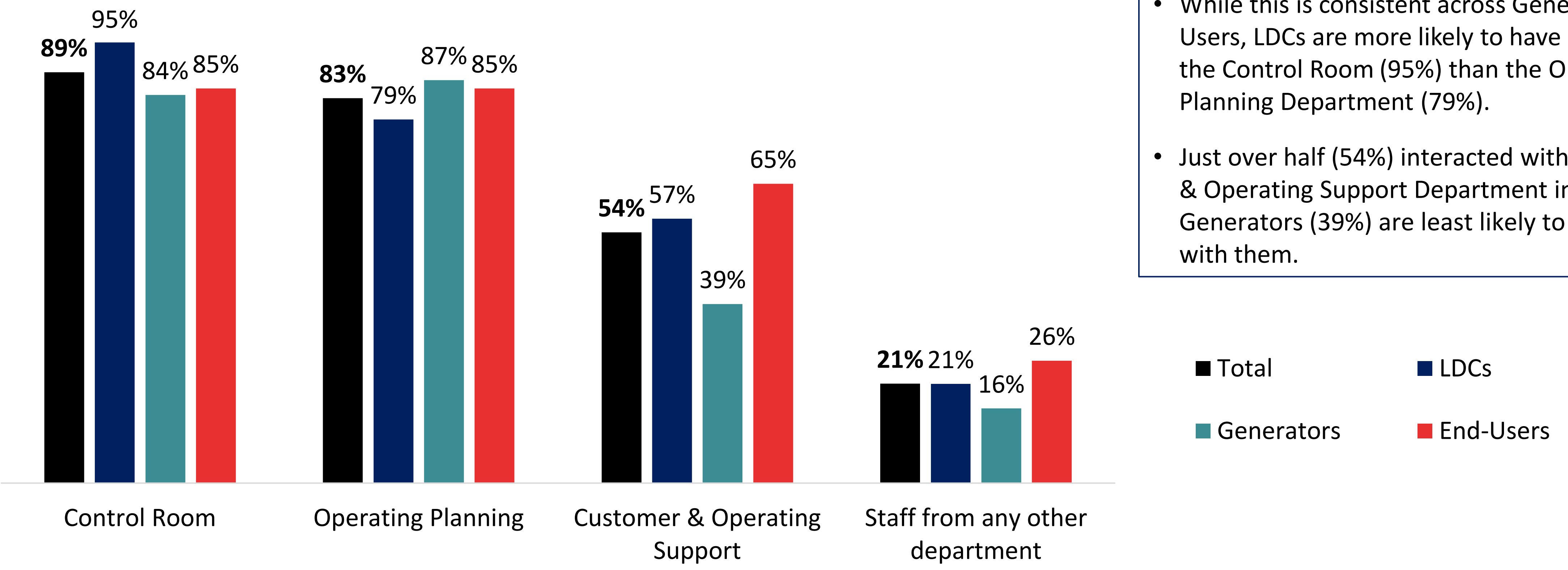
CSAT

- *Communication and Responsiveness* is the strongest driver of overall satisfaction with the service of the OGCC. This factor is a combination of day-to-day communications and responding in a timely manner.
- The level of knowledge of OGCC staff is almost as strong a driver as *Communication and Responsiveness*.
- The third driver is how easy it is to reach the correct contact at the OGCC.
- Being an End-User has a negative impact on overall satisfaction with the OGCC.

OGCC: Department Contact

Q

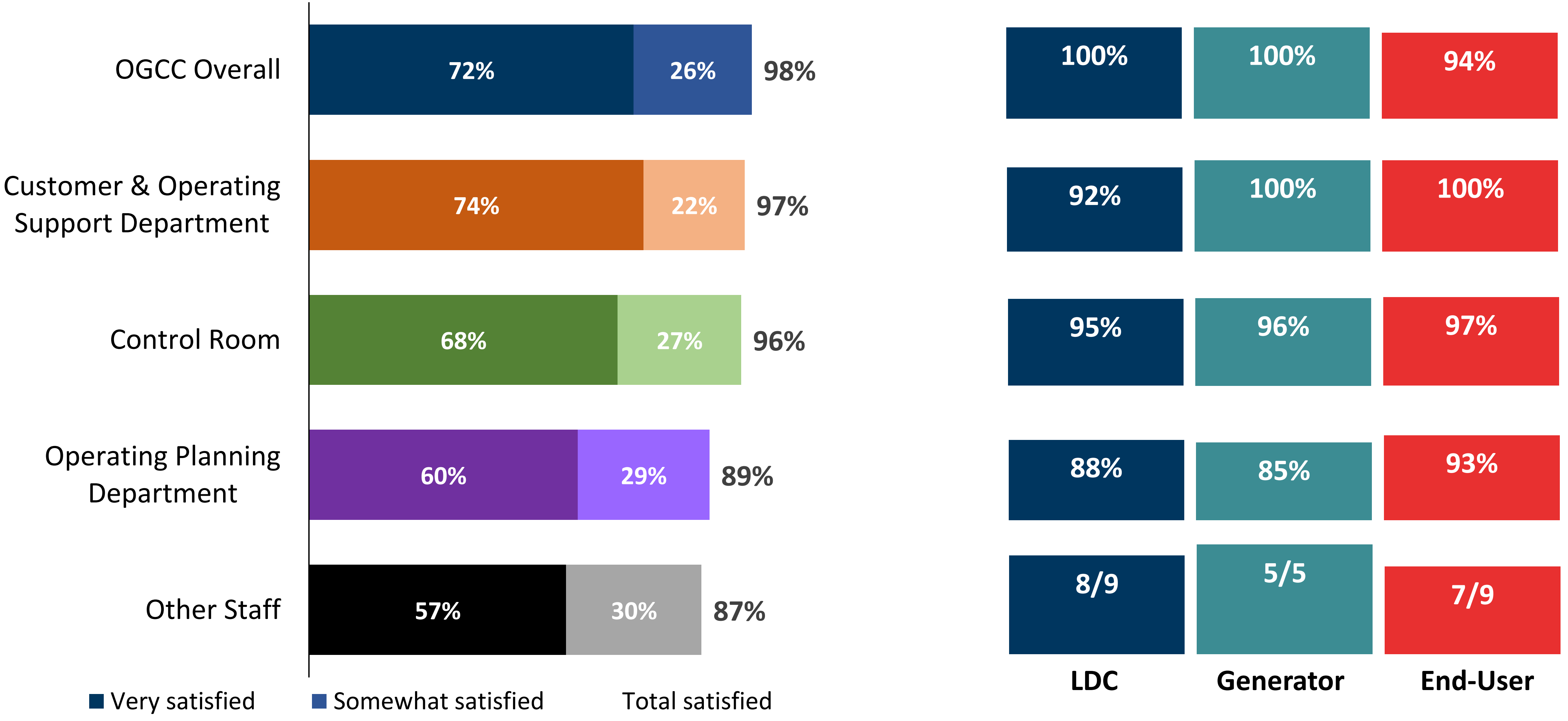
B1. Thinking about the past year, please indicate which of the following Departments at Hydro One's Ontario Grid Control Centre (OGCC) you have had contact with. This contact may have been initiated either by you or by someone at the OGCC.
[Asked of all respondents, multiple-mention, n=107]



Key Insights

- Over 8-in-10 interacted with the Control Room (89%) and/or the Operating Planning Department (83%) in the past year.
- While this is consistent across Generators and End-Users, LDCs are more likely to have interacted with the Control Room (95%) than the Operating Planning Department (79%).
- Just over half (54%) interacted with the Customer & Operating Support Department in the past year. Generators (39%) are least likely to have interacted with them.

Satisfaction: Overall satisfaction is highest for the OGCC overall and the Customer & Operating Support Department



Overall OGCC Customer Satisfaction

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OGCC Summary

Overall Satisfaction

Metrics Included:

Relationship with OGCC (96%)
Day-to-Day Communications (91%)
Knowledge of Staff (91%)
Responds in Timely Manner (89%)
Ease of Reaching Correct Contact (87%)
Understanding Business Needs (85%)
Sensitivity to Outage Impact (82%)

Overall Satisfaction	Overall Dissatisfaction
98%	1%

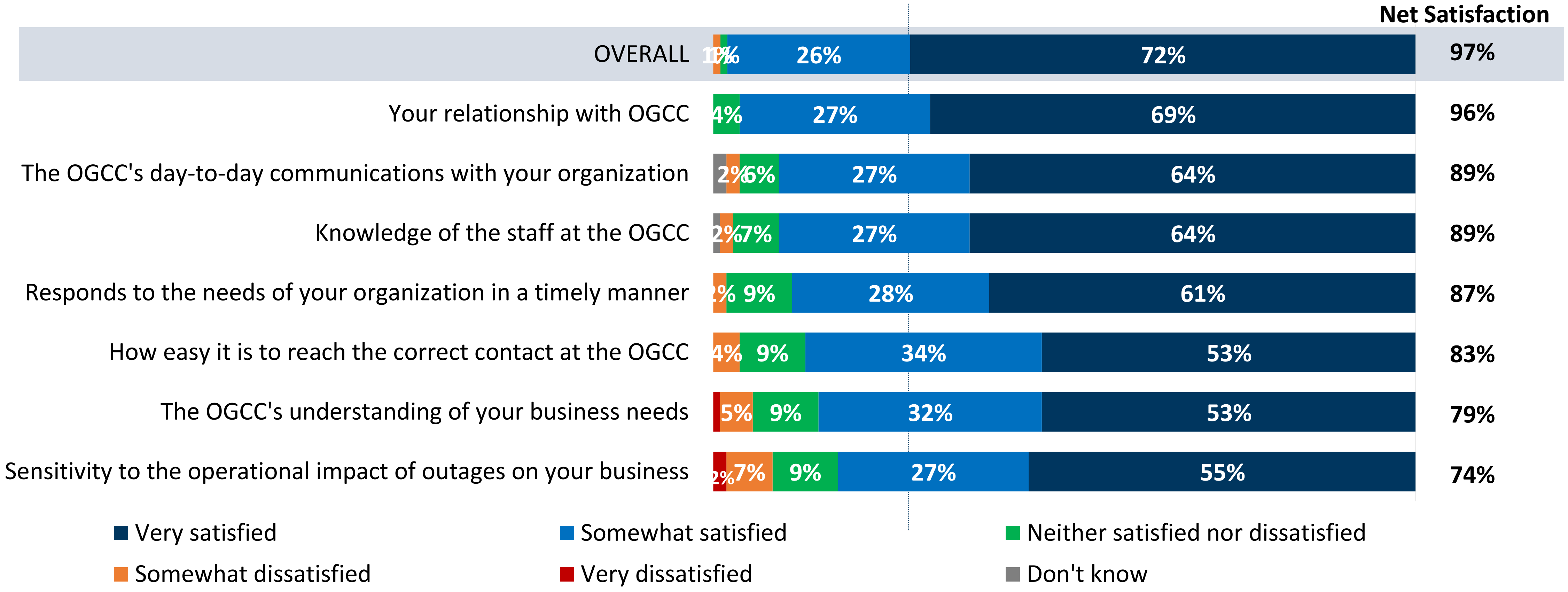
The following questions were asked of all respondents. [n=107]

Key Insights

- Almost all customers who have had contact in the past year are satisfied with the OGCC overall.
- More than three-in-five are *"very satisfied"* with their relationship with OGCC, day-to-day communications, staff knowledge and timeliness of response.
- End-Users are the only group to report being anything less than satisfied with the OGCC overall, but they are at least marginally satisfied than the other two customer groups on most of the individual metrics.
- There is some variation on which metric each customer type reports their lowest level of satisfaction:
  - LDCs: sensitivity to outage impact (81%)
  - Generators: understanding business needs and sensitivity to outage impact (both 77%)
  - End-Users: ease of reaching the correct contact (82%)

OGCC Performance Metrics: A majority are *“very satisfied”* with the OGCC’s performance on all aspects

Q In general, how satisfied or dissatisfied are you with the following aspects of Hydro One’s OGCC?
[Asked of all respondents, n=107]



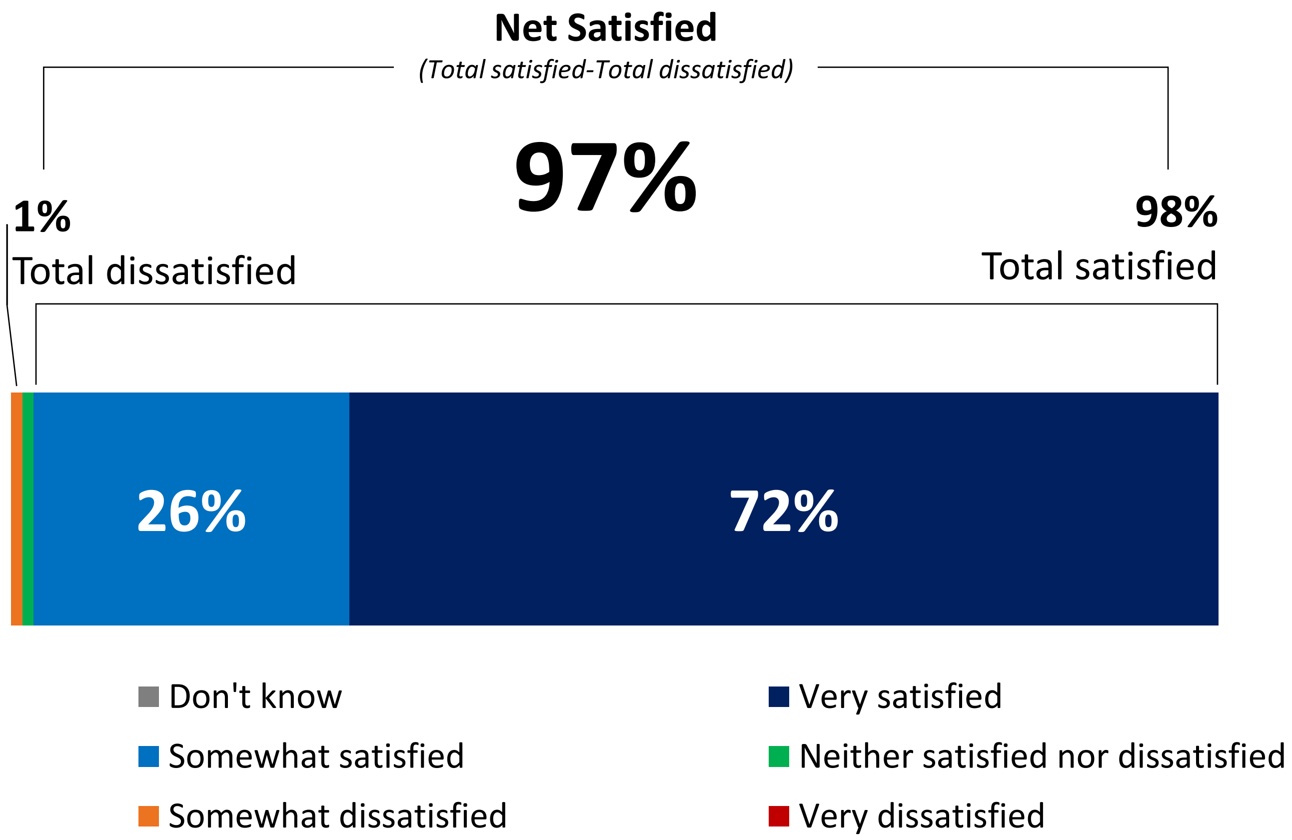
Key Insights

- All performance metrics have strong levels of satisfaction.
- Relationship with OGCC and day-to-day communications have highest net satisfaction.

Overall OGCC Satisfaction: Nearly three quarters (72%) are *"very satisfied"* with the OGCC; only 1% are *"somewhat dissatisfied"*

Q

C2. Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One's Ontario Grid Control Centre (OGCC)?
[Asked of all respondents, n=107]

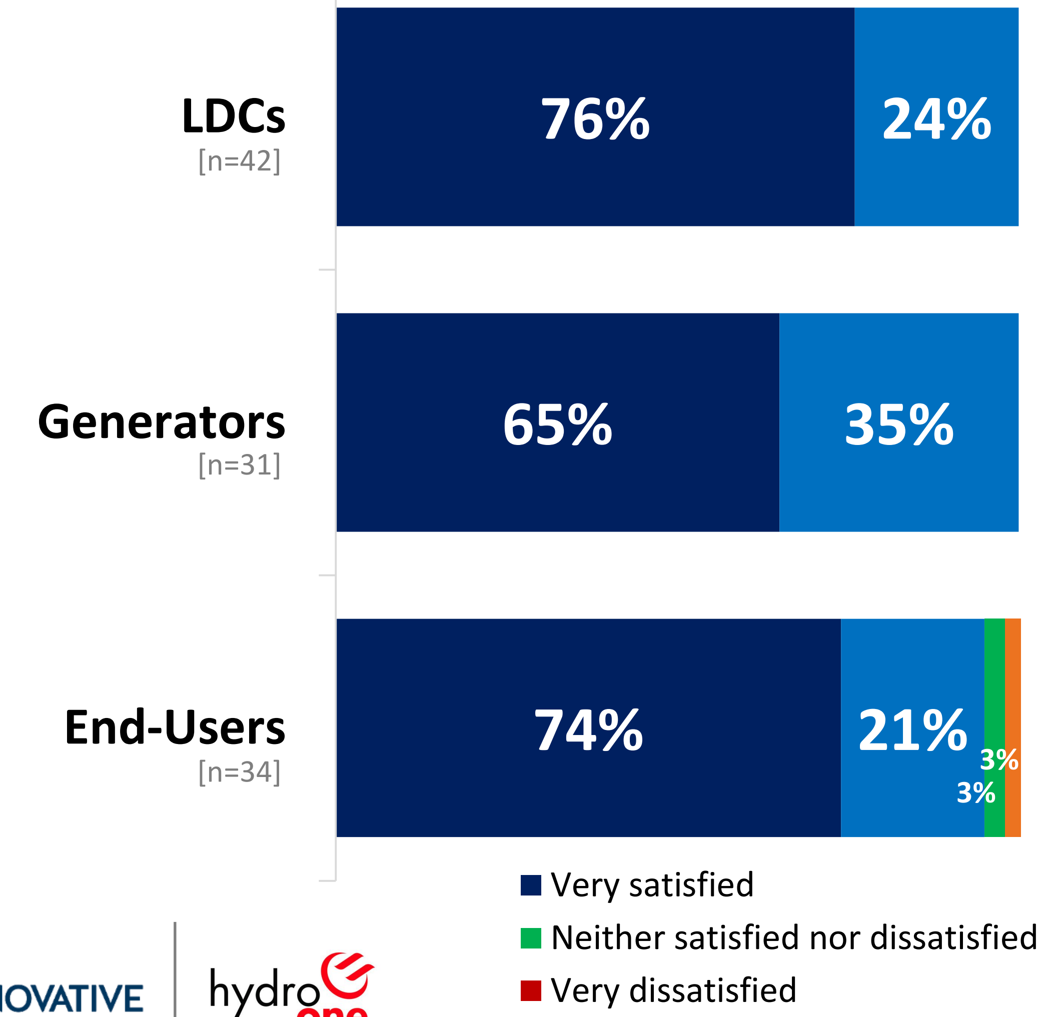


Key Insights

- The level of satisfaction with OGCC is overwhelmingly positive, with three quarters (72%) saying they are "very satisfied".

Overall Satisfaction | By Customer Type: 3-in-4 LDCs and End-Users are "*very satisfied*" with OGCC, about 10 points higher than Generators

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One's Ontario Grid Control Centre (OGCC)?
[Asked of all respondents, n=107]



	Total Dissatisfied	Total Satisfied	Net Satisfaction
LDCs	-	100%	+100%
Generators	-	100%	+100%
End-Users	3%	94%	+91%

Key Insights

- LDCs and End-Users are more intensely satisfied with OGCC overall than Generators, but there is a little bit (3%) of dissatisfaction among End-Users.

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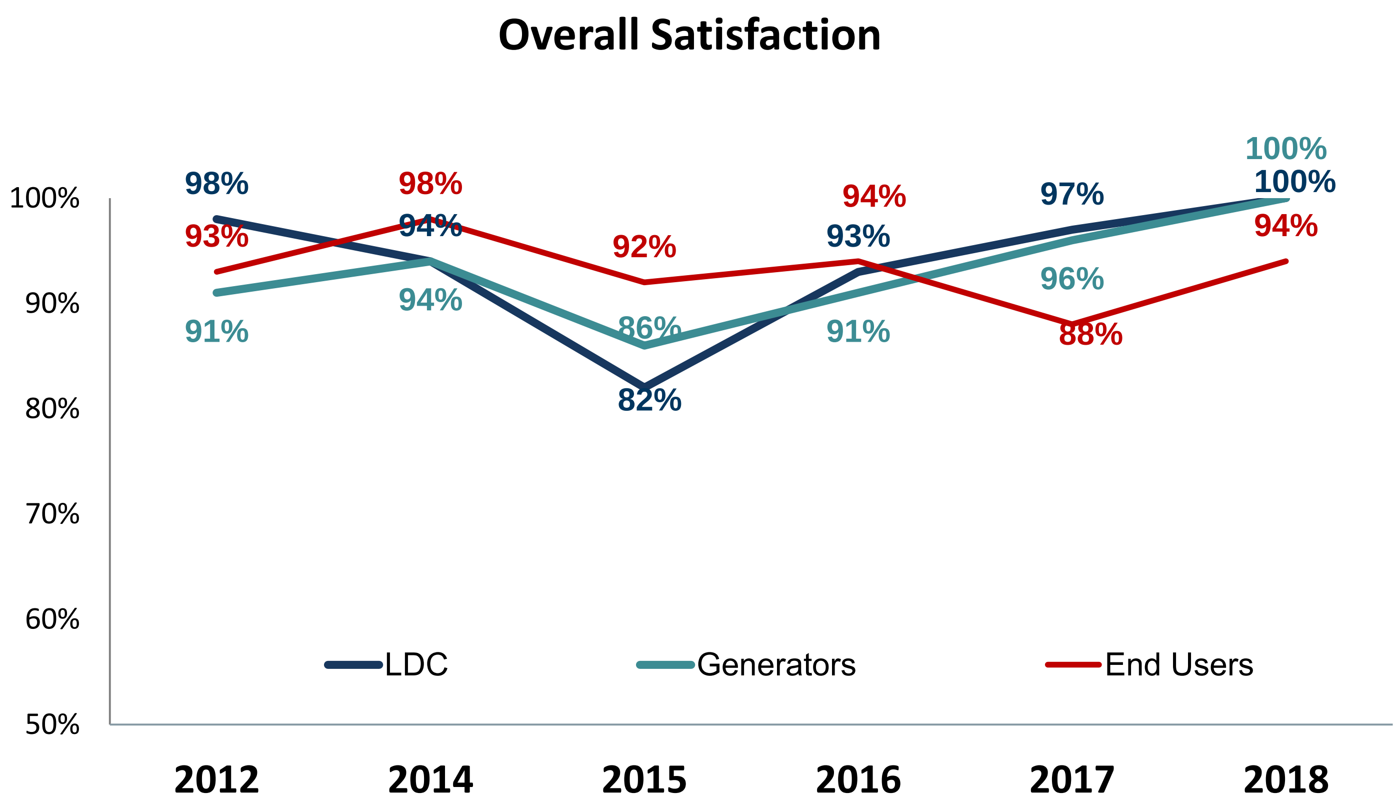
OGCC OVERALL

Overall Satisfaction | Tracking by Customer Type: At least marginal gains in overall satisfaction with OGCC across all customer types

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One's Ontario Grid Control Centre (OGCC)?

[Asked of all respondents, n=107]



Key Insights

- LDCs and Generators hit universal satisfaction for the first time since tracking began in 2012.
- The customer types have both been trending upward since 2015.
- End-Users have recovered from dip in satisfaction last year.

LTX Customer Type	Total Population	2018 Sample Size
LDCs	65	42
Generators	78	31
End-Users	74	34

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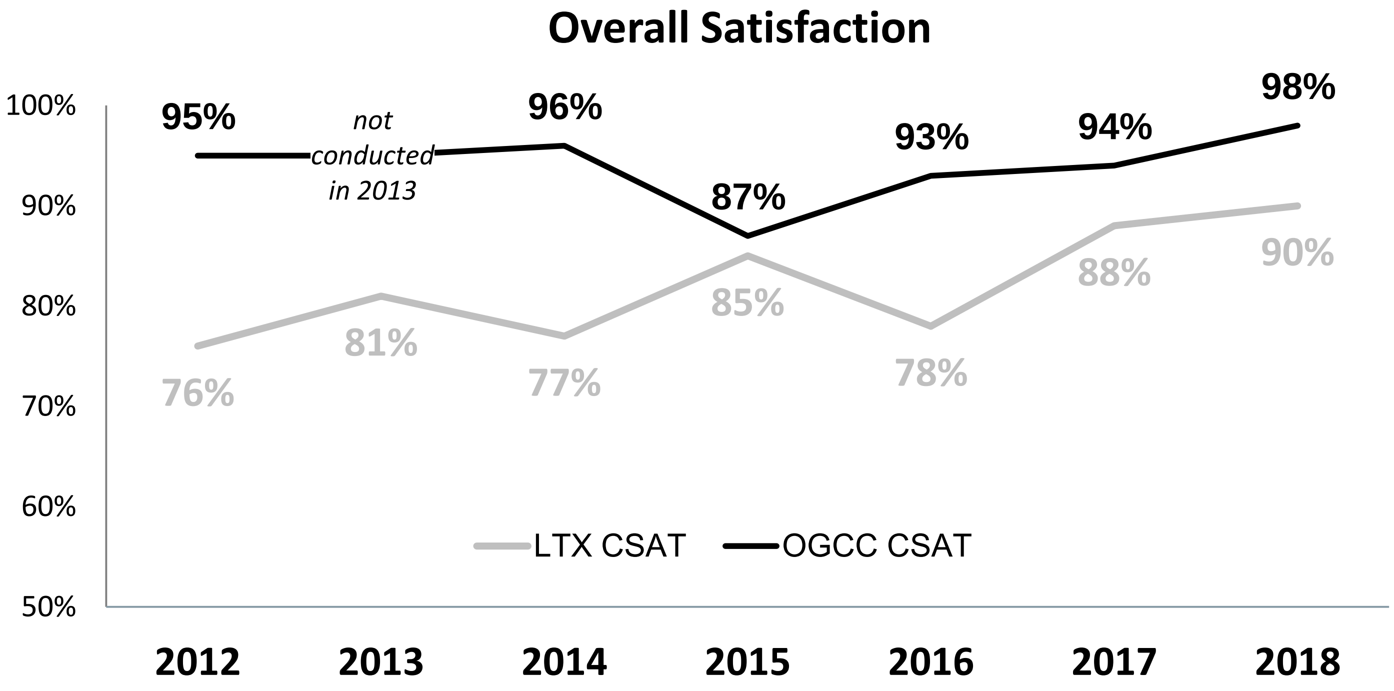
NOTE: Response "Don't know" (0% 2018) was excluded from this analysis in order to be consistent with previous methodology.
Survey not conducted in 2013.

Overall Satisfaction | LTX CSAT vs OGCC CSAT: Marginal widening of the gap between utility and OGCC satisfaction levels

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One's Ontario Grid Control Centre (OGCC)?
[Asked of all respondents, n=107]

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?
[Asked of all respondents, n=112; valid responses n=112]



Key Insights

- After narrowing the gap in 2015, satisfaction with the utility increased and has continued to trend upward since 2016.
- OGCC satisfaction dropped in 2016, bounced back in 2017 and improved marginally in 2018.

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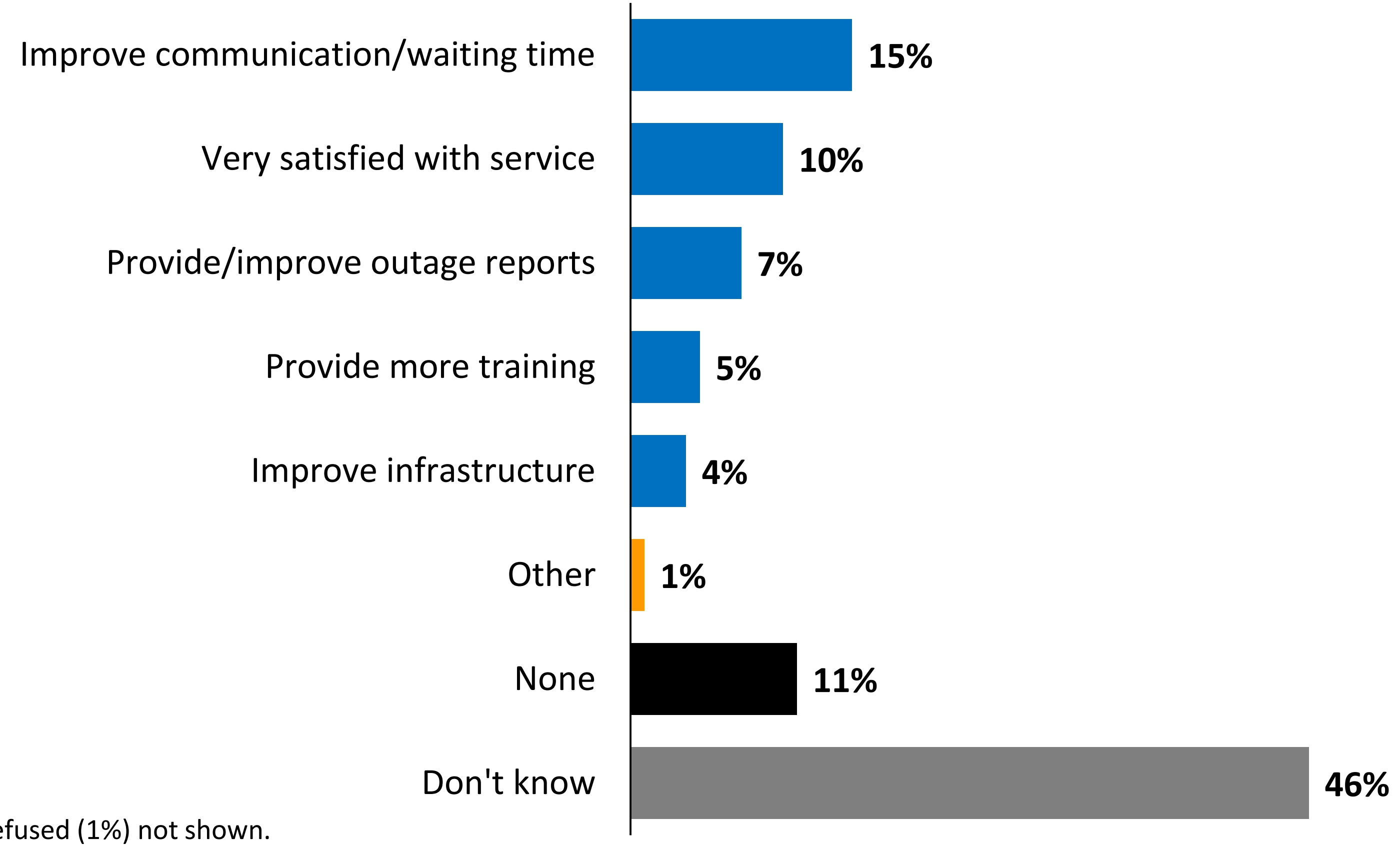
NOTE: Response "Don't know" (0% in 2018) was excluded from this analysis in order to be consistent with previous methodology.

Overall Areas of Improvement: Communication and waiting time lead suggested improvements; over half (57%) say nothing or don't know

Q

C3. Is there anything in particular that Hydro One's Ontario Grid Control Centre (OGCC) can do to improve its services to your organization?

[Asked of all respondents, open-ended, n=107]



NOTE: Refused (1%) not shown.

Key Insights

- More than half do not have any specific suggestions for improvements at OGCC.
- The most common suggestions are to improve communication/waiting time. Others would like improvements on outage reports, and for more training.

Relationship With OGCC: 7-in-10 (69%) are "*very satisfied*" with relationship; Generators (65%) are marginally less intensely satisfied

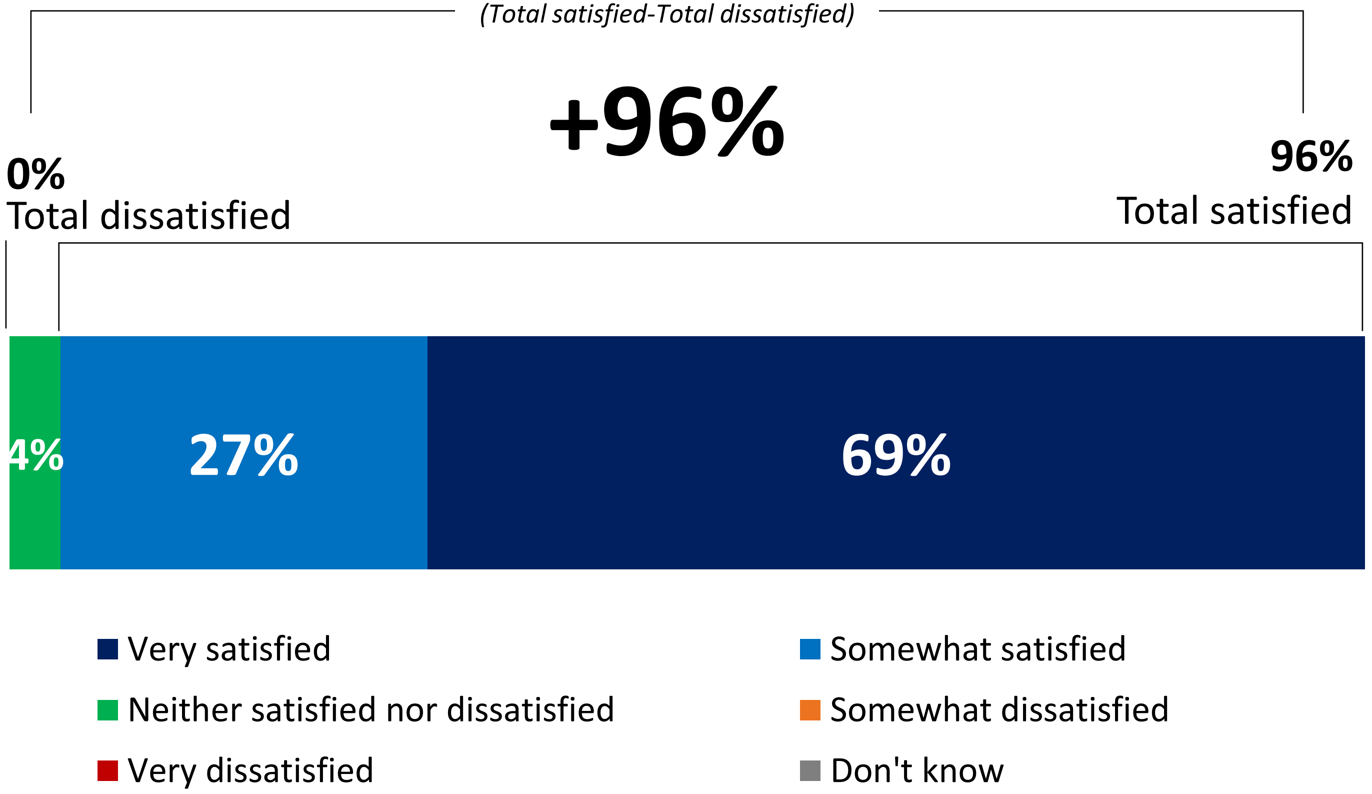
Q In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?

C4. Your relationship with OGCC

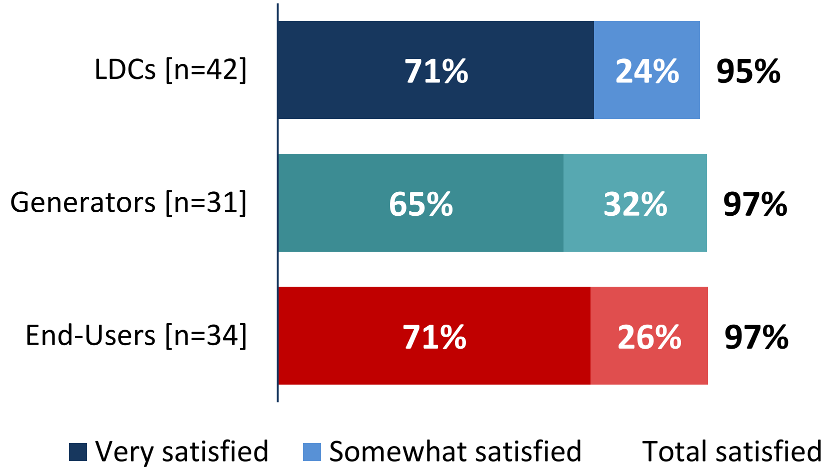
[Asked of all respondents, n=107]

Net Satisfied

(Total satisfied-Total dissatisfied)



Total Satisfaction ▶▶ By Customer Type



Key Insights

- While the total satisfaction levels with their relationship with OGCC are consistent across the customer segments, LDCs (71%) and End-Users (71%) are 6 points more likely to say they "very satisfied" than Generators (65%).

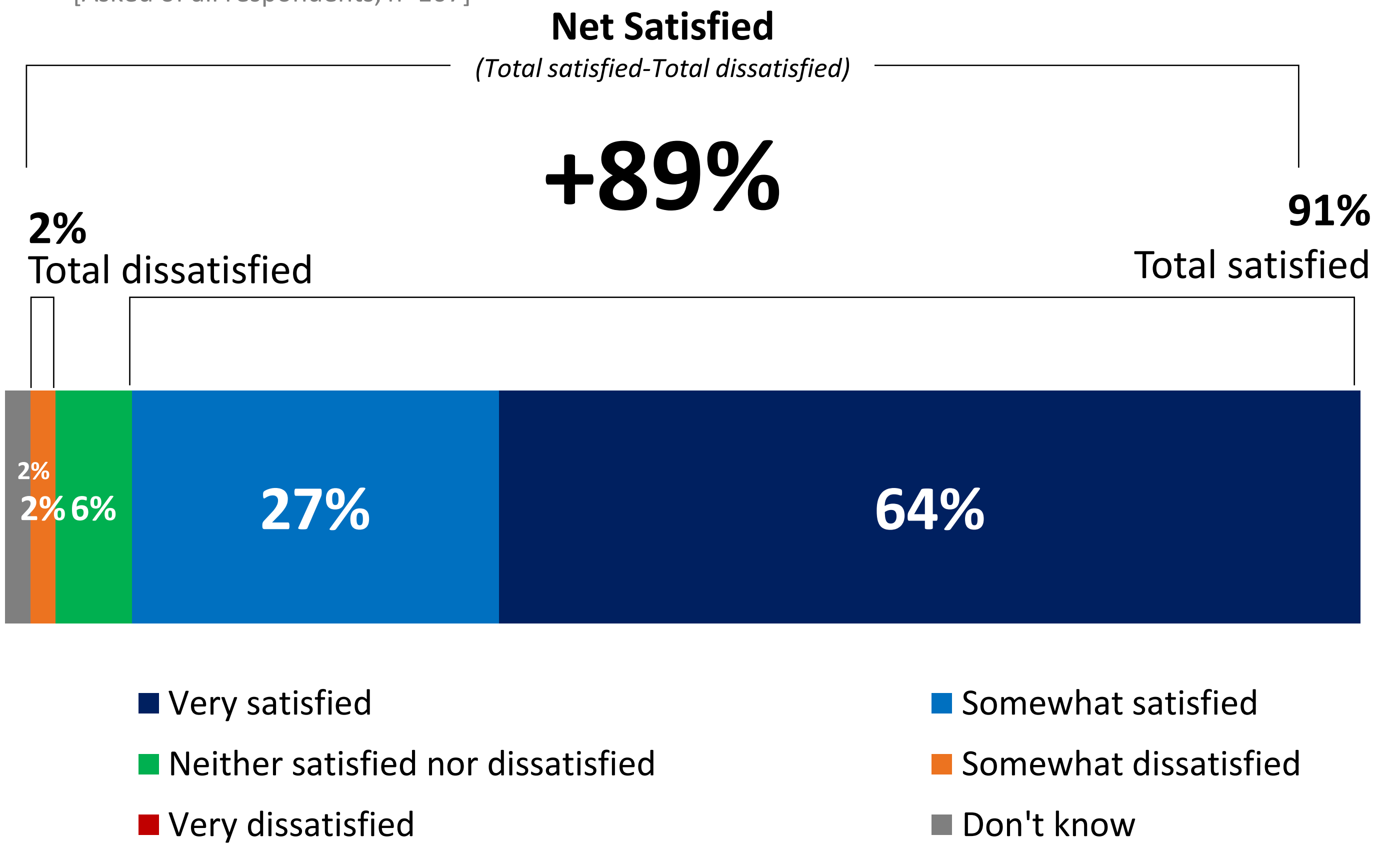
Day-to-Day Communications: Two-thirds (64%) are "*very satisfied*" with communications; higher among End-Users (71%)

Q

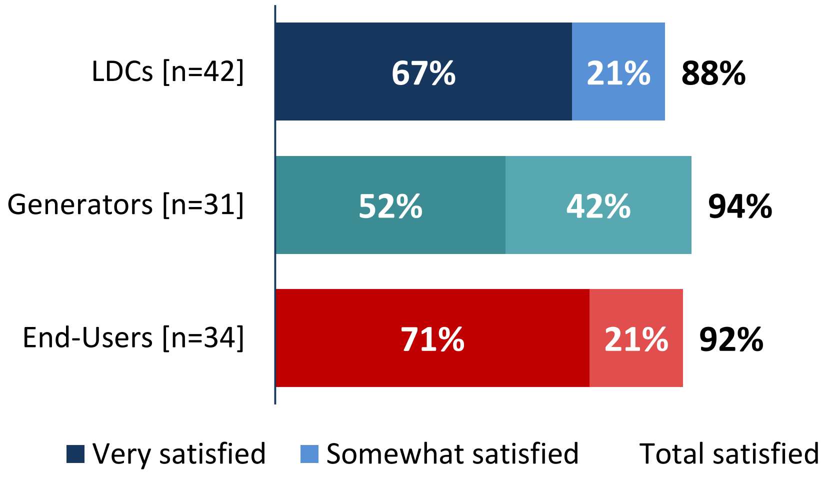
In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?

C5. The OGCC's day-to-day communications with your organization

[Asked of all respondents, n=107]



Total Satisfaction ▶▶ By Customer Type



Key Insights

- The proportion of LDCs (67%) and End-Users (71%) saying they are "very satisfied" with OGCC's day-to-day communications is 15+ points higher than among Generators (52%).

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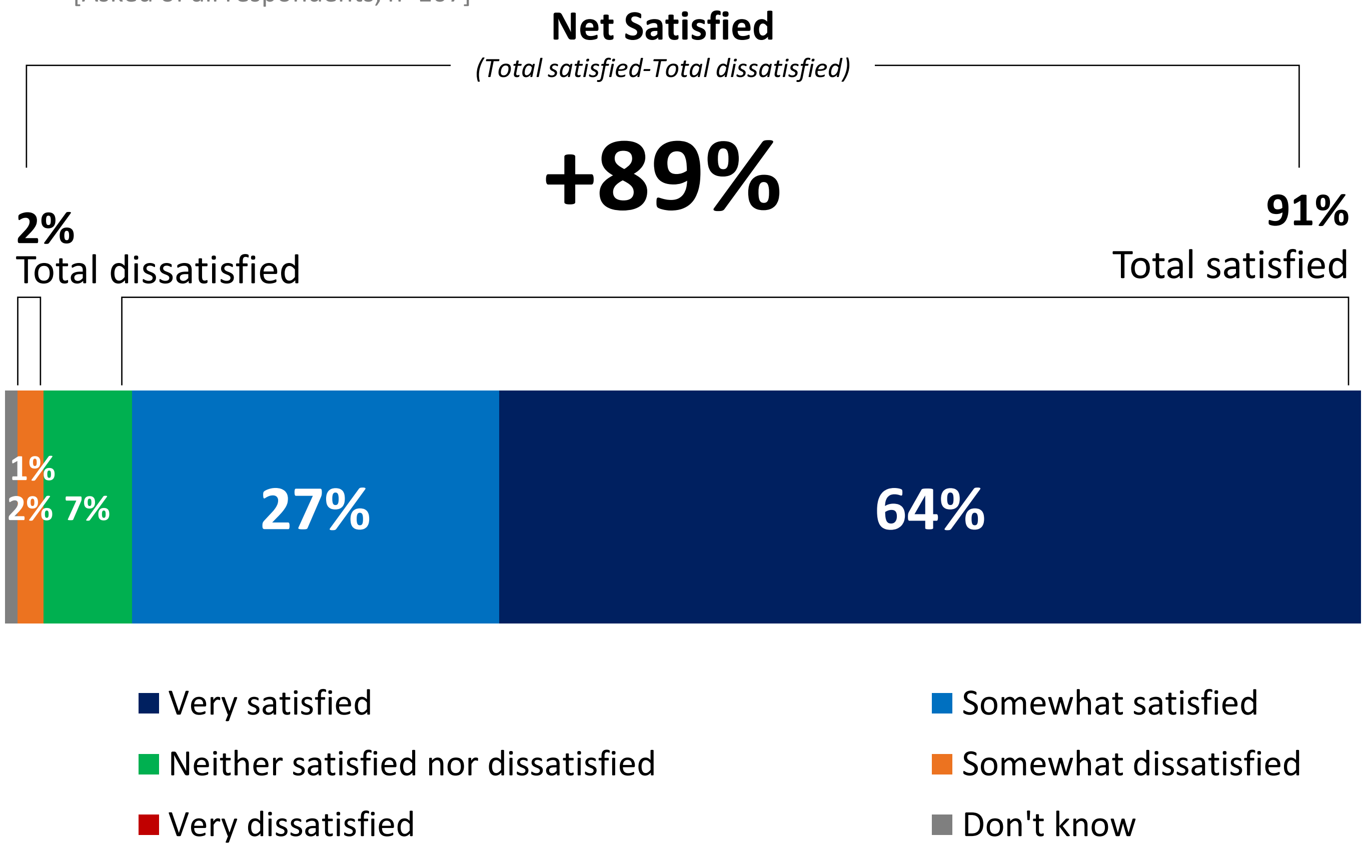
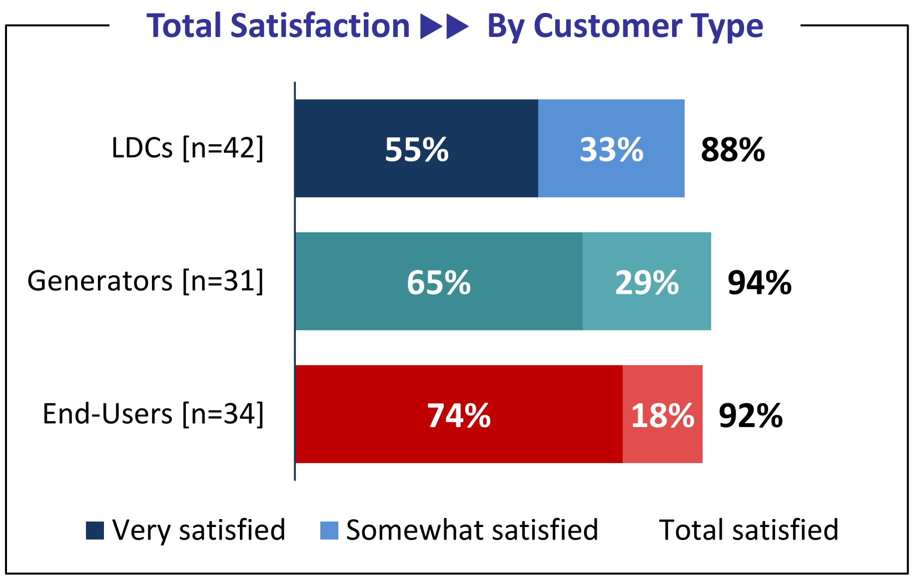
Staff Knowledge: Two-thirds (64%) respondents are "*very satisfied*" with knowledge of staff at the OGCC; highest among End-Users (74%)

Q In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?

C6. Knowledge of staff at the OGCC

[Asked of all respondents, n=107]



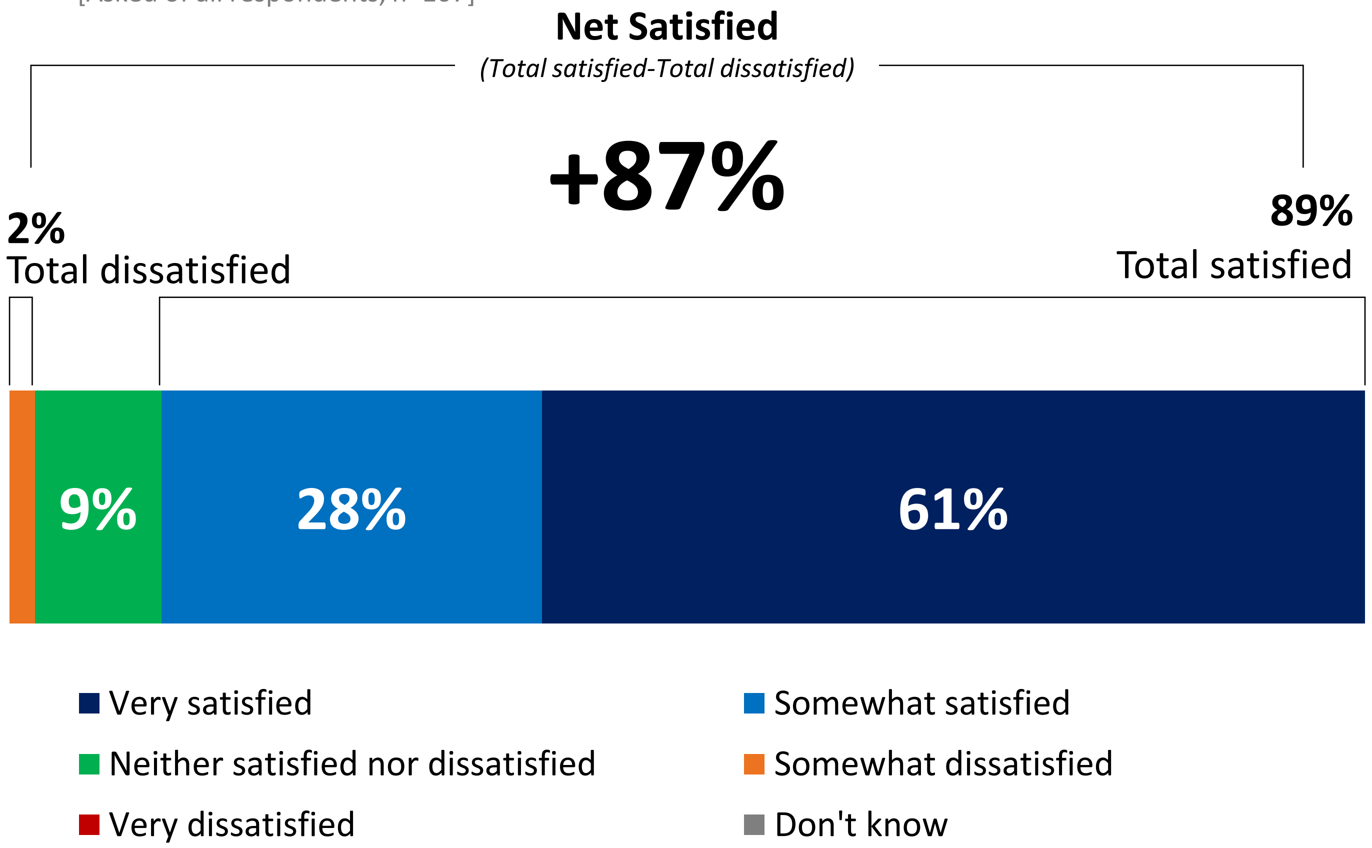


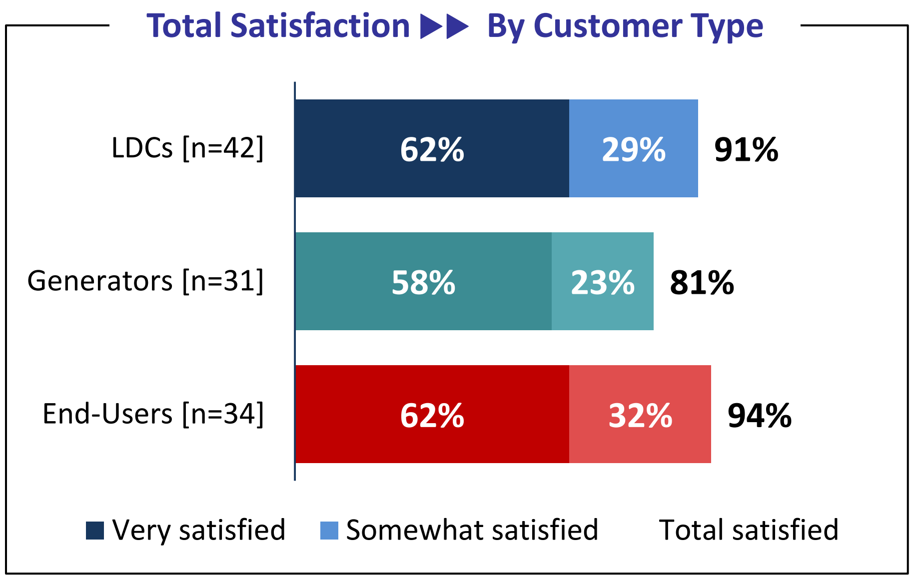
Key Insights

- The proportion of End-Users (74%) saying they are "very satisfied" with the knowledge of OGCC's staff is nearly 20 points higher than among LDCs (55%).
- The total level of satisfaction is marginally higher among Generators and End-Users than among LDCs.

Timely Response to Needs: 3-in-5 (61%) are "*very satisfied*" with the timeliness of response; Generators (58%) marginally lower than average

Q In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?
C10. The OGCC responds to the needs of your organization in a timely manner
[Asked of all respondents, n=107]





Key Insights

- About 3-in-5 are "very satisfied" with OGCC's timely responses to their needs. This is largely consistent across the three customer types.

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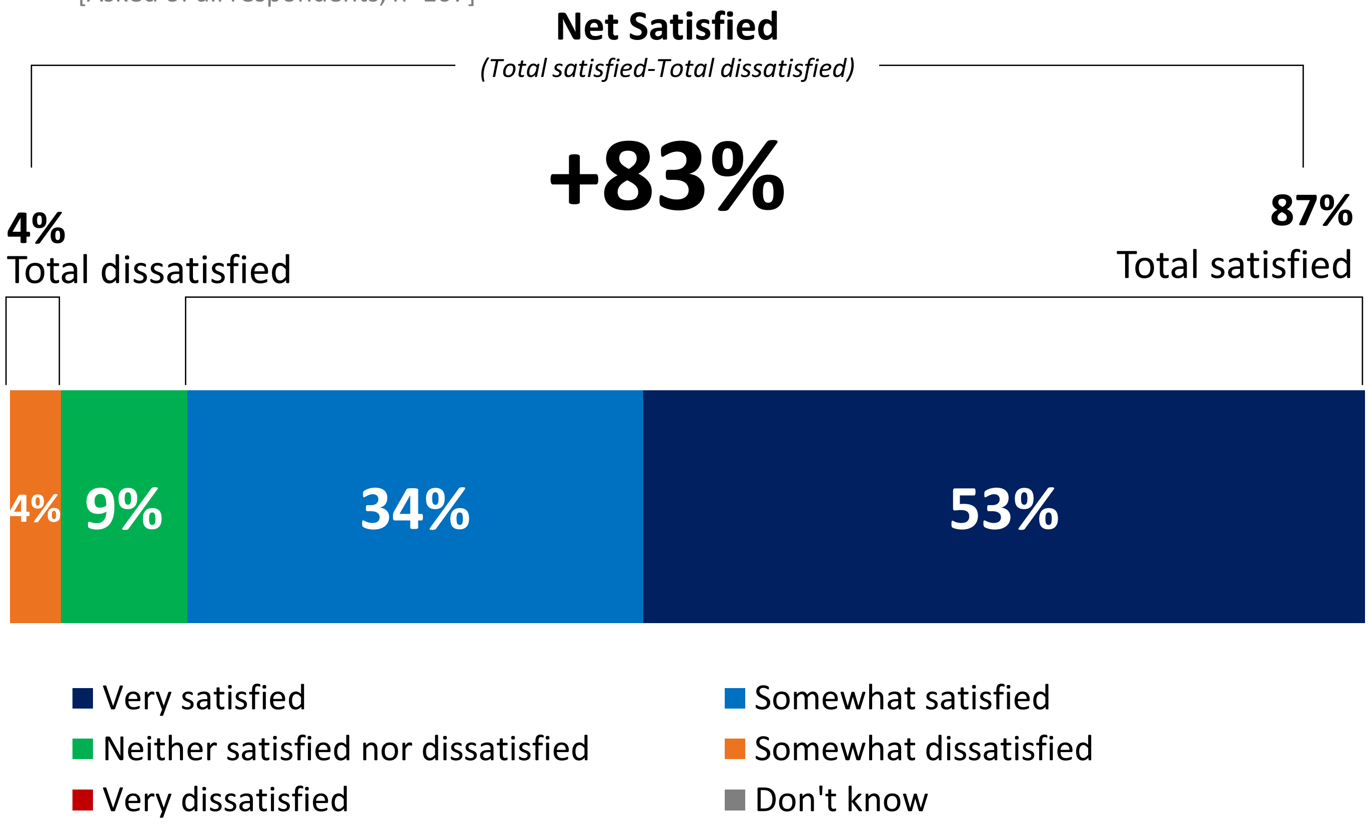
Reaching the Correct Contact: Over half (53%) are "*very satisfied*"; highest among LDCs (62%) and lowest among Generators (45%)

Q

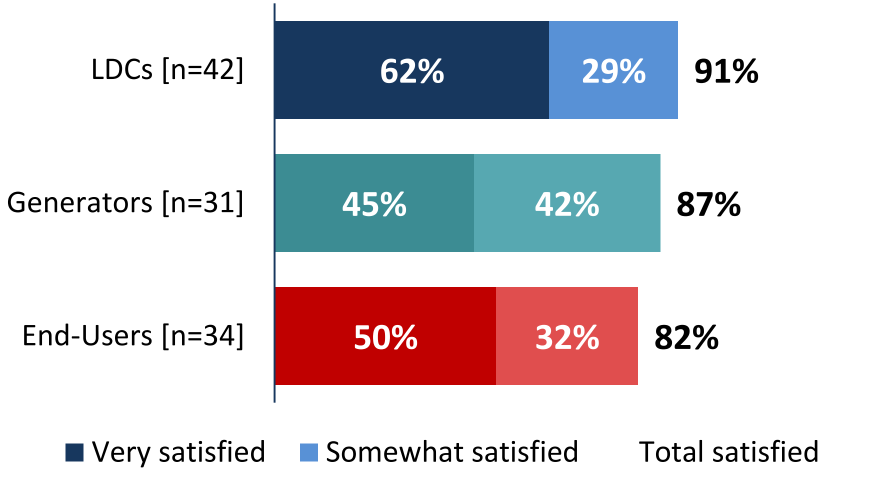
In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?

C8. How easy it is to reach the correct contact at the OGCC

[Asked of all respondents, n=107]



Total Satisfaction ▶▶ By Customer Type

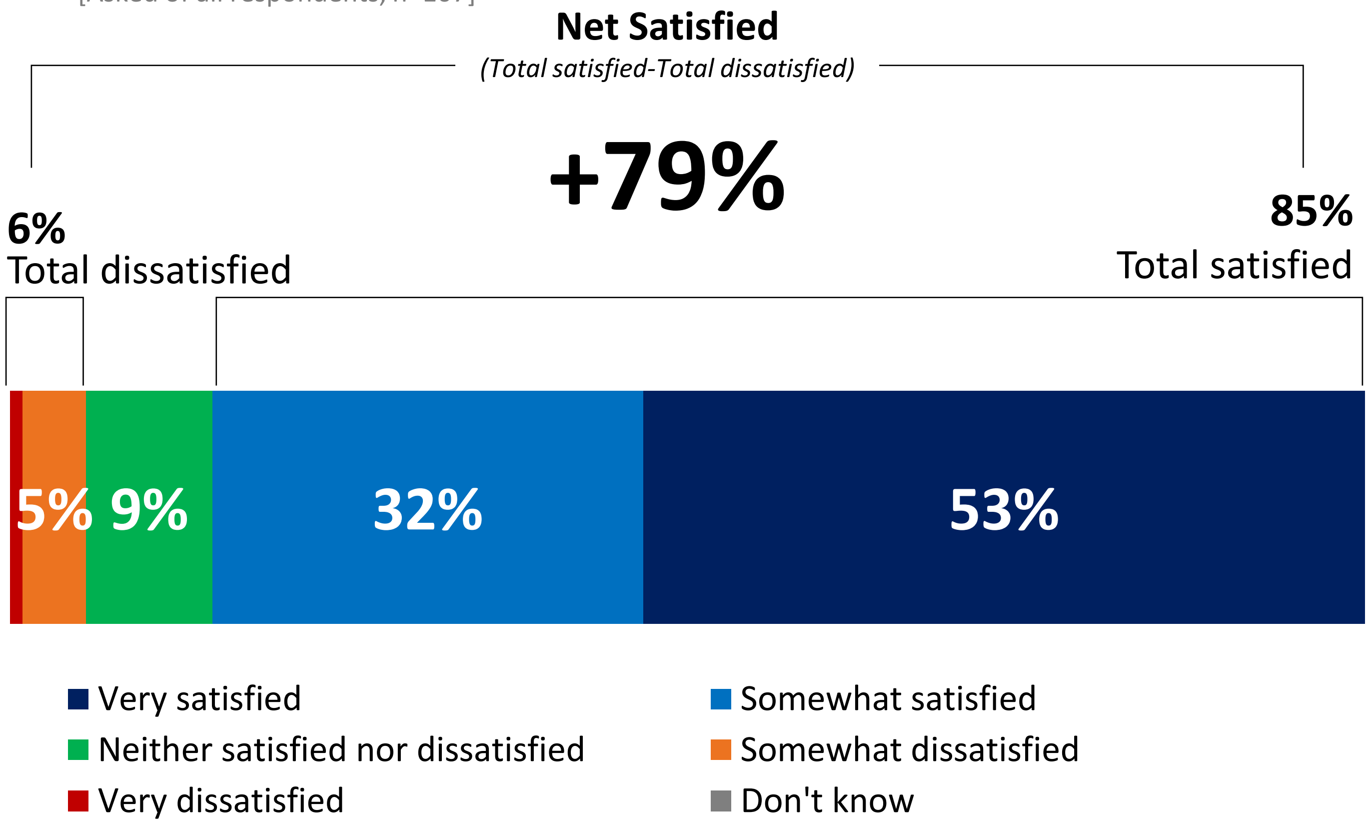


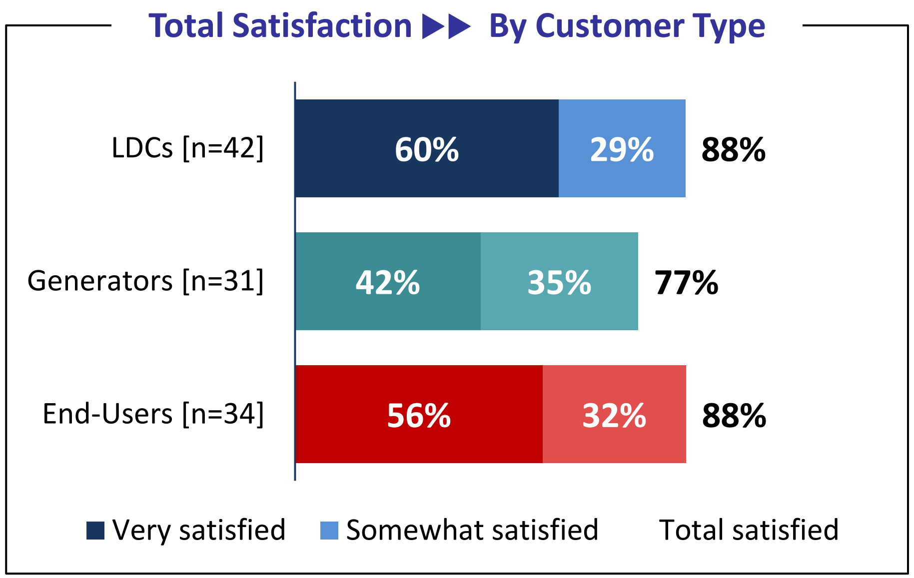
Key Insights

- The proportion of LDCs (62%) saying they are "very satisfied" with the ease of reaching the correct contact is 17 points higher than among Generators (45%).
- The level of intense satisfaction among End-Users (50%) on par with the average (53%).

Understanding Business Needs: Over half (53%) are "*very satisfied*" with OGCC's understanding of their needs; lowest among Generators (42%)

Q In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?
C9. The OGCC's understanding of your business needs
[Asked of all respondents, n=107]





Key Insights

- Intense satisfaction among End-Users (56%) and LDCs (60%) is 14 or more points higher than among Generators (31%).

Regression Analysis

Using Regression Analysis: *Identifying drivers of customer satisfaction*

What is Regression Analysis?

Regressions are another means of determining importance.

- A regression allows us to take all the questions that may explain a key question we are interested in and see which of these is the most important.
- Regressions do this by holding all the likely suspects constant and varying one question at a time to see which questions (explanatory variables) have the greatest impact on the key question (dependent variable).
- In this study, we use regression to understand **why some respondents rate their satisfaction with Hydro One's OGCC higher than others.**

We use ***Factor Analysis*** to explore underlying dimensions and structure the regression analysis.

- A factor analysis finds the true underlying dimensions of customer satisfaction that explain the pattern of responses to the larger set of attributes.
- Factor analysis allows us to find which attributes mean similar things to customers. The use of factor analysis allows us to determine which attributes should be grouped together in order to conduct meaningful analysis.

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Key Question (Dependent Variable): *OGCC Customer Satisfaction (CSAT)*

	OGCC CSAT
Key Question (Dependent Variable)	*"Overall, how **satisfied or dissatisfied** are you with the service your organization receives from Hydro One's Ontario Grid Control Centre (OGCC)?"*
Purpose of the question	Measures **overall satisfaction** towards the OGCC.

What drives overall satisfaction?

The Regression Model and Factor Analysis: *Identifying drivers of customer satisfaction*

We have identified two factors – "Business needs" and "Communications and Responsiveness". All other drivers are standalone explanatory variables.

Controls

- Customer Type

Interactions with OGCC

- Operating Planning Department
- Control Room
- Customer & Operating Support Department
- Staff from any other department

Unplanned Outage Experience

- Satisfaction with the management
- Satisfaction with the number of unplanned power outages

Planned Outage Experience

- Satisfaction with the management
- Satisfaction with the number of planned power outages

Satisfaction with Various Aspects of OGCC

- Their relationship with OGCC
- The OGCC's sensitivity to the operational impact of outages on their business
- The OGCC's understanding of their business needs

Factor: Business needs

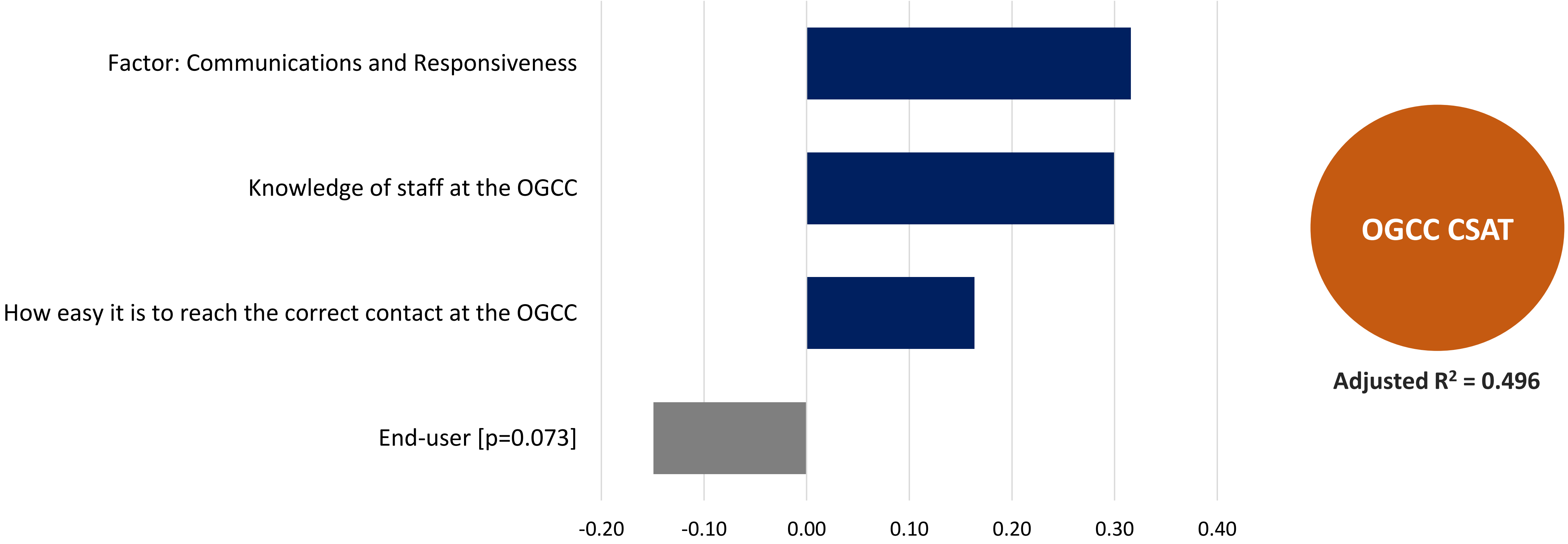
- The OGCC's day-to-day communications with their organization
- The OGCC responds to the needs of their organization in a timely manner

Factor: Communications and Responsiveness

- Knowledge of staff at the OGCC
- How easy it is to reach the correct contact at the OGCC

Regression Analysis: *Identifying drivers of customer satisfaction*

The strongest driver of customer satisfaction is *Communications and Responsiveness*. Many aspects of OGCC, such as knowledge of staff and the ease of reaching the correct contact, also have statistically significant impacts on customer satisfaction.



NOTES: Factor ***Communications and Responsiveness*** combines "the OGCC's day-to-day communications with their organization" and "the OGCC responds to the needs of their organization in a timely manner".
Chart shows standardized beta scores. All drivers significant at a 95% confidence interval unless indicated otherwise.

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For more information, please contact:

Jason Lockhart
Vice President

416-642-7177
jlockhart@innovativeresearch.ca

Susan Oakes
Vice President

416-642-6341
soakes@innovativeresearch.ca

Andrea Nuesser
Senior Consultant

416-640-4134
anuesser@innovativeresearch.ca

1.4 (5.2.3, 2.4.3) PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT: BENCHMARKING AND OTHER STUDIES

Benchmarking studies and third party assessments help inform Hydro One of the condition of its assets and how to effectively and efficiently manage those assets. To support this Application, Hydro One has commissioned the following third-party studies:

- Results of PTX Analysis of Hydro One's Transformer Fleet;
- Derivation of Transmission Substation Transformer Hazard Functions;
- Derivation of Circuit Breaker Hazard Functions;
- Derivation of Overhead Conductor Hazard Function;
- Operating Spare Transformers Requirement Assessment;
- Expected Service Life Survey of Transformers and Circuit Breakers;
- Expected Service Life Assessment of Specific Relays;
- Expected Service Life Assessment of Specific Underground Transmission Cables;
- Review of Utilities' Management of Air Blast Circuit Breakers;
- Review of Utilities' Management of Oil Circuit Breakers;
- Degradation Rates of Steel Tower Coating Systems;
- Polymer Insulator Population Assessment;
- Phase 2: Canadian Porcelain/Canadian Ohio Brass Porcelain Insulator Population Assessment;
- Review of Hydro One's Capabilities in Transmission Asset Analytics and Reliability Risk Modelling;
- Investment Planning Process Review;
- Line Loss Assessment;
- Total Factor Productivity and Econometric Total Cost Benchmarking Study; and
- Compensation Cost Benchmarking Study.

The first fifteen of the above-listed third-party studies are discussed in TSP Section 1.4.2, below. The remaining three third party studies correspond to other aspects of the Application and are discussed elsewhere, as indicated below:

- The Line Loss Assessment is discussed in TSP Section 1.8;
- The Total Factor Productivity Study and Econometric Total Cost Benchmarking Study is discussed in Exhibit A, Tab 4, Schedule 1; and
- The Compensation Cost Benchmarking Study is discussed in Exhibit F, Tab 4, Schedule 1.

1.4.1 (5.3.2 C, 2.4.3) BENCHMARKING OVERVIEW

Hydro One's Application and transmission system plan are supported by benchmarking reports prepared by independent consultants. This section provides background on the consultants. Summaries of the studies, including their purpose, methodology, findings and significance for Hydro One's capital expenditure plan and its Application are included in Section 1.4.2 of this Exhibit. Summaries of the technical findings of the studies are provided in Section 1.4.3 and copies of the studies are included as Attachments in Section 1.4.4. The focus is on benchmarking and other studies related to asset condition and asset management.

1.4.1.1 BENCHMARKING AND OTHER STUDY CONSULTANTS

Electric Power Research Institute ("EPRI"), Kinectrics, Metsco Energy Solutions Inc. ("Metsco"), and the Boston Consulting Group ("BCG") assisted with Hydro One's benchmarking and asset condition and management process objectives as described herein.

Electric Power Research Institute

EPRI is an independent, non-profit organization that researches electricity generation, delivery and utilization to enhance quality of life by making electric power safe, reliable, affordable, and environmentally responsible. EPRI was originally created as a result of the Great North Eastern Blackout in November 1965 that left 30 million people in the United States without power. EPRI has established a strong reputation within the energy sector as a leading research and development organization that provides thought leadership, industry expertise, and collaborative value to help the electricity sector identify issues, technology gaps, and broader needs that can be addressed through effective research and development programs for the benefit of society. Its membership represents approximately 90% of the electric utility revenue generated in the United States and extends to participation in more than thirty five countries.

Kinectrics

Kinectrics is an independent testing, inspection, certification and consulting company based in Toronto. Kinectrics focuses on the development and application of advanced technologies for the power industry. Kinectrics serves the energy sectors in Canada, the United States and internationally, with twenty five unique laboratory and testing facilities, expertise built on over 100 years of experience, and over 400 engineers and technical experts.

Metsco Energy Solutions Inc.

Metsco is a Canadian corporation that has provided services to international electric utility clients focused on improving operating efficiency, financial performance and power system asset management since 2006. Metsco has experience in fields such as asset data analysis, failure curves, reliability analysis and reliability projections which has allowed them to become well-versed with the various methodologies, challenges, and strengths that exist in the industry. They have worked on developing health index formulations for the Centre for Energy Advancement through Technological Innovation to connect health indices to failure probabilities and risk assessment to drive investment decisions. Metsco's experts are recognized pioneers in the field of asset management, having been part of the founding committee of the health index methodology for asset risk assessment.

Boston Consulting Group

The Boston Consulting Group ("BCG") provides analysis of process management, capital planning, and the utility industry. BCG is a leading global consulting firm with over 14,000 employees and 90 offices in 50 countries. BCG has completed more than 2,500 energy cases in the past five years and has worked with fifteen of the twenty-five largest global utilities. Senior BCG leadership with extensive experience in utility operations, utility capital planning, and large capital project management globally and in Canada conducted the review of in support of this Application. The team also consisted of executing team members with significant experience in regulated utility operations and regulatory strategy in the US and Canada, including in Ontario.

EPRI, Kinectrics, Metsco, and BCG are reputable organizations with established track records of producing high quality, fact-based, technical deliverables. This is the reason why Hydro One had chosen them to perform the benchmarking and other studies described below.

1.4.2 (5.3.2 C, 2.4.3) SUMMARY OF BENCHMARKING AND OTHER STUDIES

In its Decision and Order in Hydro One's EB-2016-0160 proceeding, the OEB found that "Some of the elements that require more focus include a consistent, comprehensive asset condition assessment process which directly links to the Transmission System Plan ("TSP") and the capital investment plan; an appropriate pacing of capital expenditures that achieves a proper balance of need and rate impact." Hydro One engaged third party experts to perform a series of studies and reviews on specific assets and their treatment to determine whether Hydro One is following industry best practices for condition assessments, asset management and capital expenditure pacing. Hydro One is using the findings and recommendations from these studies to improve its processes.

The benchmarking and other studies described below demonstrate that Hydro One's practices and processes for managing its key transmission assets are aligned with industry best practices. In two areas; underground cables and overhead conductor, the study results recommended Hydro One increase its expected service life ("ESL") for these assets. Hydro One will review its management practices and decision making procedures to minimize life-cycle costs and more effectively manage risk for these assets based on these recommendations. However, as asset replacements in Hydro One's business plan are selected based on end of life of the asset, this has not impacted the current business plan.

BCG's Investment Plan Process Review results confirm that overall, Hydro One has implemented a consistent, thorough planning process that meets or exceeds expectations for a typical utility planning process in all areas. Metsco found that across the categories of their assessment, and in consideration of their utilization relative to other analytical and diagnostic tools comprising Hydro One's process, both Asset Risk Assessment ("ARA") and Asset Analytics ("AA"), are comparable to other asset management frameworks found elsewhere in the industry, and are sufficiently rigorous and robust to accomplish their intended tasks from an analytical perspective. Both ARA and AA are predominantly in line with advanced industry practices, with certain analytical elements approaching best-in-class capabilities.

Metsco reviewed the Reliability Risk Model ("RRM") and found that the analytical underpinnings and functionalities of the RRM trail advanced industry system reliability practices where used in asset management. In making this observation, Mestco found that a number of utilities do not nor have not until recently attempted to formally forecast system reliability in a comprehensive manner and suggests the RRM reflects continuous improvement in this area. However, as Hydro One uses the RRM as a customer communications tool to convey directional changes to reliability risk levels across spend scenarios, Metsco is of the view that the observed gaps pose no meaningful risks from an asset planning perspective. Hydro One must remain clear about the tool's purpose and the implications of its analysis.

The overall results of these studies demonstrate that Hydro One optimizes the life cycles of its assets and selects the appropriate assets for replacement in the Business Plan. This shows that Hydro One is well positioned to provide value to customers.

The technical findings from the studies are provided in Section 1.4.3, below. TSP Section 3.2.4 describes how Hydro One's proposed capital expenditure plan reflects the results of these studies/assessments.

1.4.2.1 RESULTS OF PTX ANALYSIS OF HYDRO ONE'S TRANSFORMER FLEET

Assessing the condition of in-service equipment accurately and efficiently is a critical step in asset management. In the context of a transmission system, there is no equipment for which this is more important than power transformers. Hydro One engaged EPRI to assess the condition of its transformers using the PTX analysis program. EPRI developed the PTX methodology for assessing the condition of transformers by analyzing dissolved gas data from a utility's historical oil data records. PTX identifies transformers with abnormal test results that are then subject to further consideration as to whether more detailed testing or increased monitoring is warranted. The resulting report from EPRI provides an overview of the PTX methodology and presents the results of its analysis for those of Hydro One's transmission system transformers for which data was provided.

In the report, the results are classified by primary voltage class and vintage and have been categorized into five condition risk rankings.

The results obtained by EPRI using its PTX tool are closely aligned with the results of the condition assessment methodology that Hydro One currently uses. This confirms that Hydro One's transformer condition assessment practices are aligned with industry best practices. More particularly, 80.5% of the asset condition assessments for Hydro One's transmission transformer fleet aligned with EPRI's PTX analysis based on dissolved gas in oil content and oil quality data. For the remaining 19.5% of assessments, the results of which were not well aligned, the majority of the differences are attributed to data issues such as oil cross contamination between tap changer and main tank oil. Hydro One depends on the subject matter experts to account for these issues. Therefore, Hydro One will continue its current practices and will track and monitor future test results.

1.4.2.2 DERIVATION OF TRANSMISSION SUBSTATION TRANSFORMER HAZARD FUNCTIONS

While Hydro One focuses on asset health including factors such as condition, criticality, reliability, and cost for asset replacement decisions, the mean life expectancy of equipment fleet is a key requirement for long term planning. It informs resourcing requirements, outage coordination, rate impact, and long term project schedules from planning to execution of work. Insights on fleet mean life expectancy may be derived from careful analysis of historical replacement data. The report arising from this study describes EPRI's efforts to model and develop transformer removal rates from historical replacement records and apply them to forecast the number of transformers expected to require replacement based on past practices. The purpose of the study is to develop transformer removal rates from historical replacement records and apply them to forecast the number of transformers expected to require replacement based on past practices.

Using Hydro One's transformer retirement data, EPRI modeled the transformer removal functions and has forecasted probable transformer replacement rates for the next 5 years.

This study confirms that Hydro One's pacing of transformer replacements is aligned with EPRI's forecast based on industry best practices. Hydro One will therefore continue its current pacing forecast to sustain its transformer fleet.

1.4.2.3 DERIVATION OF CIRCUIT BREAKER HAZARD FUNCTIONS

This report describes EPRI's efforts to model and develop circuit breaker removal rates from historical replacement records and apply them to forecast the number of circuit breakers expected to require replacement based on past practices.

EPRI has developed a methodology using advanced statistical techniques for analyzing circuit breaker (of all types) historical removals and applied it to Hydro One's circuit breaker fleet. Using Hydro One's circuit breaker retirement data, EPRI modeled Hydro One's circuit breaker removals and has forecast probable future removal rates.

This study confirms that Hydro One is replacing younger power circuit breakers at a rate expected from the Weibull model due to failures. However, older vintages of circuit breakers are being replaced at a quicker rate than expected.

Hydro One's volume of replacement over the plan period is higher primarily due replacement criteria that were not included in the EPRI report. These criteria include obsolescence concerns, safety concerns (e.g. lack of or insufficient arc resistance rating), change in system conditions (e.g. short circuit level), polychlorinated biphenyl ("PCB") mitigation per regulatory requirements and integrated investments. Further details on the reasons can be found in Section 3.2.4 of the TSP.

1.4.2.4 DERIVATION OF OVERHEAD CONDUCTOR HAZARD FUNCTION

This report describes EPRI's efforts to develop a conductor hazard curve and its ESL which can be used to project expected replacement needs for planning purposes.

The results of this study based on current condition assessment data and historical overhead conductor replacement data, indicate that ESL for overhead conductors in the Hydro One transmission system should be approximately 90 years. Hydro One's assigned ESL for overhead conductors was set at 70 years before this study. The new ESL resulting from this study does not affect the current business plan as identified replacements are not age based decisions, they are based on verified asset condition..

1.4.2.5 OPERATING SPARE TRANSFORMERS REQUIREMENT ASSESSMENT

The purpose of this study is to verify that Hydro One's spare transformer requirements are appropriate and consistent with industry best practices. Hydro One uses the Markov Model to determine the appropriate number of spare transformers required to ensure continuity of electricity supply to customers, safety and reliability. The Markov Model takes into consideration the probability of failure, carrying costs and procurement lead time to determine the most cost-effective number of spares to be kept in inventory. EPRI has developed analytics to optimize the power transformer spares practice which was compared with Hydro One Markov modeling.

This study confirms that Hydro One’s Operating Spare Transformer Strategy aligns with industry best practices. Hydro One will continue these practices and will continue to monitor the spare transformer inventory periodically to maintain the inventory at an adequate level. Therefore, there is no impact to the current investment plan for the TSP planning period (2020 to 2024).

1.4.2.6 ESL SURVEY OF TRANSFORMERS AND CIRCUIT BREAKERS

Utilities face a growing challenge to reduce operating and maintenance costs without adversely affecting service levels or investment requirements. EPRI designed two surveys to acquire information and insights on industry attitudes and practices related to asset management of transmission circuit breakers and transformers. This survey pools a number of electrical utilities (27 respondents for breakers and 35 respondents for transformers from across North America) to assess whether Hydro One’s current ESLs for transformers and circuit breakers are aligned with industry best practices. Hydro One uses ESL as a screening factor to assess investment need and pacing. The ESL is used as a trigger for a more in depth investigation through detailed asset condition assessment.

Transformers

EPRI’s transformer survey found that the ESL used within Hydro One for transformers is closely aligned with industry consensus. Moving forward, Hydro One will continue to stay current with industry best practices with respect to setting ESL for transformers.

The survey also found that Hydro One’s transformer replacement and assessment practice is similar to the majority of respondents, including target replacements based upon assessment of the asset using test and inspection results. The majority of utilities have a formal process and algorithm for assessing transformer condition with,75% of these utilities use a risk-based approach with condition and system criticality ranking highest for their algorithm inputs. Like Hydro One, most utilities do not allow the algorithm to trigger a replacement but also rely on the input of subject matter expert assessments.

Circuit Breakers

With respect to circuit breakers, EPRI found that Hydro One's ESL for the various types of circuit breakers in the transmission system are aligned with industry best practices as indicated by the survey results. Hydro One will therefore continue to pace the rate of replacements in accordance with its current practice. Hydro One will monitor this pace and adjust as required if information or trending dictates otherwise.

The circuit breaker survey also indicated that Hydro One was one of the few utilities to have a formal circuit breaker condition algorithm and/or process for assessing circuit breaker condition. Like Hydro One, most of the utilities that have such a process do not allow automatic replacement based only on the algorithm but also rely on subject matter expert assessments. The majority of respondent utilities replace circuit breakers by type/family regardless of individual age or condition with decisions highly based on population condition, ownership costs, reliability, safety, and environmental impact.

1.4.2.7 ESL ASSESSMENT OF SPECIFIC RELAYS

Hydro One's protective relay fleet consists of three technologies: electromechanical, solid state, and microprocessor. Electromechanical relays have the longest ESL and have very reliable performance. At the time of the report, solid state relays account for 58% of all relays currently operating beyond ESL, which is a risk to safety and reliability as shown in TSP Section 2.2.1.3. Microprocessor based relays (IEDs) now represent 52% of the total installed base. Specific microprocessor relays have performed poorly, leading Hydro One to question the validity of the 20-year ESL. As a result, Hydro One hired Kinectrics to quantify the risk associated with solid state and microprocessor relays and to advise on the appropriate pacing for replacement.

The Kinectrics report identified that Hydro One's ESL range is above the industry range of 13 to 19 years for solid-state relays and in-line with the range of 13 to 20 years for microprocessor relays. The study identified the possibility of increasing ESL for the examined solid-state and microprocessor relay models, but did not offer further guidance as to the appropriate level.

Relay replacements are selected based on various criteria and not solely dependent on ESL, as described in TSP Section 2.2. Hydro One will review its current practices and decision making process as well as continue to track and monitor the performance of its relays, based on the report's recommendations, to maximize the utilization of the relay fleet while managing its associated risk.

1.4.2.8 ESL ASSESSMENT OF SPECIFIC UNDERGROUND TRANSMISSION CABLES

Hydro One makes asset replacement decisions based on detailed condition assessments that verify whether an asset has reached its end of life. In this context, ESL is used as a screening factor and acts as a population health assessment metric. Based on the original design criteria, Hydro One is using 50 years as the ESL for its underground cables. However, operating experience within Hydro One and other utilities is suggesting an ESL of more than 50 years for low-pressure and high-pressure liquid-filled cables may be more appropriate. This study was carried out to determine the suitable ESL based on technical and engineering principles, condition assessment and operating experience.

EPRI has determined due to the current loading on Hydro One's low-pressure and high-pressure liquid-filled (LPLF and HPLF) cables that the suitable ESL should be increased to 70 years. Hydro One has previously been using 50 years as the ESL for these assets. The ESL is not used to trigger replacement. Replacement is triggered by asset condition. As the cable replacements planned for the 2020 to 2024 planning period of this rate application are based on the end of life condition of these cables, no changes will be made to the current investment plan. Hydro One has incorporated EPRI's recommendation and study findings into its cable asset strategy.

1.4.2.9 REVIEW OF UTILITIES' MANAGEMENT OF AIR BLAST CIRCUIT BREAKERS

This is a survey of industry best practices on the effective management of Air Blast Circuit Breakers ("ABCBs"). The industry in general is phasing out ABCBs due to poor performance, high maintenance costs and technological obsolescence. This survey has reviewed industry experience and assessed attitudes, experience and practices related to ABCBs to assist Hydro One in understanding how peer companies are responding to similar challenges and inform its own strategies for addressing this class of assets.

The data EPRI collected for this survey has demonstrated that Hydro One's approach to managing ABCBs is consistent with the industry norm. Some survey respondents mentioned they no longer had air blast breakers. EPRI's review found that "The higher cost/difficulty associated with maintenance requirements when compared to newer technology, the unavailability of spare parts due to obsolescence, and the lack of dedicated crews to work on the ever-aging population of installed air blast circuit breakers may lead to longer outage times associated with both routine and emergency maintenance. This could become problematic for utilities and customers on both a cost and service-reliability perspective."

This study confirms that other utilities are also replacing or have already replaced their ABCBs due to poor performance and associated high costs for maintenance. The lack of available spare parts to properly maintain these types of breakers has become problematic for utilities due to the age of the technology and obsolescence. These results confirm that Hydro One is aligned with industry best practices to remove the ABCB fleet from service.

1.4.2.10 REVIEW OF UTILITIES' MANAGEMENT OF OIL CIRCUIT BREAKERS

This is a survey of industry best practices on the effective management of Oil Circuit Breakers ("OCBs"). This survey was conducted to review industry experience, assess practices related to OCBs and to understand how peer companies are responding to similar challenges. High voltage OCBs are an older technology that relies on complex mechanical systems for operation and large amounts of oil for insulation. OCB technology has generally performed well over decades of service. However, due to their age, insufficient ratings and environmental concerns about oil, OCBs may be considered less desirable technology. For these reasons, many utilities have decided to reduce the size of their OCB fleets.

The results of this study confirm that other utilities are also replacing their OCBs due to poor performance and associated high costs for any maintenance. The lack of available spare parts to properly maintain these types of breakers has become problematic for utilities due to the age of the technology and obsolescence. These results confirm that Hydro One is aligned with industry best practices to remove the OCB fleet from service. Hydro One intends to remove these breakers at the pace indicated in the business plan for the test years.

1.4.2.11 DEGRADATION RATES OF STEEL TOWER COATING SYSTEMS

The study results will be used to improve the accuracy and resolution of the Ontario Atmospheric Corrosion Map by performing detailed assessments on 100 steel structures. The findings will be used to identify and optimize Hydro One's steel structure maintenance requirements and enhance its service life extension approach.

This study confirms that the majority of Southern Ontario falls under the C4 corrosion rate category, with small pockets of C5[1] corrosion rate zones. The resolution of the atmospheric corrosion map has been refined with more defined boundaries between the various corrosion zones. This information enables Hydro One to use the higher resolution of the Ontario Atmospheric Corrosion Rate Map to optimize the tower coating program and to maximize the steel tower lifecycle. Hydro One accepts EPRI's recommendation to use the updated Ontario Atmospheric Corrosion Map to make more accurate decisions about the degradation of steel structures throughout the province. Hydro One plans to address these recommendations by overlaying the updated atmospheric corrosion map with existing HONI Geographic Information System ("GIS") data, in order to more accurately assign corrosion zones to each structure.

1.4.2.12 POLYMER INSULATOR POPULATION ASSESSMENT

Hydro One has a large population of 230 kV and 115 kV polymer insulators. Some of these insulators are showing signs of deterioration, which has led to several failures in the past years. Two of these failures have resulted in line drops. Hydro One removed 87 in-service polymer insulators from various configurations within the Hydro One transmission service territory to enable sampling and testing. EPRI performed a detailed assessment of these assets and provided insights into the overall population condition to inform Hydro One's replacement needs.

Based on its assessment of 87 insulators, EPRI found that the condition of polymer insulators currently in-service in Hydro One's transmission system varies based on voltage, manufacturer and use of corona rings. The results of this study have shown that Hydro One should plan to remove specific 230 kV insulators from service as soon as

[1] Based on the ISO 9223, typical atmospheric environments are categorized from C1 through to C5, with C1 exhibiting very low in corrosivity, and C5 exhibiting very high corrosivity.

possible due to immediate or high risk of failure. Other types of 230 kV insulators should continue to be assessed periodically for signs and degree of degradation. EPRI further recommends that linemen should check the integrity of these insulators prior to performing any live maintenance procedures due to potential safety issues. Considering the study results, Hydro One will prioritize the removal of specific polymer insulators in its current replacement program.

1.4.2.13 PHASE 2: CP/COB PORCELAIN INSULATOR POPULATION ASSESSMENT

This is Phase 2 of the 1965 to 1982 vintage Canadian Ohio Brass (COB) and Canadian Porcelain (CP) insulator population condition assessment study. Phase 1 was completed in 2016 and was intended to ascertain the urgency for taking action to ensure safety at publicly accessible locations. Phase 2 required the removal of approximately 600 insulators from service and subjected these samples to more detailed laboratory testing (compared to Phase 1) to further assess their long-term condition and assist Hydro One in prioritizing and pacing future replacements of these assets.

After testing 591 samples, EPRI found overwhelming evidence to support the recommendation that Hydro One should remove the fleet of COB and CP porcelain insulators from service as soon as is practically possible to mitigate the risk to safety and reliability. Based on the results of Phase 2 COB/CP testing, insulators posing a higher public safety risk (i.e. insulators in critical locations) will be replaced by 2022 at a rate of approximately 3,700 circuit structures per year.

1.4.2.14 REVIEW OF HYDRO ONE'S CAPABILITIES IN TRANSMISSION ASSET ANALYTICS AND RELIABILITY RISK MODELLING

Hydro One engaged Metsco to perform a third-party assessment of three elements of its transmission system Asset Management ("AM") process, namely the Asset Analytics ("AA"), Asset Risk Assessment ("ARA") and Reliability Risk Model ("RRM") frameworks. The study reviewed Hydro One's AA and decision-making process, the six criteria, methodology, and data inputs utilized to calculate asset scores, and identified areas for improvement and other recommendations.

Metsco's overall conclusion was that across the categories of assessment, and in consideration of their utilization relative to other analytical and diagnostic tools comprising Hydro One's AM process, both ARA and AA are comparable to other asset management frameworks found elsewhere in the industry, and are sufficiently rigorous and robust to accomplish their intended tasks from the analytical perspective.

With respect to the RRM, Metsco found that the tool's analytical underpinnings and functionalities trail advanced industry system reliability practices where these are deployed. In making this observation, it was noted that a number of transmission utilities do not or have not until recently attempted to formally forecast system reliability in a comprehensive manner. This contextual observation suggests that the RRM capability constitutes a bona fide continuous improvement step – one that poses no meaningful system planning risks given the limited role that it currently plays in the AM process.

This study identifies that although Hydro One has a robust and rigorous process, there is always an opportunity to improve. The recommendations from this review will inform Hydro One's efforts to enhance its processes used to manage its major transmission assets, transformers, breakers and conductors. As part of its commitment to continuous improvement, Hydro One has implemented enhancements to its Asset Analytics investment planning decision support tool in 2018. The enhancements updated the existing algorithms and weighting calculations to improve the quality of the asset risk model to better inform decision making.

1.4.2.15 INVESTMENT PLANNING PROCESS REVIEW

Hydro One engaged BCG to prepare this report in response to the OEB's request for Hydro One to review its investment planning process. To conduct the review, BCG identified a set of capabilities typically required to execute an investment planning process competently. These were drawn from two sources – ISO 55000 asset management standards and industry best practices gathered through interviews with experts and through BCG's experience working with leading utilities globally. Recommendations from BCG for improvements to Hydro One's Asset investment planning process will inform future efforts by Hydro One to improve its planning process.

This study confirms that overall, Hydro One has implemented a consistent, thorough planning process that meets or exceeds expectations for a typical utility planning process in all areas. This information supports Hydro One's submission that the Investment Planning Process is robust and previous issues identified have been addressed. The report also includes recommendations that encourage Hydro One to continue to collect relevant condition data, update strategies, and implement forecasting outcome measures. Hydro One's progress regarding the implementation of these recommendations is provided in Attachment 15 to this Exhibit.

1.4.3 (5.3.2 C, 2.4.3) TECHNICAL FINDINGS FROM BENCHMARKING AND OTHER STUDIES

This section provides additional technical details regarding the key technical findings of each study, survey or assessment to support the high-level discussion in Section 1.4.2.

1.4.3.1 RESULTS OF PTX ANALYSIS OF HYDRO ONE'S TRANSFORMER FLEET

Table 1 - Key Study Findings of PTX Analysis of Hydro One's Transformer Fleet

#	Key Study Findings	Study Reference
1	EPRI's PTX methodology has identified 129 transformers with elevated Normal Degradation Index (NDI) within Hydro One's fleet of transformers	Section 3 (Page 3-1)
2	EPRI's PTX methodology has identified 88 transformers with elevated Abnormal Index that could consist of abnormal thermal, electrical and/or core problems within Hydro One's fleet of transformers	Section 3 (Page 3-1)
3	A single transformer can have multiple indices at elevated levels within a single PTX analysis	Section 3 (Page 3-2)

Table 2 - Recommendations of PTX Analysis of Hydro One's Transformer Fleet

#	Recommendations	Study Reference
1	A transformer with a high abnormal index rating should be assessed / re-assessed in the short term.	Section 2 (Page 2-2)
2	A transformer with a high normal degradation index rating should be assessed for long term needs	Section 2 (Page 2-2)

1.4.3.2 DERIVATION OF TRANSMISSION SUBSTATION TRANSFORMER HAZARD FUNCTIONS

Table 3 - Derivation of Transmission Substation Transformer Hazard Functions Key Study Findings

#	Key Study Findings	Study Reference
1	An updated methodology has been provided by EPRI to use a "prior distribution" to forecast probable number of replacements over a five year time period.	Section 3 (Pages 3-8, 3-17, 3-26, 3-35)
2	Hazard curve function analysis suggests that the removal rate of Hydro One's fleet can be categorized in 2 regions, where Region 1 can closely approximate Hydro One failure rate.	Section 2 (Page 2-6)
3	Hazard curve function analysis suggests that the removal rate in Region 2 is largely due to discretionary removal (planned replacement)	Section 2 (Page 2-6)

1.4.3.3 DERIVATION OF CIRCUIT BREAKER HAZARD FUNCTIONS

Table 4- Derivation of Circuit Breaker Hazard Functions Key Study Findings

#	Key Study Findings	Study Reference
1	Methodology is provided for using a "prior distribution" to forecast probable number of replacements over a five year time period.	Section 3 (Pages 3-9, 3-18, 3-27, 3-36, 3-45, 3-54, 3-63, 3-72, 3-81, 3-90, 3-99, 3-108, 3-117, 3-126)
2	Hazard curve function analysis suggests that the removal rate of Hydro One's fleet can be categorized in 2 regions, where Region 1 can closely approximate Hydro One failure rate.	Section 2 (Page 2-3)
3	Hazard curve function analysis suggests that the removal rate in Region 2 is largely due to discretionary removal (planned replacement)	Section 2 (Page 2-3)

1.4.3.4 DERIVATION OF OVERHEAD CONDUCTOR HAZARD FUNCTION

Table 5 - Derivation of Overhead Conductor Hazard Function Key Study Findings

#	Key Study Findings	Study Reference
1	By applying EPRI's Weibull Hazard model, the ACSR conductor fleet median age for reaching EOL based on existing condition assessment data is about 90 years ("91 years").	Section 4 (Pages 4-3 to 4-4)
2	By applying EPRI's Weibull Hazard model, the ACSR conductor fleet median age for reaching EOL, based on historical conductor replacements is about 90 years ("89.5 years").	Section 4 (Pages 4-3 to 4-5)
3	Based on Key Study Finding #1 above, an additional 2,264 km of conductor is expected to be beyond expected service life by 2024.	Section 5 (Page 5-3)

1.4.3.5 OPERATING SPARE TRANSFORMERS REQUIREMENT ASSESSMENT

Table 6 – Operating Spare Transformer Requirement Assessment Key Findings

#	Key Study Findings	Study Reference
1	EPRI's independent analysis to determine the appropriate number of Operating Spare Transformers aligns with Hydro One's inventory.	Table 4-1 (Page 71)

1.4.3.6 ESL SURVEY OF TRANSFORMERS AND CIRCUIT BREAKERS

Table 7 – Transformer Key Survey Findings

#	Key Findings	Report Reference
1	Around three-quarters of respondents used some formal definition of End of Life	Section 8 (Page 8-1)
2	Majority of participants expressed concerns when power transformer operates beyond 50 years.	Section 8 (Page 8-2)
3	Majority of participants target replacements based upon assessment of the asset using test and inspection data.	Section 8 (Page 8-3)
4	Just over 50% of utilities budget for a specified number of replacements per year with the highest weights on condition of individual asset and budgetary constraints	Section 8 (Page 8-3)
5	Half of utilities refurbish transformers to extend life	Section 8 (Page 8-3)

#	Key Findings	Report Reference
6	Majority of utilities do have a formal process or algorithm for assessing transformer condition. Nearly 75% of utilities use a risk-based approach with condition and system criticality ranking highest for their algorithm inputs	Section 8 (Page 8-3)
7	Most utilities that have a formal process or algorithm for assessing transformer condition do not allow the algorithm to automatically trigger a replacement	Section 8 (Page 8-3)

Table 8 – Circuit Breaker Key Survey Findings

#	Key Findings	Report Reference
1	Majority of respondents get concerned about breaker based on age beginning at approximately 44 years of age.	Section 8 (Pages 8-1 to 8-2)
2	Two-thirds of respondents do not run transmission circuit breakers to failure	Section 8 (Page 8-2)
3	Condition and safety are the two highest ranked criteria by respondents for replacing a breaker	Section 8 (Page 8-2)
4	Majority of utilities do not have a formal process or algorithm for assessing circuit breaker condition	Section 8 (Page 8-2)
5	Most utilities that have a formal process or algorithm for assessing circuit breaker condition do not allow the algorithm to automatically trigger a replacement	Section 8 (Page 8-2)
6	Majority of utilities do replace circuit breakers by type/family regardless of individual age or condition with decisions highly based on population condition, population ownership costs, population reliability, safety, and environmental impact.	Section 8 (Page 8-2)

1.4.3.7 ESL ASSESSMENT OF SPECIFIC RELAYS

Table 9 - ESL Assessment of Specific Relays Key Study Findings

#	Key Study Findings	Study Reference
1	MCGG 22 relays: six out of the nine component categories, or 67%, exceeded 25 years by the end of the test. For the remaining three component categories many more months of heat-soaking would be required to age these to 25 years.	Page 25
2	D60 relays: nine out of the 12 component categories, or 75%, exceeded 20 years by the end of the test. For the remaining three component categories, many more months of heat-soaking would be required to age these to 25 years.	Page 27

Table 10 - ESL Assessment of Specific Relays Recommendations

#	Recommendations	Study Reference
1	Review the deemed ESL values of 25 and 20 years respectively for the MCGG 22 and D60 relays.	Page 32
2	Continue heat-soak testing of both MCGG 22 and D60 relays for demonstrating the set reliability target pertaining to resistors, relays (miniature) and inductors/transformers/chokes.	Page 33

1.4.3.8 ESL ASSESSMENT OF SPECIFIC UNDERGROUND TRANSMISSION CABLES

Table 11 – ESL Assessment of Specific Underground Cables Key Study Findings

#	Key Study Findings	Study Reference
1	Both LPLF and HPLF cables have been operated below their thermal limits resulting in minimal thermal insulation degradation.	Section 3 (Page 12 & 15)

Table 12 – ESL Assessment of Specific Underground Transmission Cables Recommendations

#	Recommendations	Study Reference
1	The ESL of both LPLF and HPLF cables can be increased to 70 years.	Section 6 (Page 26)
2	Hydro One should continue its maintenance and testing program.	Section 6 (Page 26)
3	Cable condition will be evaluated in detail five years prior to it reaching its ESL to determine if additional maintenance or replacement is required.	Section 6 (Page 26)

1.4.3.9 REVIEW OF UTILITIES' MANAGEMENT OF AIR BLAST CIRCUIT BREAKERS

Table 13 - Review of Utilities' Management of Air Blast Circuit Breakers Key Findings

#	Key Study Findings	Study Reference
1	Air blast circuit breakers are "more" to "much more costly/difficult" to perform both minor and major maintenance	Section 4 (Page 4-1)
2	ABCBs are "less" to "much less reliable" when compared to single pressure gas breakers.	Section 4 (Page 4-1)
3	Principal drivers behind programmatic replacement were operation and maintenance costs and an unacceptable level of reliability/availability.	Section 4 (Page 4-1)
4	The population of ABCBs for utilities has been reduced by two-thirds over the last decade with no new ABCBs being installed.	Section 4 (Page 4-1)
5	The lack of available spare parts to properly maintain these types of breakers has become problematic for utilities due to the age of the technology and obsolescence.	Section 4 (Page 4-1)

1.4.3.10 REVIEW OF UTILITIES' MANAGEMENT OF OIL CIRCUIT BREAKERS

Table 14 - Review of Utilities' Management of Oil Circuit Breakers Key Findings

#	Key Findings	Report Reference
1	Utility experience with OCBs is that these types of breakers are somewhat "more costly/difficult" on which to perform both minor and major maintenance.	Page 4-1

#	Key Findings	Report Reference
2	OCBs are somewhat "less reliable" when compared to single pressure gas breakers.	Page 4-1
3	Principal drivers behind programmatic replacement are unacceptable reliability/availability and insufficient ratings for below 138 kV and excessive costs, environmental, and other for above 138 kV.	Page 4-1
4	The population of OCBs for utilities has been reduced by approximately 18% over the last decade.	Page 4-1
5	Nearly 85% of OCBs that are currently installed are over 40 years of age.	Page 4-1
6	Utilities have diminished abilities to properly maintain oil circuit breakers. None of the utility respondents have dedicated crews to perform internal inspections/refurbishments or dedicated shops and/or dedicated contractors to maintain/overhaul oil circuit breakers.	Page 4-1
7	The higher cost/difficulty associated with maintenance requirements when compared to newer technology and the lack of dedicated crews to work on the ever-aging population of installed oil circuit breakers may lead to longer outage times associated with both routine and emergency maintenance.	Page 4-1

1.4.3.11 DEGRADATION RATES OF STEEL TOWER COATING SYSTEMS

Table 15 - Steel Tower Coating Systems Key Study Findings

#	Key Study Findings	Study Reference
1	The resolution of the corrosion rate map has been refined using 2017 field survey data and steel coupons.	Section 5 (Pages 25-27)
2	The majority of Southern Ontario falls under the C4 corrosion rate category, with small pockets of C5 corrosion rate zones.	Section 5 (Pages 25-27)

Table 16 - Steel Tower Coating Systems Recommendations

#	Recommendations	Study Reference
1	Use the Ontario Atmospheric Corrosion Map to make more accurate decisions about the degradation of steel structures throughout the province.	Section 5 (Pages 25-27)

#	Recommendations	Study Reference
2	Additional field surveys and deployment of additional steel coupons will increase the resolution of the maps and reduce the margin of error in structure selection.	Section 6 (Page 29)

1.4.3.12 POLYMER INSULATOR POPULATION ASSESSMENT

Table 17 - Polymer Insulator Population Assessment Key Study Findings

#	Key Study Findings	Study Reference
1	The 230 kV K-Line insulators with the 4-inch donut corona ring have an extremely high likelihood of electrical and or mechanical failure due inadequate control of the electric field on the surface of the rubber housing at the line end. The rubber housing at the line end of these insulators has been severely eroded leading to exposure of the fiberglass rod. Such exposure of the rod will result in either mechanical or electrical failure with a high probability of the insulator parting and causing a conductor drop.	Section 5 (Page 5-1)
2	The 230 kV NGK insulators installed without corona rings are showing signs of serious deterioration of the line-end rubber housing and deterioration of the secondary seal. As such, they are considered to have a high risk of failure.	Section 5 (Page 5-1)
3	The 230 kV NGK insulators installed with 8-inch corona rings are undergoing rubber housing damage at the line end due to the poor design of the mounting portion of the ring. Currently this deterioration does not appear overly serious, but it is not known how quickly the housing deterioration will progress. In the EPRI aging chamber and at one EPRI member utility site this deterioration did result in eventual failure.	Section 5 (Page 5-1)
4	The 230 kV Ohio Brass insulators installed without corona rings are showing rubber and seal deterioration at their line-end fittings. However, in EPRI's experience, the risk of failure can be significantly mitigated by retrofitting corona rings.	Section 5 (Page 5-1)
5	The 230 kV Sediver insulators (all equipped with 11-inch corona rings) are not showing any significant external deterioration	Section 5 (Page 5-1)
6	The 230 kV K-Line insulators installed with 8-inch corona rings do not show any significant signs of deterioration.	Section 5 (Page 5-1)
7	The 115 kV K-Line dead-end insulators do not show any significant visually observable ageing even though they have been in service for 27 years,	Section 5 (Page 5-1)
8	The silicone insulators which have not been damaged due to excessive fields on the rubber surface remain hydrophobic.	Section 5 (Page 5-1)
9	The non-silicone insulators show, as expected, a low degree of hydrophobicity.	Section 5 (Page 5-1)

#	Key Study Findings	Study Reference
10	Each of the insulator groups with the exception of the Ohio Brass insulators had a single insulator unable to meet the dye penetration test requirements.	Section 5 (Page 5-1)
11	Seven 230 kV K-Line insulators exhibited low resistance along their length after humidity conditioning. Of these seven, three had damage from power arcs and housing erosion which may explain their failure. The remaining four (all of which had 8-inch corona rings) will be further examined to determine the root cause of failure.	Section 5 (Page 5-2)
12	All but three insulators passed the test. Of the failing three units, two have been in service for 26 and 27 years, and the third had major line-end rubber erosion and rod exposure.	Section 5 (Page 5-2)

1 **Table 18 - Polymer Insulator Population Assessment Recommendations**

#	Recommendations	Study Reference
1	All 230 kV K-Line insulators fitted with 4-inch donut corona rings should be removed from service as soon as possible since they pose a proven risk of immediate failure.	Section 6 (Page 6-1)
2	All the 230 kV NGK insulators installed without corona rings should be removed from service as they are considered to be at high risk of failure.	Section 6 (Page 6-1)
3	All the 230 kV Ohio Brass insulators installed without corona rings should be removed from service.	Section 6 (Page 6-1)
4	The 230 kV NGK insulators fitted with 8-inch corona rings should be monitored for continuing degradation by removing samples periodically for inspection.	Section 6 (Page 6-1)
5	The seven 230 kV K-Line insulators which failed the water vapor ingress test should be subjected to additional testing followed by dissection to quantify the degree of concern which should be associated with their failing the water vapor ingress test. This type of issue is generally associated with poor bonding between the housing and the rod and is often a batch problem. Until the issue is understood, these insulators should not be maintained live without first checking their integrity with the EPRI developed insulator tester.	Section 6 (Page 6-1)

1.4.3.13 PHASE 2: CP/COB PORCELAIN INSULATOR POPULATION ASSESSMENT

Table 19 - Phase 2: CP/COB Porcelain Insulator Population Assessment Key Findings

#	Key Study Findings	Study Reference
1	A large number of the tested insulators at various ratings exhibited porcelain cracking after M&E testing. As an example, 23% of 59 insulator units with 50 kip rating failed M&E test.	Section 3 (Page3-10)
2	54% of 246 insulator units punctured (cracked) during thermo mechanical cycling (TMC) test based on table 3-8	Section 3 (Page 3-12)
3	The fact that the insulators are highly susceptible to electrical puncture under steep transient voltages due to lightning	Section 5 (Page 5-3)
4	The finding that TMC drastically decreases the already weak ability of the insulators to withstand electrical puncture	Section 3 (Page 5-3)
5	The fact that a significant number of insulators separated mechanically during the TMC.	Section 3 (Page 5-3)

Table 20 - Phase 2: CP/COB Porcelain Insulator Population Assessment Recommendations

#	Recommendations	Study Reference
	The analysis of testing performed on the 591 insulators removed from service in 2017 provides overwhelming evidence supporting replacement to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation of this work is that the identified population of COB and CP insulators be removed from service as soon as practically possible.	Section 6 (Page 6-1)

1.4.3.14 REVIEW OF HYDRO ONE'S CAPABILITIES IN TRANSMISSION ASSET ANALYTICS AND RELIABILITY RISK MODELLING

Table 21 - Review of Asset Analytics Methodology Recommendations

#	Recommendations	Study Reference
1	Consider clearly separating the risk factors/criteria in AA to (a) define probability of failure of a specific asset, and (b) incorporate the impact of asset failure to explicitly assess a broader variety of outage consequence costs, such as utility's and socioeconomic costs, including the costs associated with the environment, safety/collateral damages, environment, customer interruption costs and financial impacts. Given that many of these additional factors proposed for incorporation into AA are already considered in the subsequent ARA analysis, we qualify this recommendation by stating that HONI may wish to consider it at a juncture where a broader AM process reorganization may be contemplated.	Page 98
2	Re-visit the formulation of its present AA framework and consider potential regrouping / renaming of assessment factors components to better align it with commonly understood industry terminology (such as condition assessment/health index, or impact assessment/consequence cost), and take steps to develop more comprehensive explanatory manuals for its AA capabilities.	Page 98
3	Continue ongoing work to rectify data completeness gaps identified across the individual risk sub-categories for each asset class in Section 3.2, aiming for the highest practicable scores within the resource availabilities, and prioritizing the categories seen as most impactful in light of the criteria weightings.	Page 98
4	Consider supplementing the current condition parameters tracked for each major asset class with additional parameters tracked in the industry, as identified in the appropriate subsections of Section 3.2. As with all input enhancements, evaluate the incremental value proposition of additional parameters relative to the implementation costs by way of financial value for money analysis.	Page 98
5	Consider integration socio-economic factors, including costs to the customer (customer interruption costs), as well as environmental and safety-related monetary cost factors, such that the full range of economic costs (including those that go beyond those incurred by a utility or its customers) can be utilized as part of this evaluation procedure.	Page 98
6	Consider supplementing the obsolescence-based intervention assessments for Protection, Control, and Telecom assets by formally incorporating the results of manual SME activities that already occur in a less formalized manner.	Page 99

1 **Table 22 - Review of Reliability Risk Forecasting Methodology Recommendations**

#	Recommendations	Study Reference
1	Prior to investing any incremental resources into potential refinements, we encourage Hydro One's management to fully articulate a vision of the tool's ultimate place within its asset management and capital planning hierarchy, including whether such a tool is ultimately needed in light of all other capabilities. Subject to the outcome of deliberations suggested in the above recommendation, consider further enhancements to reliability forecasting through an RRM, or an alternative solution.	Page 99
2	Enhance reliability forecasting to assess reliability performance of the transmission system through a variety of reliability indices, rather than rely on the reliability risk modeling.	Page 99
3	Integrate the enhanced reliability forecasting solution into the overall asset management process to provide the asset managers with a more robust set of reliability outcome predictions based on a variety of investment scenarios under consideration.	Page 99
4	Include additional asset classes into the reliability forecasting approach (e.g. tower structures, insulators, switches) and sub-classes to improve the precision level of equipment related risk forecasting.	Page 99
5	Develop a capability to provide reliability risk prediction on a sub-system level, such as system regions or large customer groups.	Page 99
6	Expand the overall approach to reliability / reliability risk forecasting to factor in non-equipment related outages (e.g. weather events, adverse environment, human related errors, foreign interference, etc.) to forecast the reliability risks of the transmission system as a whole.	Page 99
7	Assess the reliability impact of the non-renewal projects in the enhanced reliability forecasting solution. If the utility does not have any such projects in the investment plan, than the benefits of this recommendation are not expected to outweigh the costs of developing this capability.	Page 99
8	Extend the reliability forecasting horizon to at least ten years to capture a greater extent of the long-lasting renewal and non-renewal projects within the investment scenarios on the system reliability.	Page 100
9	Enhance the algorithms utilized to calculate the age demographic profile for each asset class, by revisiting the priority of asset replacements and considering both reactive and inspection-determined failure modes of assets reaching their ends of lives.	Page 100
10	Revise asset class weights or the algorithms that calculate the reliability risk of three key asset classes per each investment scenario to incorporate more asset-specific failure considerations.	Page 100
11	Utilize a variety of econometric techniques to establish mathematical relationships between the non-asset and asset-related failure instances or modes, and factors that precipitate them.	Page 100

1.4.3.15 INVESTMENT PLANNING PROCESS REVIEW

Table 23 – Investment Planning Process Review Key Findings

#	Key Study Findings	Study Reference
1	Overall, Hydro One has implemented a consistent, thorough planning process that meets or exceeds expectations for a typical utility planning process in all areas.	Page 1

Table 24 – Investment Planning Process Review Recommendations

#	Recommendations	Study Reference
1	Improve condition data: Hydro One has made significant progress in ensuring its investment plans, and specifically its sustainment investments, are driven by an understanding of system and asset condition, but can continue to focus on developing potential investment projects using a rigorous, data-driven process. Hydro One aims to conduct condition testing on all end of life assets, and has processes in place to test critical stations and lines equipment. However, for some assets where a large share of the asset base is reaching end of life (e.g. conductors, insulators), Hydro One faces a backlog in condition testing. As a result, testing data is not available for all end of life assets, consistent with circumstances faced by many utilities with aging asset bases.	Page 3
2	Update asset strategies: Hydro One conducted a significant effort to update its asset strategies in parallel to its most recent planning cycle. Having updated asset strategies will strengthen Hydro One's asset management capabilities going forward. However, the parallel effort resulted in some asset strategies not yet being in place for the onset of 2017 planning process. Teams were able to leverage legacy asset strategies as they developed the 2017 plan, and the investments included in the plan align with the finalized asset strategies. As a result, the parallel nature of the asset strategy effort had limited impact on the quality of the plan.	Page 4
3	Increased outcome definition: In 2017, Hydro One was able to translate the results of its investment plan into expected customer outcomes with greater specificity than it had in previous years, leading to 5 year targets for key scorecard metrics. As Hydro One tracks actual performance against its forecasted outcomes, there is an opportunity to refine the accuracy of its forecasting methodology for future years, which will help Hydro One more accurately predict the outcomes provided by its investment portfolio. We would also recommend Hydro One leverage the same methodology to forecast 1 year outcomes for its scorecard metrics, in addition to the 5 year forecasts already in place.	Page 4

1.4.4 (2.4.3) ATTACHMENTS: BENCHMARKING STUDIES

Attachment	Study /Assessment Report
Attachment #1	Results of PTX Analysis of Hydro One’s Transformer Fleet
Attachment #2	Derivation of Transmission Substation Transformer Hazard Functions
Attachment #3	Derivation of Circuit Breaker Hazard Functions
Attachment #4	Derivation of Overhead Conductor Hazard Function
Attachment #5	Operating Spare Transformers Requirement Assessment
Attachment #6	Expected Service Life (“ESL”) Survey of Transformers and Circuit Breakers
Attachment #7	Expected Service Life (“ESL”) Assessment of Specific Underground Transmission Cables
Attachment #8	Review of Utilities’ Management of Air Blast Circuit Breakers
Attachment #9	Review of Utilities’ Management of Oil Circuit Breakers
Attachment #10	Degradation Rates of Steel Tower Coating Systems
Attachment #11	Polymer Insulator Population Assessment
Attachment #12	Phase 2: CP/COB Porcelain Insulator Population Assessment
Attachment #13	Review of Hydro One’s Capabilities in Transmission Asset Analytics and Reliability Risk Modeling
Attachment #14	Assessing Hydro One’s Investment Planning Process
Attachment #15	BCG Report – Implementation of Recommendations
Attachment #16	ESL Assessment of MCGG 22 & D60 Relays

Results of Power Transformer Expert System (PTX) Software Analysis of Hydro One's Transformer Fleet

Results of PTX Analysis of Hydro One’s Transformer Fleet

Supplemental Project Report

Technical Update, December 2017

EPRI Project Manager
B. Desai

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

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The following organization prepared this report:

Electric Power Research Institute
1300 West W. T. Harris Blvd.
Charlotte, NC

Principal Investigators
B. Desai
T. Raymond
M. Warren

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ABSTRACT

This report describes the application of EPRI's Power Transformer Expert System (PTX) software to analyze Hydro One Networks Inc.'s fleet of transmission substation transformers to enhance Hydro One Networks Inc.'s ability to manage its transformer fleet.

A critical step in asset management is assessing the condition of in-service equipment accurately and efficiently. In no case is this more important than for substation power transformers. EPRI developed PTX to assess the condition of transformers by analyzing data from utility historical records, test results and name plate information. PTX identifies high-risk units for more detailed testing or increased monitoring which helps utilities to prioritize maintenance and replacements. The report provides an overview of PTX methodology and presents results of the Hydro One Networks Inc. analysis for each of the 729 transmission substation transformers for which data was provided.

Keywords

Power transformers

Fleet management

Asset management

Power transformer expert system

PTX

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1
INTRODUCTION AND BACKGROUND

Introduction

This report describes Hydro One's application of EPRI's Power Transformer Expert System (PTX) software to analyze its transformer fleet to assess short and long-term risk, determine failure rates and projections, and compare Hydro One's performance with the industry.

Background

Managing fleets of aging assets is a critical challenge for utility companies striving to maintain reliability and control costs in a constrained business environment. Transformer fleet management is an especially important subject for many utilities operating populations of power transformers that have significant numbers of units at or beyond their typically assumed design lives. Because a high percentage of transformers are approaching or even exceeding age forty, existing methods and a reliance on past performance may not be adequate for the effective management of this generation of transformers. Consequently, developing and justifying a repair/refurbish/replace management strategy for such populations and the rational basis for it, is a critical need.

EPRI's PTX integrates decades of expert knowledge and transformer performance data in a rule-based framework to provide a basis for asset management—including optimizing maintenance, increasing reliability, and capital planning decisions.

PTX assesses the present condition of transformers and identifies high risk units to support replacement strategies, monitoring needs and spares requirements. PTX also provides the user with a list of potential degradation or failure modes that may be occurring and the "belief" that PTX has that these conditions are actually in progress.

PTX evaluates the main tank, bushings and dielectric fluid modules and a generic framework for load tap changers.

The approach that the PTX software takes is intended to meet the following three objectives:

- Uses available information
- Incorporates advanced analytical capabilities
- Provides decision support for multiple stakeholders

Report Organization

In addition to this Introduction, the report is organized in the following chapters:

Chapter 2: Power Transformer Expert System (PTX): An Overview

Chapter 3: Results of PTX Analysis at Hydro One

Chapter 4: Hydro One Exploratory Graphics

2

POWER TRANSFORMER EXPERT SYSTEM SOFTWARE (PTX): AN OVERVIEW

This chapter presents a summary overview of PTX software. For this analysis PTX v4.0 was used to analyze Hydro One's fleet. The software is updated every year, with version 4.0 available in December 2017.

PTX Inputs and Outputs

PTX determines the present condition of a transformer using utility historical records and test results, along with each unit's name plate information.

Specific inputs to the software include:

Main Tank
- Dissolved gas in oil
- Furans and oil quality
- Family, make, application, age

Load Tap Changer
- Dissolved gas in oil
- Operations count
- Maintenance history
- Family, make, application, age

Bushings
- Power factor
- Capacitance
- Family, make, application, age

Dielectric Fluid
- Oil quality

PTX Outputs

As output, PTX produces a set of condition indices, as follows:

Main Tank Indices

- Normal Degradation Index
- Abnormal Degradation Indices
    - Core
    - Thermal
    - Electric

PTX also produces a Load Tap Changer Index, a Bushings Index, and a Dielectric Fluid Index. Note that the present analysis did not include assessment of the Load Tap Changers (LTC), as the condition assessment methodology for LTCs in PTX is not yet sufficiently mature for inclusion in this analysis. In addition, assessment of the transformer bushings was not performed.

PTX Condition Index Definitions

"Normal degradation" identifies units that may be approaching end of service life through expected degradation of paper from operation over an extended time.

"Abnormal degradation" identifies units that may be experiencing unexpected problems due to manufacturing defects or operating issues.

These transformers show the existence of some conditions that would not be present or expected in normal operation. This could be excessive temperatures that don't fit the pattern of gas seen with normally operating, heavily loaded transformers, or it could be some indication of partial discharge, arcing or sparking. Units with heating gases and no indication of paper involvement may also show up in the "abnormal core" category. The important difference, however, is that this index is NOT a function of service age. While some vintage-specific type issues may be involved, age does not increase or decrease an abnormal index. These conditions can occur at any point during the service life of a transformer. This index is more like other DGA condition categorizations but with significantly more intelligence and discrimination in the derivation of the indices' values. A high abnormal index value indicates a need to take more immediate action e.g. additional tests or monitoring or inspection. This index is useful for both maintenance and fleet and asset management.

Based on analyses of several transformer fleets, the following thresholds for each index have been established:

- 0.25 for the Normal Degradation Index
- 0.50 for the Abnormal Indices

These thresholds provide a reasonable signal to noise ratio based on experience to date. Transformers with indices above these thresholds should be evaluated by experienced personnel to establish future action.

Time to Action

Normal degradation is a slow process. Units with elevated Normal Degradation Indices are not expected to experience a rapid deterioration in condition in the near term.

Abnormal conditions, as represented by the Abnormal Condition Indices, may or may not evolve to a failure rapidly. The time to failure, should a failure occur, is highly variable. Certain conditions may be more severe, and thus more likely to evolve to failure more rapidly. In general, high Abnormal Condition Indices should be investigated immediately.

Development History and Data Points

The development of PTX had its origins in EPRI's XVisor project in the 1990s. XVisor was an early transformer expert system developed with extensive engagement and input from industry subject matter experts. The PTX development effort began in 2007 with a concept that involved multiple stakeholders and the analysis of readily available data from large transformer fleets. PTX Version 4, released in 2017, has been tested with data from some 32,000 transformers from 22 utility fleets—a total of 400,000-plus test data points. This work is documented in the EPRI technical update report *Analytics Assessment and Comparisons.* EPRI, Palo Alto, CA: 2017. 3002010221.

Normal Degradation Index (NDI) versus Degree of Polymerization (DP) is a much smaller data set. Paper samples are taken from transformers that have been analyzed with PTX, but few opportunities are available to obtain those samples. On occasions when a utility tears down a transformer, samples are taken and sent for laboratory analysis to determine DP to plot against NDI. Figure 2-1 presents a comparison of test results from retired transformers for DP versus NDI.

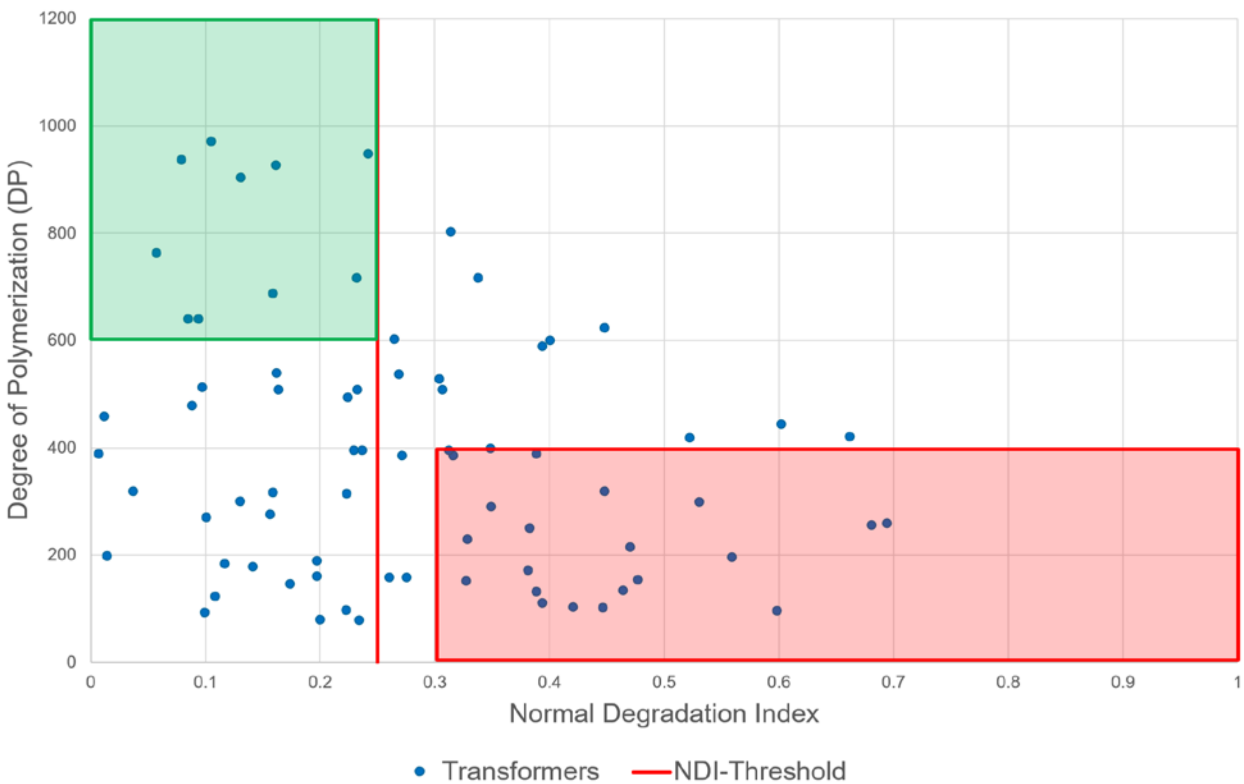


Figure 2-1
Comparison of Test Results from Retired Transformers (DP) and PTX Analysis

The test results show good correlation between NDI and actual paper condition, and the established threshold for concern (0.25) seems appropriate based on the samples obtained thus far. Although more samples are needed to improve confidence, the Normal Degradation Index is a useful indicator of paper condition.

Abnormal Index Validation

Case studies are useful, but do not provide a quantitative means for measuring effectiveness. With historical data on transformers that have failed, transformers removed from service before impending failure, and from healthy transformers, researchers can retroactively assess the performance of both PTX and other methods in blind back-testing.

For example, Figure 2-2 shows a performance evaluation approach for assessing the efficacy of different approaches at detecting faulty transformers using dissolved gas in oil analysis (DGOA). Table 2-1 shows the results of diagnostic methods evaluations.

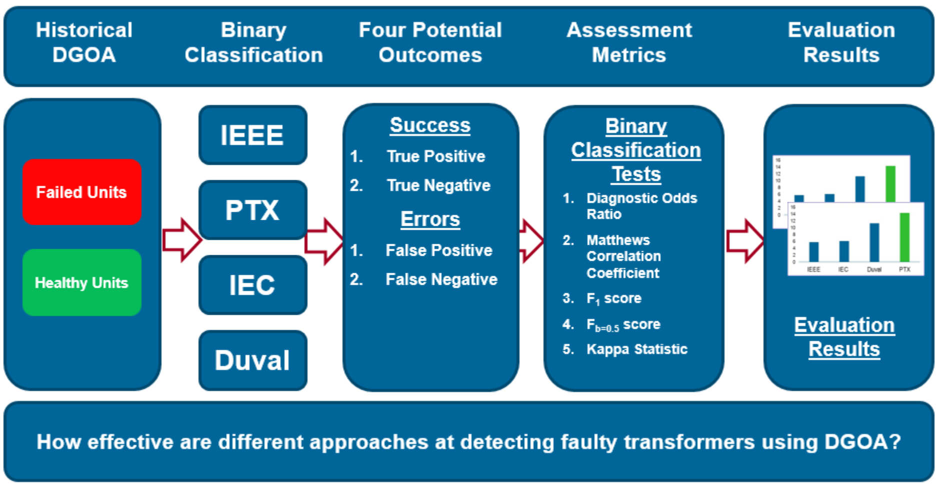


Figure 2-2
Performance Evaluation Approach

Table 2-1
Diagnostic Methods Evaluation

Performance Measure	PTX Rank Versus Other DGA Diagnostic Methodologies
Diagnostics Odds Ratio (with 95% Confidence Interval)	1st
Matthews Correlation Coefficient	1st
F_1 Score	1st
$F_{b=0.5}$ Score	1st
Kappa Statistic	1st

3
RESULTS OF PTX ANALYSIS AT HYDRO ONE

Introduction

EPRI worked with Hydro One to apply PTX version 4 to analyze the company's transformer fleet to:

- Identify transformers at risk
- Determine failure rates and projections
- View and compare performance with the industry

The analysis included 728 transformers and was limited to main tank DGA and Oil Quality samples from 1984 to 2017. The DGA and oil quality sample counts by year are shown in Figure 3-1.

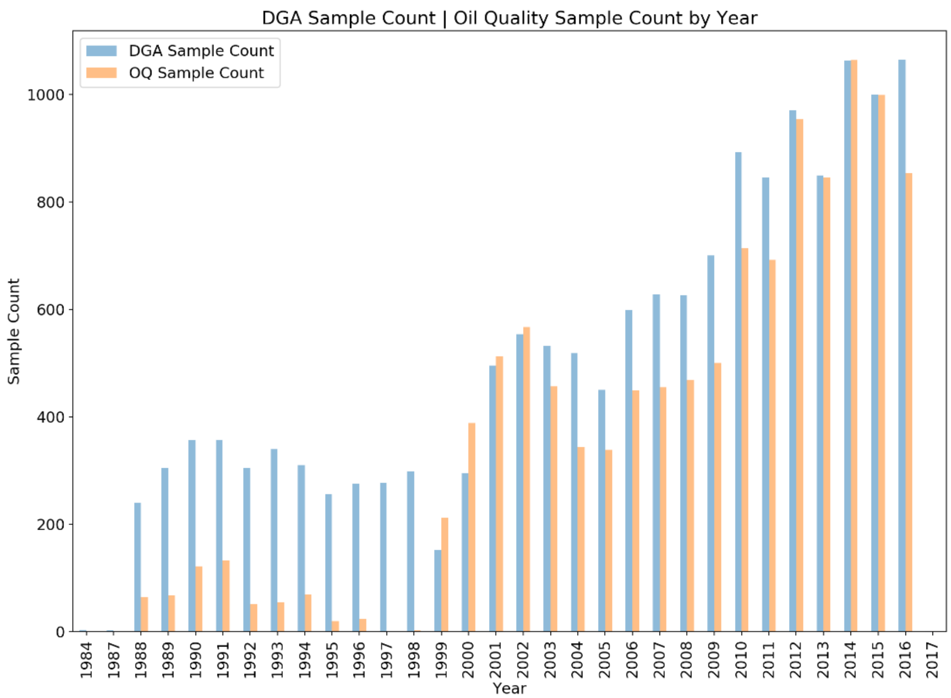


Figure 3-1
DGA and Oil Quality sample counts by year

- 129 transformers were flagged by PTX for elevated Normal Degradation Index (NDI)
- 88 transformers were flagged for elevated Abnormal Indices, as follows:
    - 10 Abnormal Thermal
    - 87 Abnormal Electrical

- 35 Abnormal Core

Transformers can have multiple elevated indices from one PTX analysis.

The tabulated results are presented in a spreadsheet in Appendix A.

Figure 3-2 shows the number of transformers by vintage.

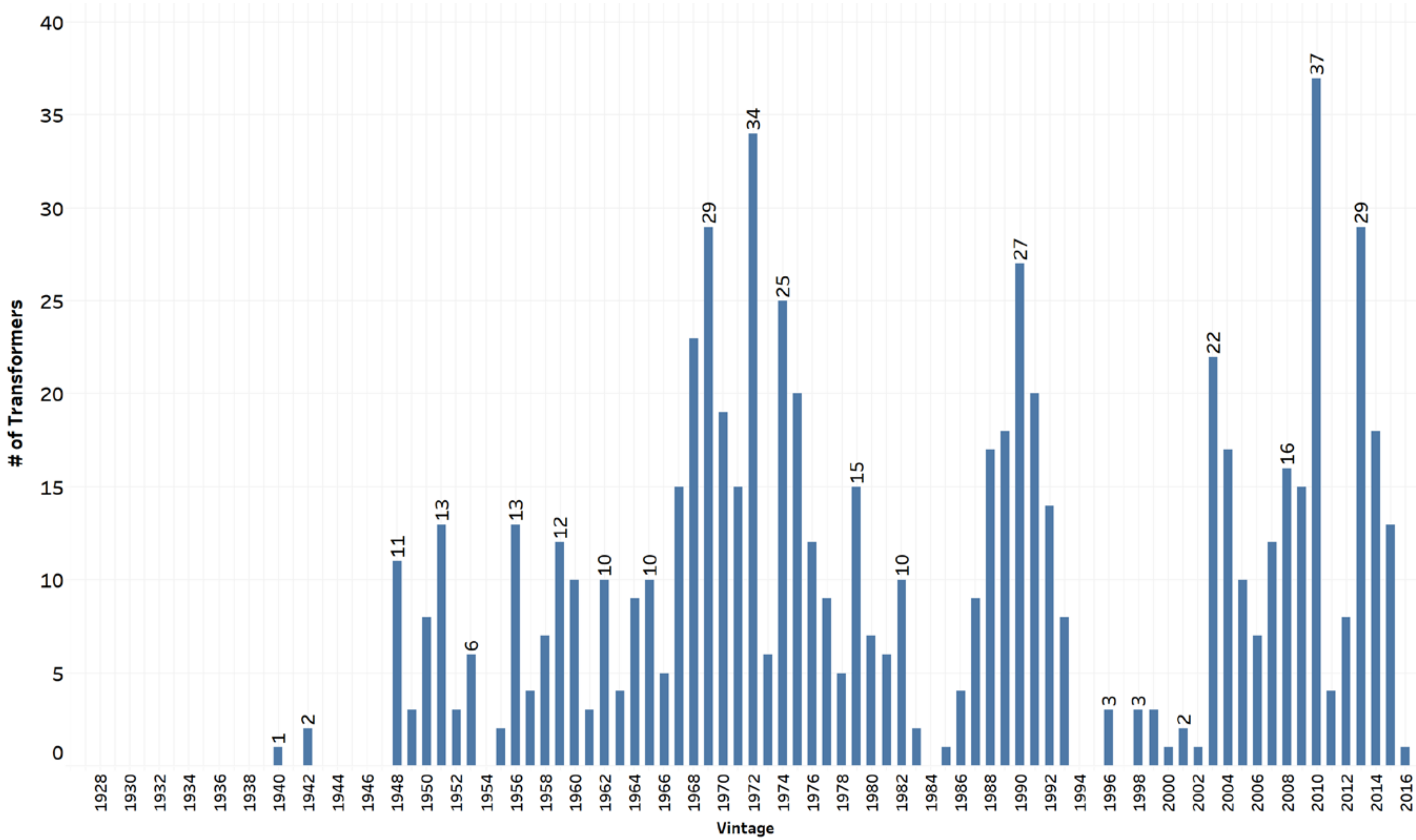


Figure 3-2
Number of Transformers by Vintage

Figure 3-3 shows transformers with elevated NDI by vintage.

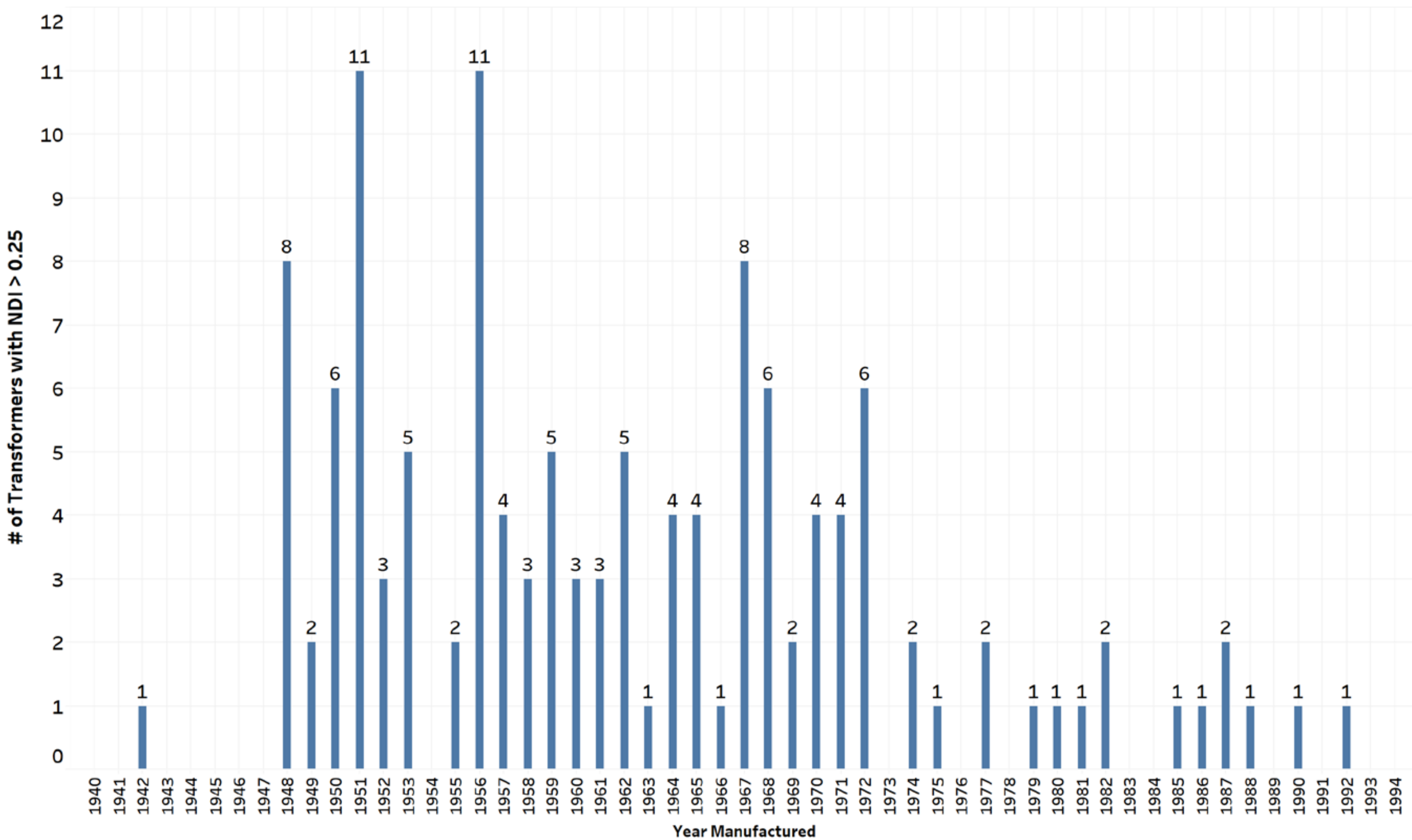


Figure 3-3
Transformers with Elevated NDI by Vintage

Figure 3-4 shows transformers with elevated abnormal indices by vintage. "Elevated abnormal indices" is defined by Abnormal Condition Code values greater than 3. Abnormal Condition Code is a metric that takes the maximum value of all abnormal indices for an individual transformer.

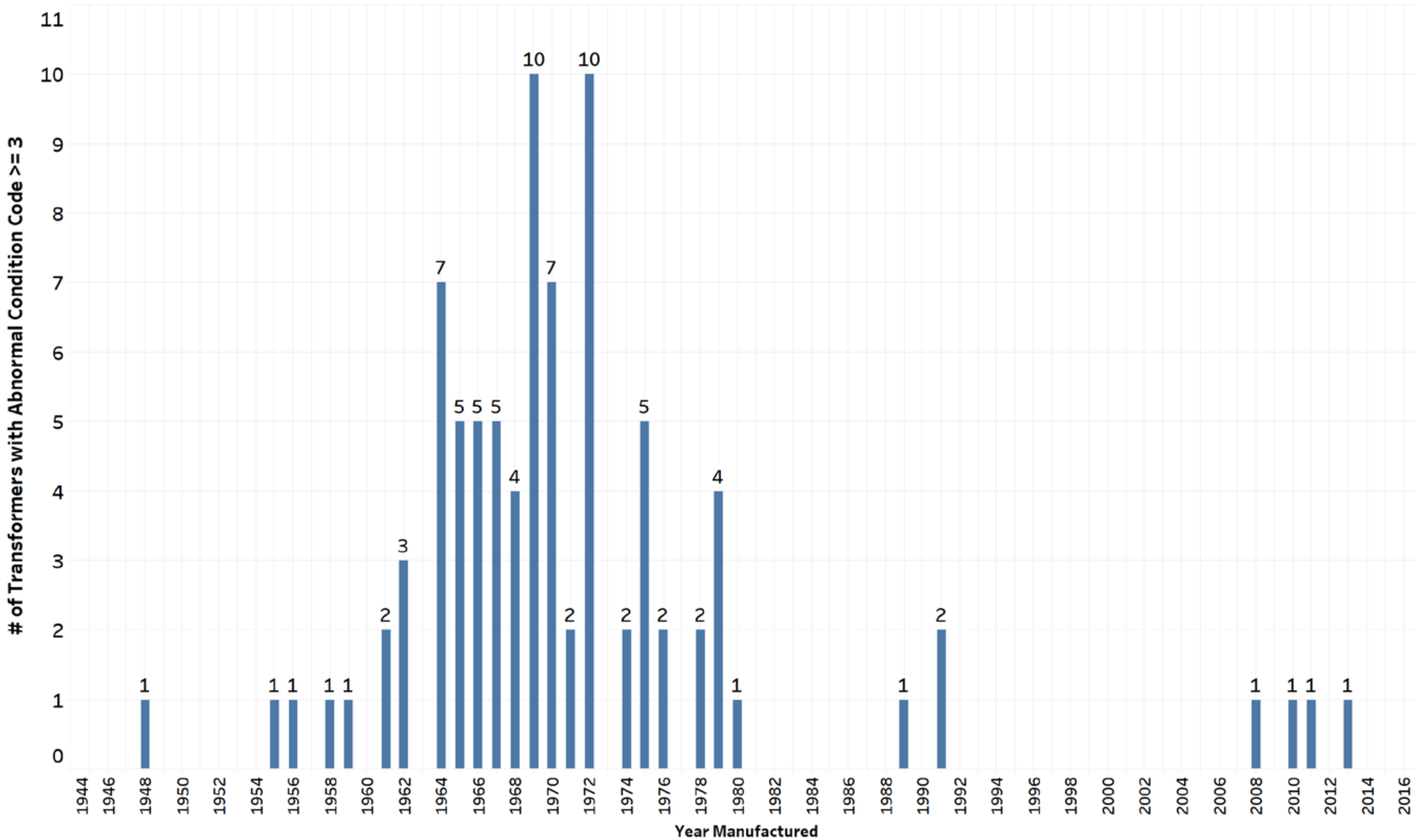


Figure 3-4
Transformers with Elevated Abnormal Indices by Vintage

Figure 3-5 is a histogram of NDI by voltage class. On the x-axis, NDI values are grouped with a bin size of 0.05. On the y-axis, the number of transformers is plotted for each voltage group per NDI bin. For example, SN:1191766, a 228.8 kV autotransformer manufactured in 1956, is in the 230 kV voltage group. Its NDI value of 0.63 puts it in the 0.60 bin which ranges from 0.60 to 0.65.

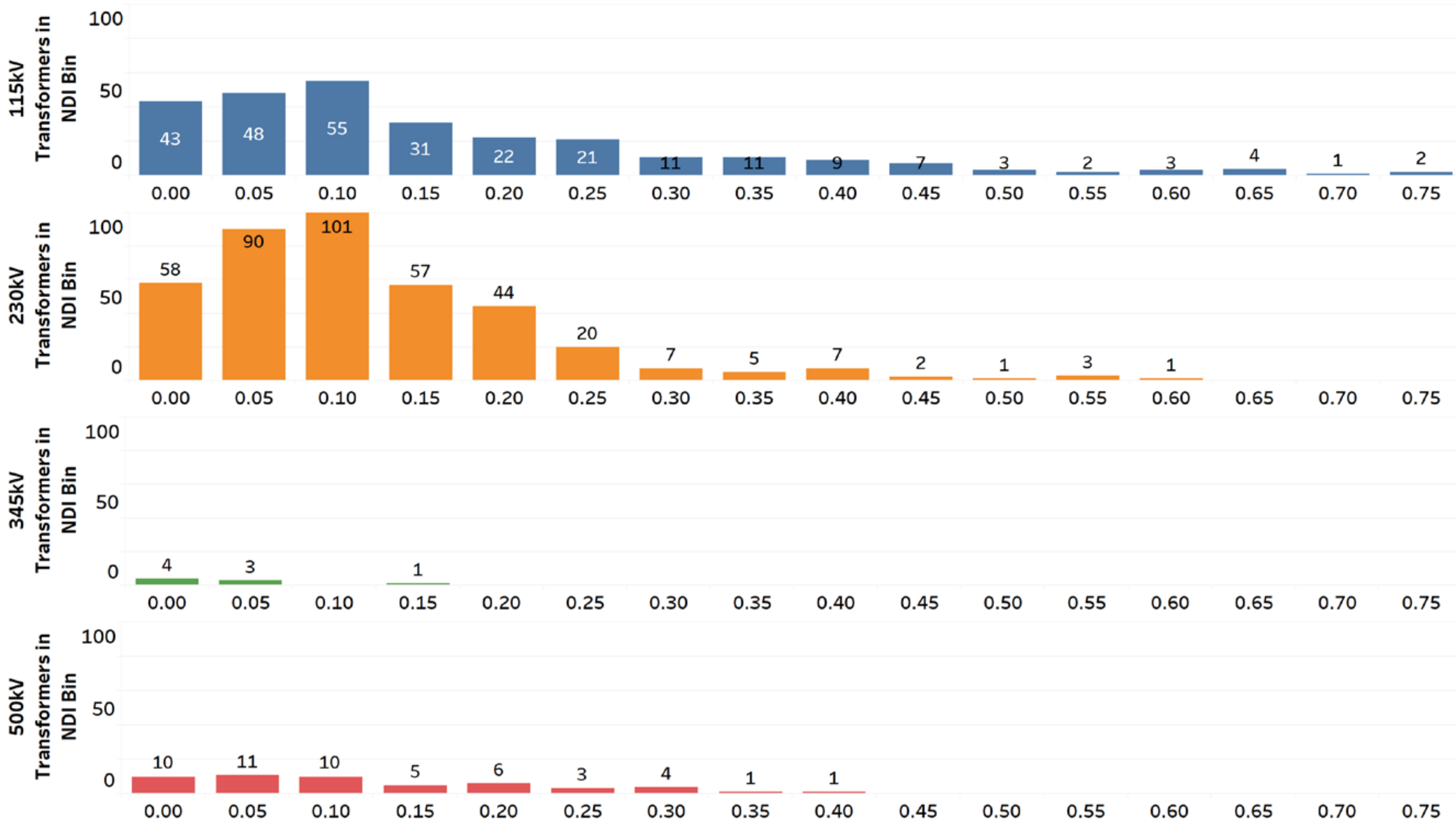


Figure 3-5
Histogram of NDI by Voltage Class

Figure 3-6 shows the number of transformers flagged by voltage class. For the Normal Degradation Index, a “flagged” means that a transformer’s NDI value is greater than 0.25. Flagged Abnormal Thermal transformers have an Abnormal Thermal value greater than or equal to 0.6. Flagged Abnormal Electrical transformers have an Abnormal Electrical value greater than or equal to 0.5. Flagged Abnormal Core transformers have an Abnormal Core value greater than or equal to 0.5.

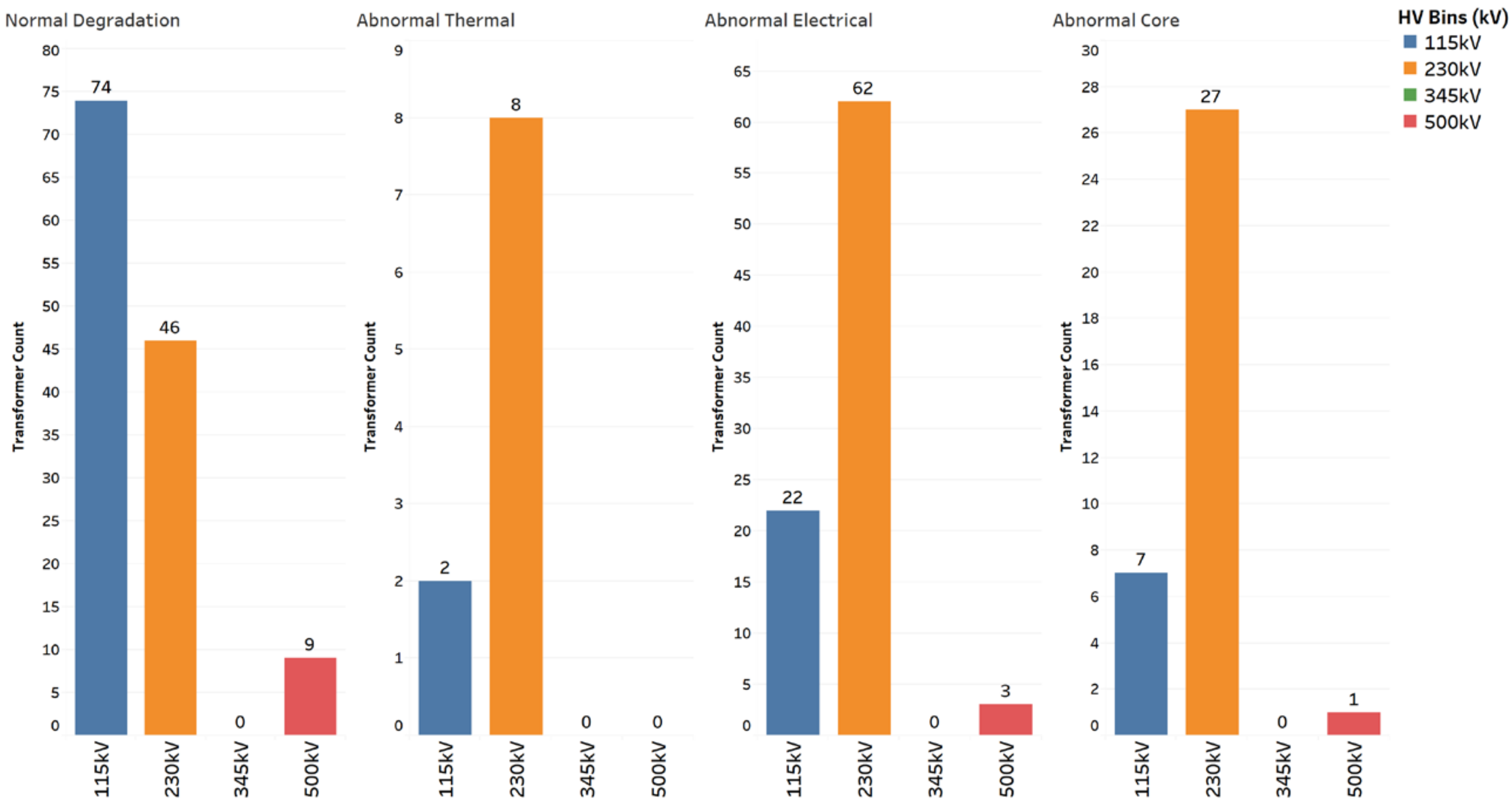


Figure 3-6
Number of Transformers Flagged by Voltage Class

Figure 3-7 shows transformers flagged abnormal by manufacturer. The top histogram shows total counts of transformers by manufacturer. The bottom histogram shows the number of transformers that have been flagged for any Abnormal Condition (Abnormal Thermal, Abnormal Electrical, and/or Abnormal Core).

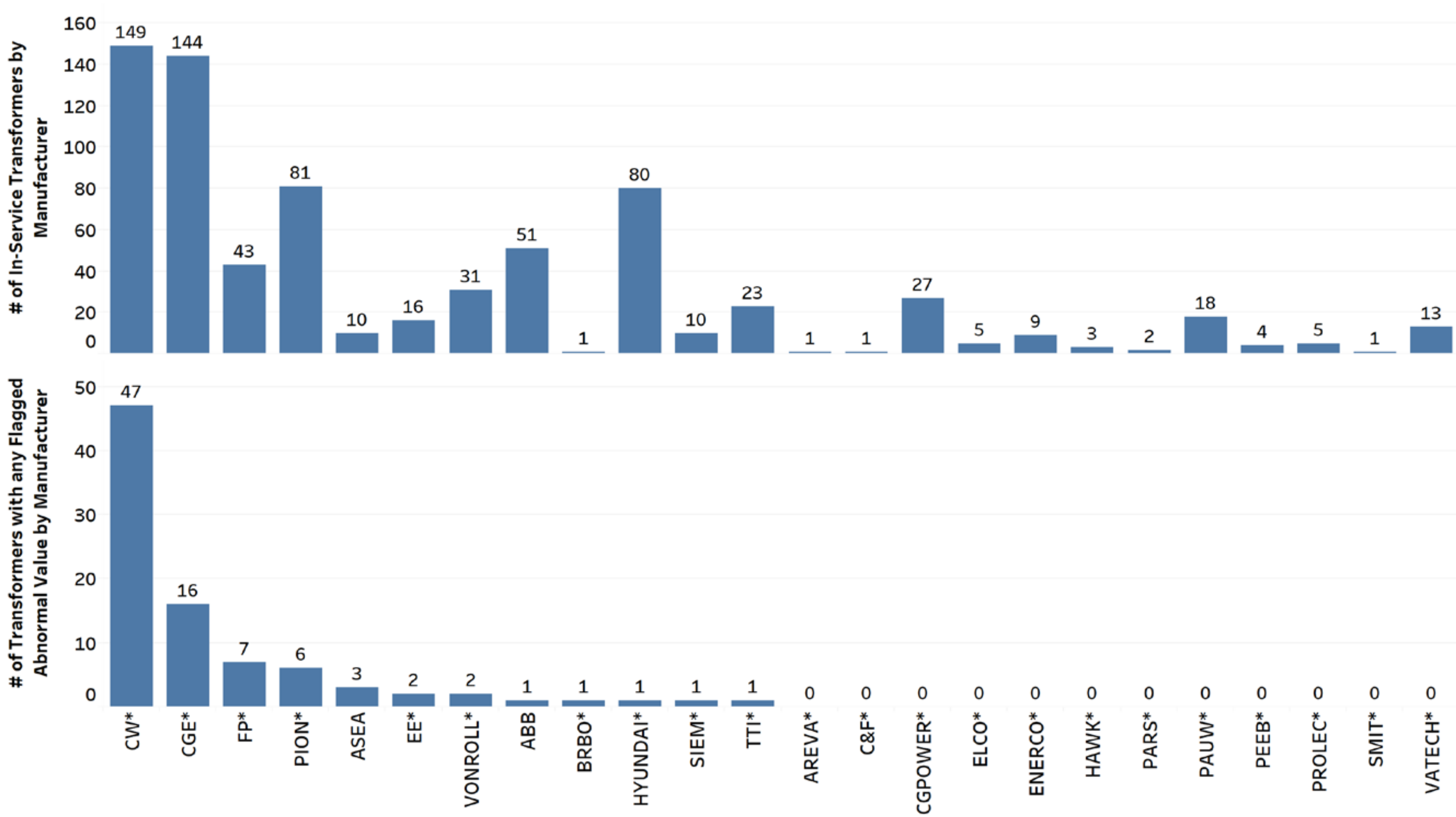


Figure 3-7
Transformer Flagged Abnormal by Manufacturer

Figure 3-8 presents histograms of abnormal indices for Canadian Westinghouse. The top histogram shows the total count of Canadian Westinghouse transformers by Abnormal Thermal 0.1 bins. The bottom histogram shows the total count of Canadian Westinghouse transformers by Abnormal Electrical 0.1 bins.

Figure 3-8
Histograms of Abnormal Indices for Canadian Westinghouse

500 kV Autotransformers above Threshold for Abnormal Indices

Table 3-1 shows transformers in the 500 kV voltage group with any flagged abnormal index value, as described before Figure 3-6. Figure 3-9, Figure 3-10, and Figure 3-11 show the DGA and PTX results for these units. Note that Hanmer T9 (B) and Porcupine T7 have been replaced.

Table 3-1
500 kV Group Transformers with any Flagged Abnormal Index Value

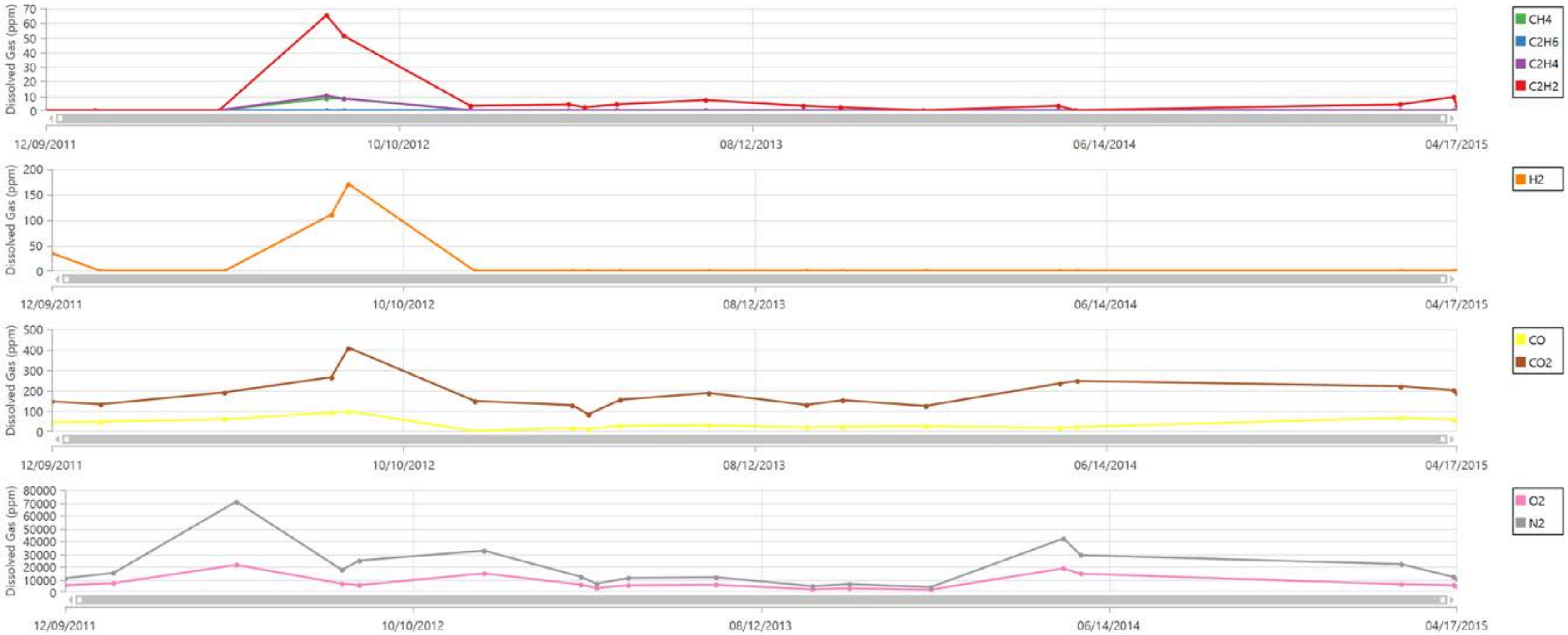
Station	N-TS-HANMERTS-TF-T9	N-TS-PORCUPINTS-TF-T7	N-TS-NANTICOKTS-TF-T13
Designation	(B) TF: Auto - 250MVA 500-240-28kV	TF: Auto - 360MVA 480-230-28kV	(W) TF: Stepdn - 116MVA 500-26.5KV
SAP Equipment Number	1176643	1189465	2383402
Vintage	1972	1967	2010
Manufacturer	CGE*	CW*	SIEMENS*
HV Voltage (kV)	500	480	500
HV Bins (kV)	500kV	500kV	500kV
Normal Degradation	0.35	0.04	0.03
H1 Short Term Risk	High Risk	High Risk	Fair
Abnormal Thermal Code	2	2	2
Abnormal Thermal	0.51	0.56	0.4
Abnormal Electrical Code	5	5	3
Abnormal Electrical	0.72	0.73	0.51
Abnormal Core Code	1	3	2
Abnormal Core	0.04	0.61	0.44

Normal Degradation	H1 Short Term Risk	Abnormal Thermal Code	Abnormal Thermal	Abnormal Electrical Code	Abnormal Electrical	Abnormal Core Code	Abnormal Core
0.35	High Risk	2	0.51	5	0.72	1	0.04

Figure 3-9
1176643 - N-TS-HANMERTS-TF-T9 (B)

Normal Degradation	H1 Short Term Risk	Abnormal Thermal Code	Abnormal Thermal	Abnormal Electrical Code	Abnormal Electrical	Abnormal Core Code	Abnormal Core
0.04	High Risk	2	0.56	5	0.73	3	0.61

Figure 3-10
1189465 - N-TS-PORCUPINTS-TF-T7



Normal Degradation	H1 Short Term Risk	Abnormal Thermal Code	Abnormal Thermal	Abnormal Electrical Code	Abnormal Electrical	Abnormal Core Code	Abnormal Core
0.03	Fair	2	0.4	3	0.51	2	0.44

Figure 3-11
2383402 - N-TS-NANTICOKTS-TF-T13

4
HYDRO ONE EXPLORATORY GRAPHICS

Introduction

This chapter provides graphical representation of the analysis results presented in Chapter 3 developed at Hydro One's request using their five-category ranking:

1. Very Good
2. Good
3. Fair
4. Risk
5. High Risk

Results of this effort are tabulated in a spreadsheet presented in Appendix A.

Table 4-1 shows the five-category ranking and corresponding metrics driven by the Normal Degradation Index (NDI). Table 4-2 shows the five-category ranking and corresponding metric driven by the Abnormal Indices (AI) as discussed in Chapter 2. The thresholds for the five-category ranking are based on subject matter expertise, informed by experience to date with application of PTX.

Note that this ranking, and the graphical representations presented in this chapter, show one possible way of grouping transformers. Other combinations are possible, including grouping by voltages, station names, geographical regions, and criticality.

Table 4-1
Category Thresholds for Normal Degradation Index

Ranking Category	Normal Degradation Index Thresholds
Very Good	0.0 to 0.1
Good	0.1 to 0.25
Fair	0.25 to 0.4
Risk	0.4 to 0.5
High Risk	>0.5

Table 4-2
Category Thresholds for Abnormal Indices

Index	Category 1 – Very Good	Category 2 - Good	Category 3 - Fair	Category 4 - Risk	Category 5 – High Risk
Electrical	0.0 to 0.3	0.3 to 0.5	0.5 to 0.6	0.6 to 0.7	> 0.7
Thermal	0.0 to 0.3	0.3 to 0.6	0.6 to 0.8	0.8 to 0.9	> 0.9
Core	0.0 to 0.3	0.3 to 0.5	0.5 to 0.7	0.7 to 0.9	> 0.9

Figure 4-1 is a primary voltage histogram of Hydro One transformers.

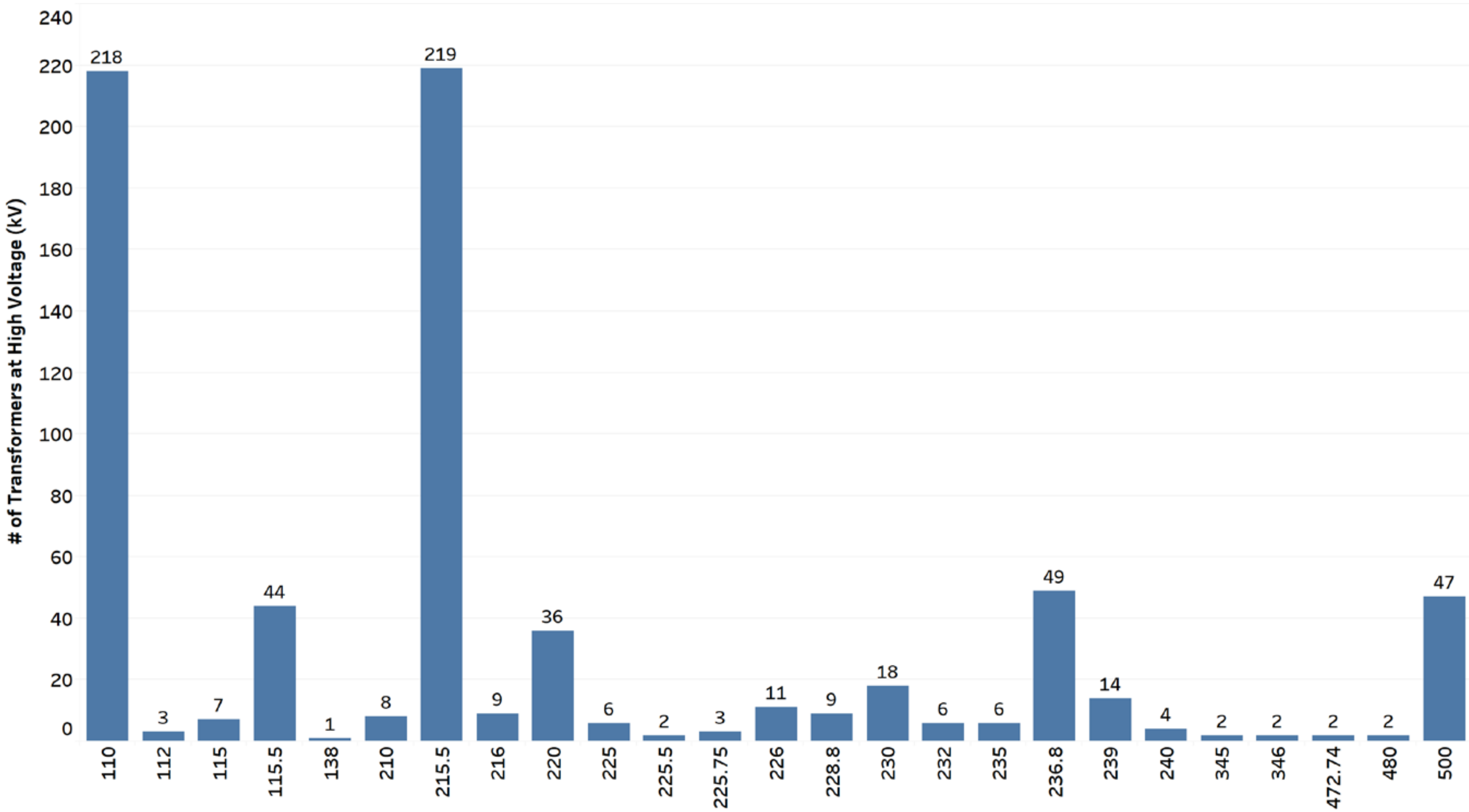


Figure 4-1
Primary Voltage Histogram

Figure 4-2 is an MVA histogram of Hydro One transformers.

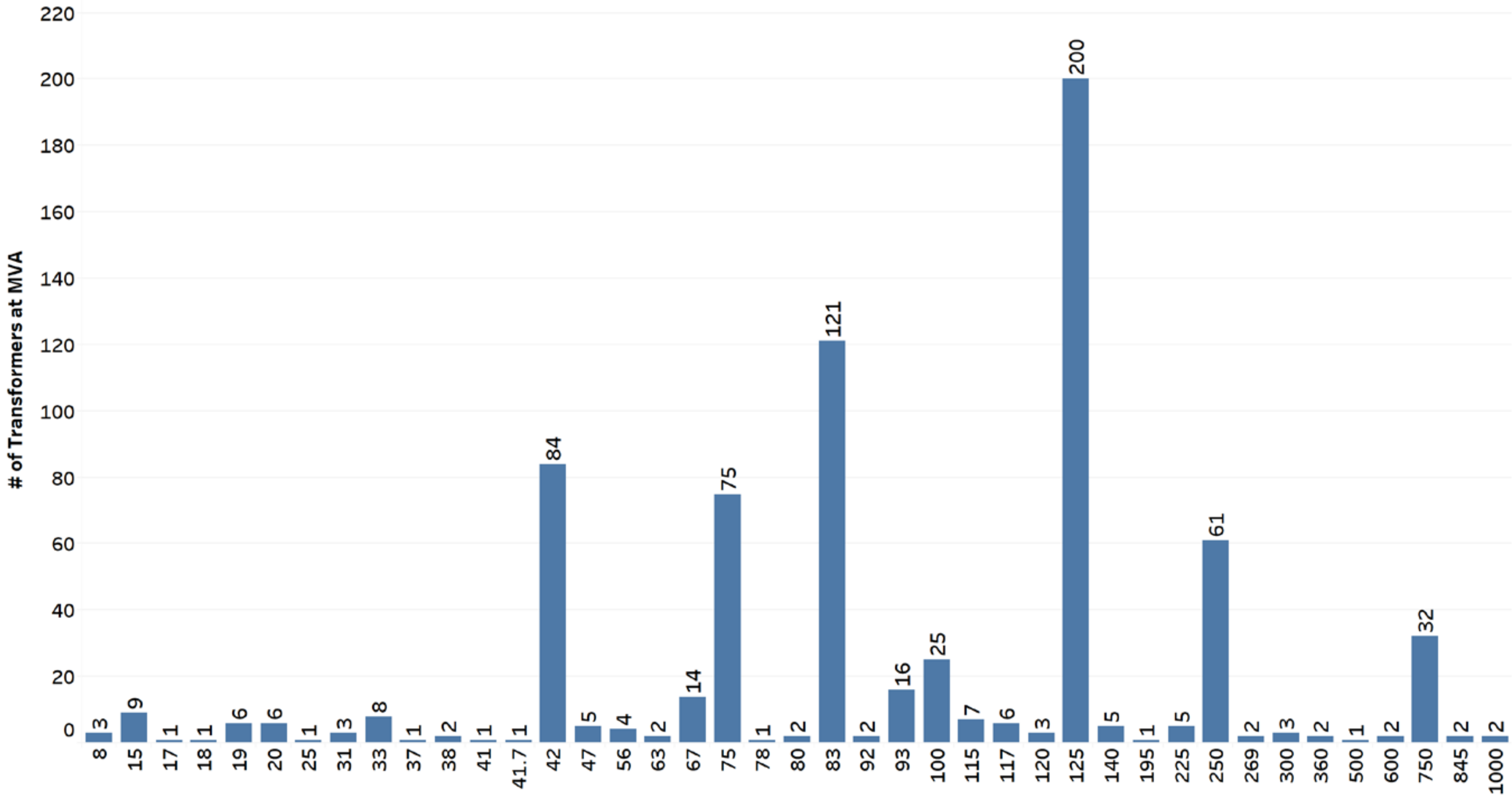
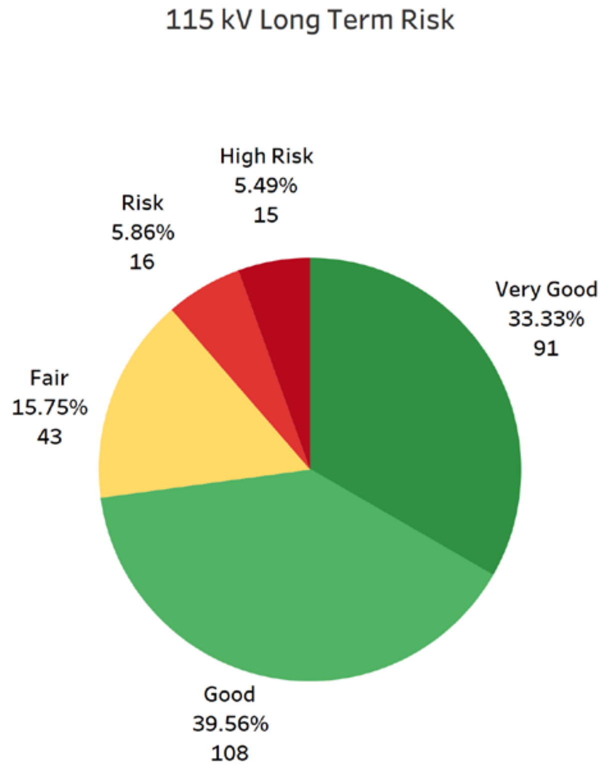


Figure 4-2
MVA Histogram

Figure 4-3 shows long-term and short-term risk for Hydro One's 115 kV units using the five-category ranking.



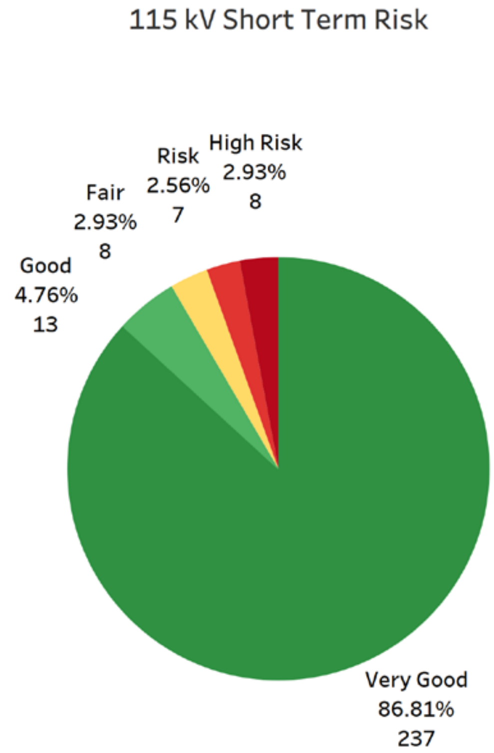


Figure 4-3
Long-Term and Short-Term Risk for 115 kV Transformers

Figure 4-4 shows 115 kV long-term risk transformers in the “Risk” and “High Risk” categories by MVA.

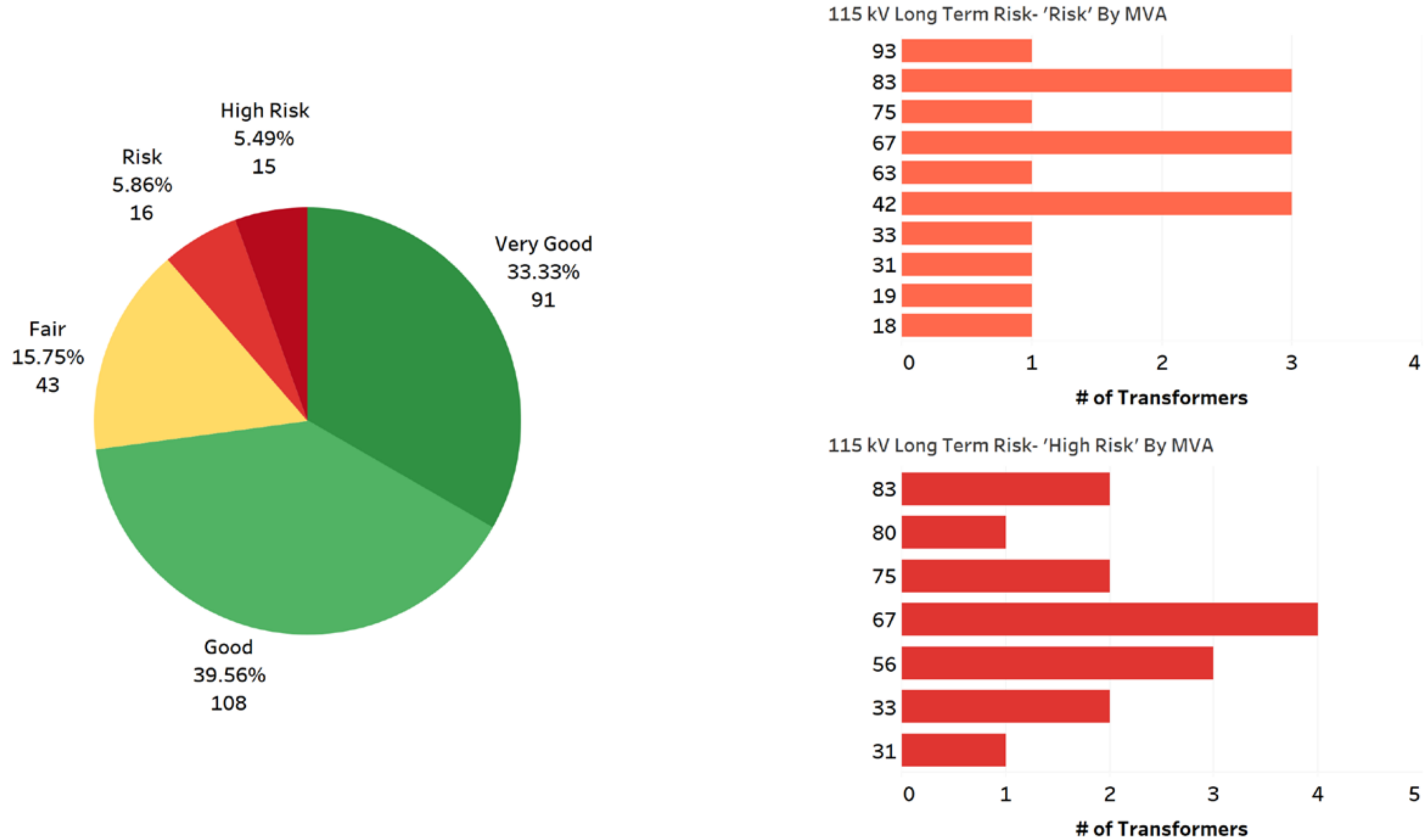


Figure 4-4
Long-Term “Risk” and “High Risk” 115 kV Units by Top MVA

Note that differences in count between pie chart counts and ‘Risk’ and ‘High Risk’ MVA bar charts are due to units where MVA value was not available being omitted from the bar charts.

Figure 4-5 shows 115 kV short-term risk transformers in the “Risk” and “High Risk” categories by Top MVA.

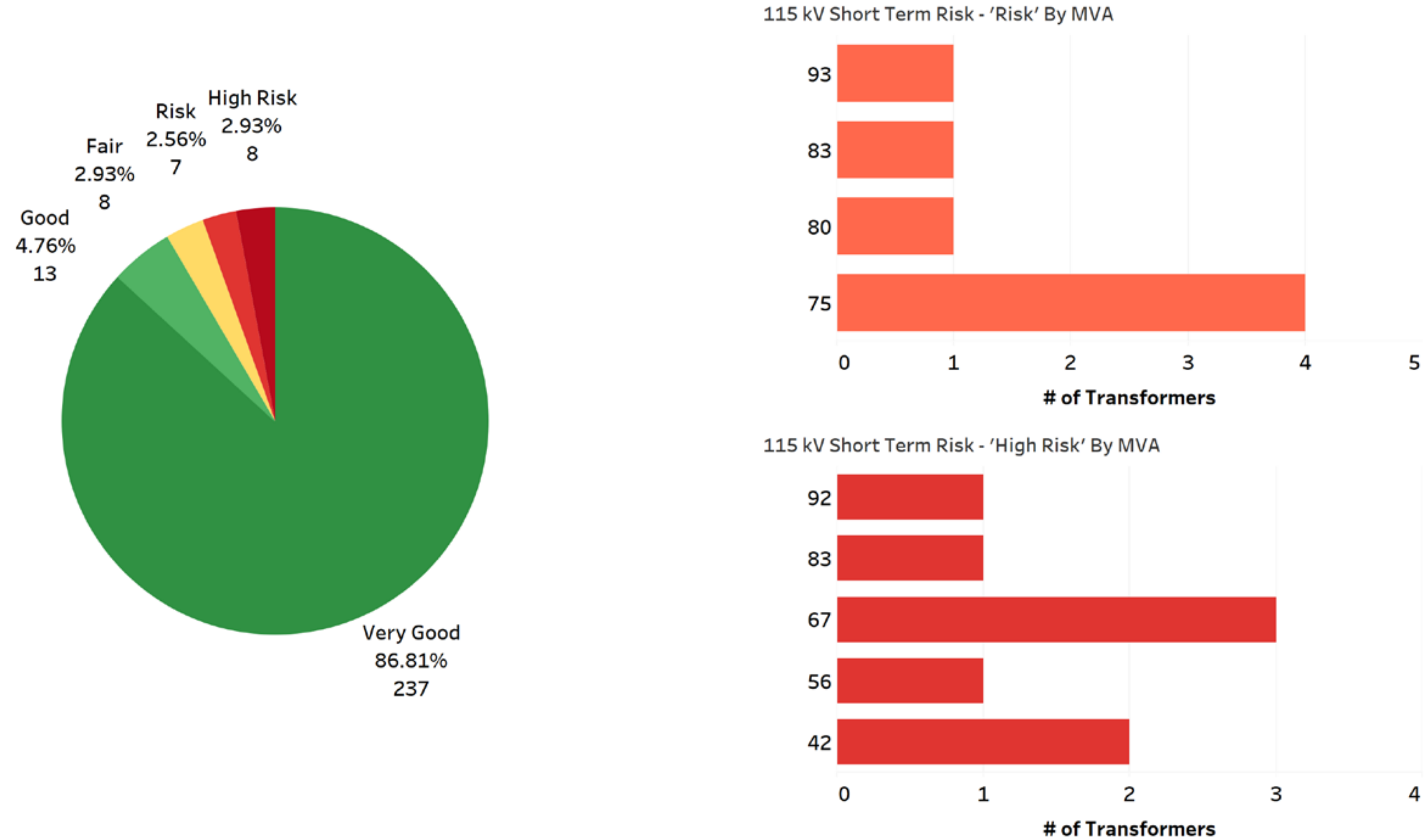
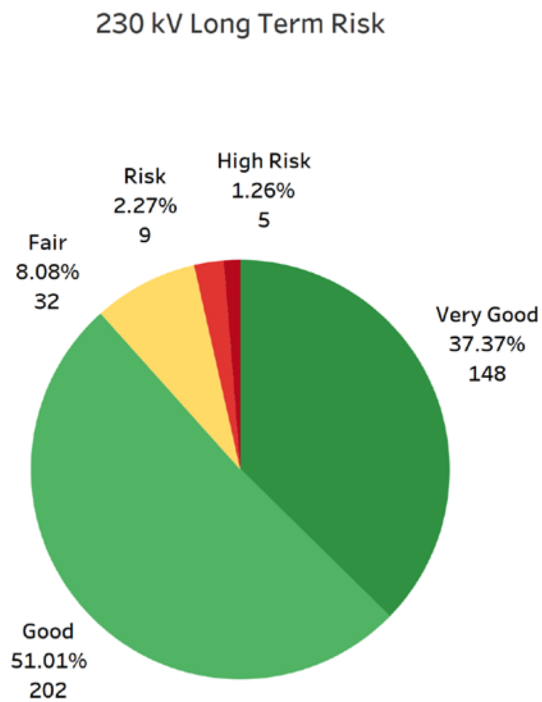


Figure 4-5
115 kV Short-Term Risk – “Risk” and “High Risk” Transformers – by Top MVA

Note that differences in count between pie chart counts and ‘Risk’ and ‘High Risk’ MVA bar charts are due to units where MVA value was not available being omitted from the bar charts.

Figure 4-6 shows long-term and short-term risk for Hydro One's 230 kV units using the five-category ranking.



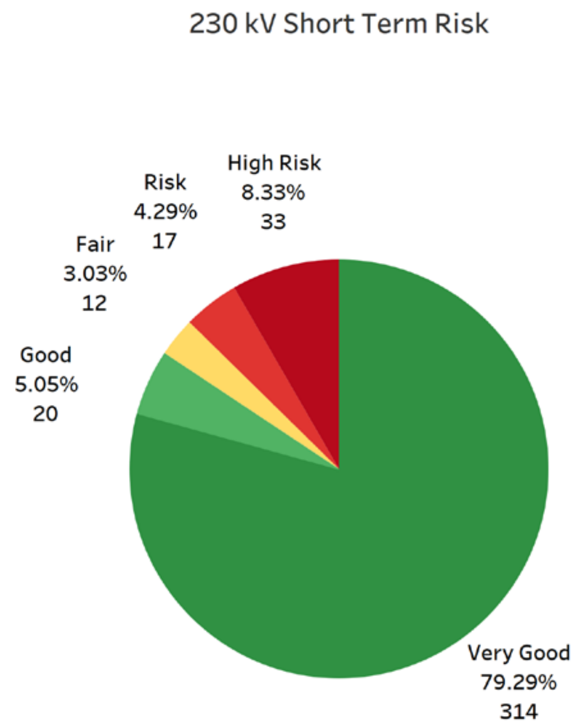
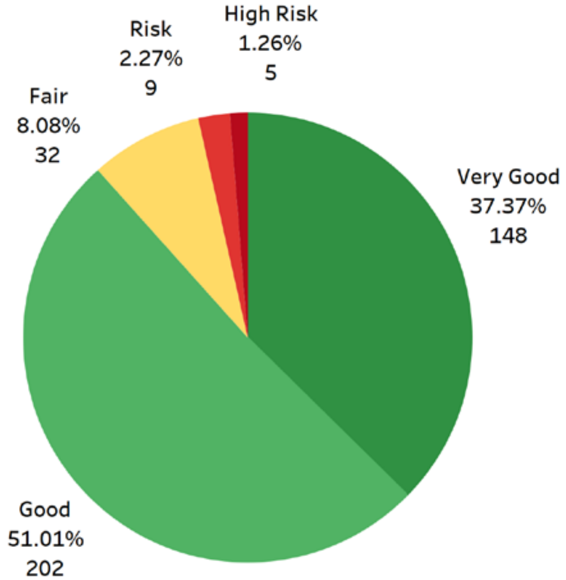


Figure 4-6
Long-Term and Short-Term Risk for 230 kV Transformers

Figure 4-7 shows 230 kV long-term risk “Risk” and “High Risk” categories transformers by MVA.



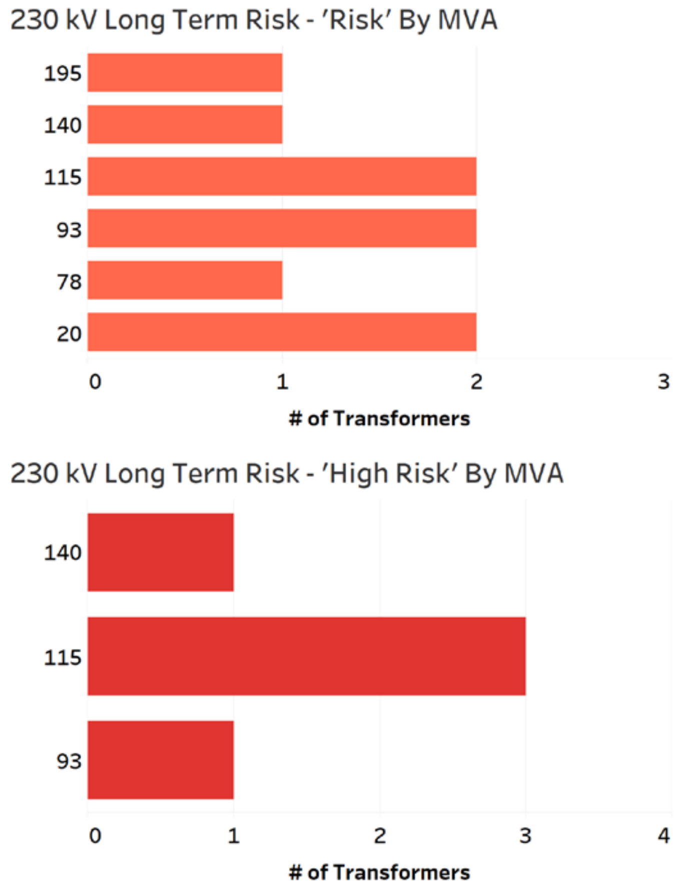


Figure 4-7
230 kV – Long-Term Risk – “Risk” and “High Risk” Transformers by MVA

Note that differences in count between pie chart counts and ‘Risk’ and ‘High Risk’ MVA bar charts are due to units where MVA value was not available being omitted from the bar charts.

Figure 4-8 shows 230 kV short-term risk transformers in the “Risk” and “High Risk” categories by MVA.

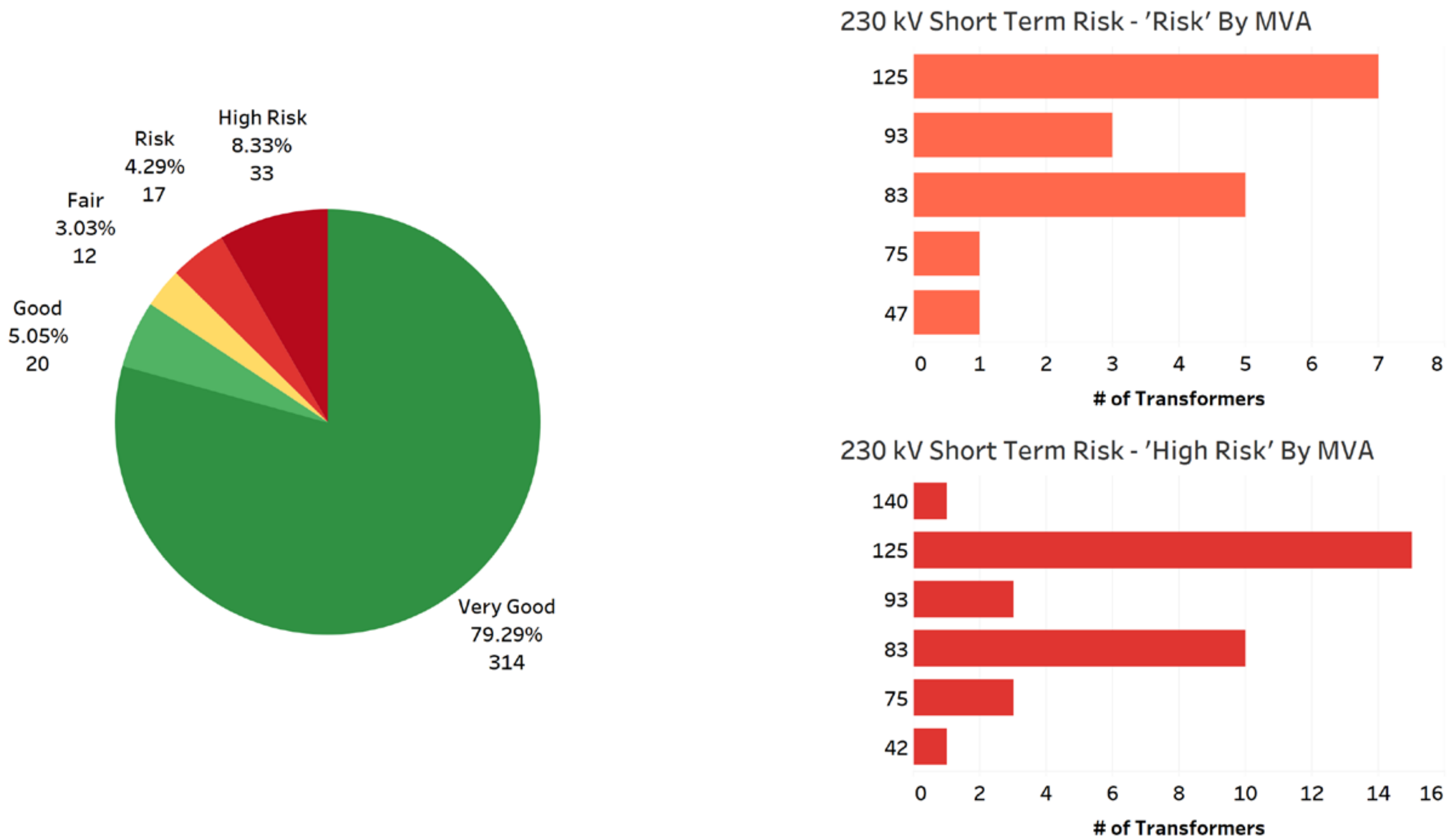


Figure 4-8
230 kV Short-Term Risk Transformers in “Risk” and “High Risk” Categories by MVA

Note that differences in count between pie chart counts and ‘Risk’ and ‘High Risk’ MVA bar charts are due to units where MVA value was not available being omitted from the bar charts.

Figure 4-9 shows long-term and short-term risk for Hydro One's 345 kV units.

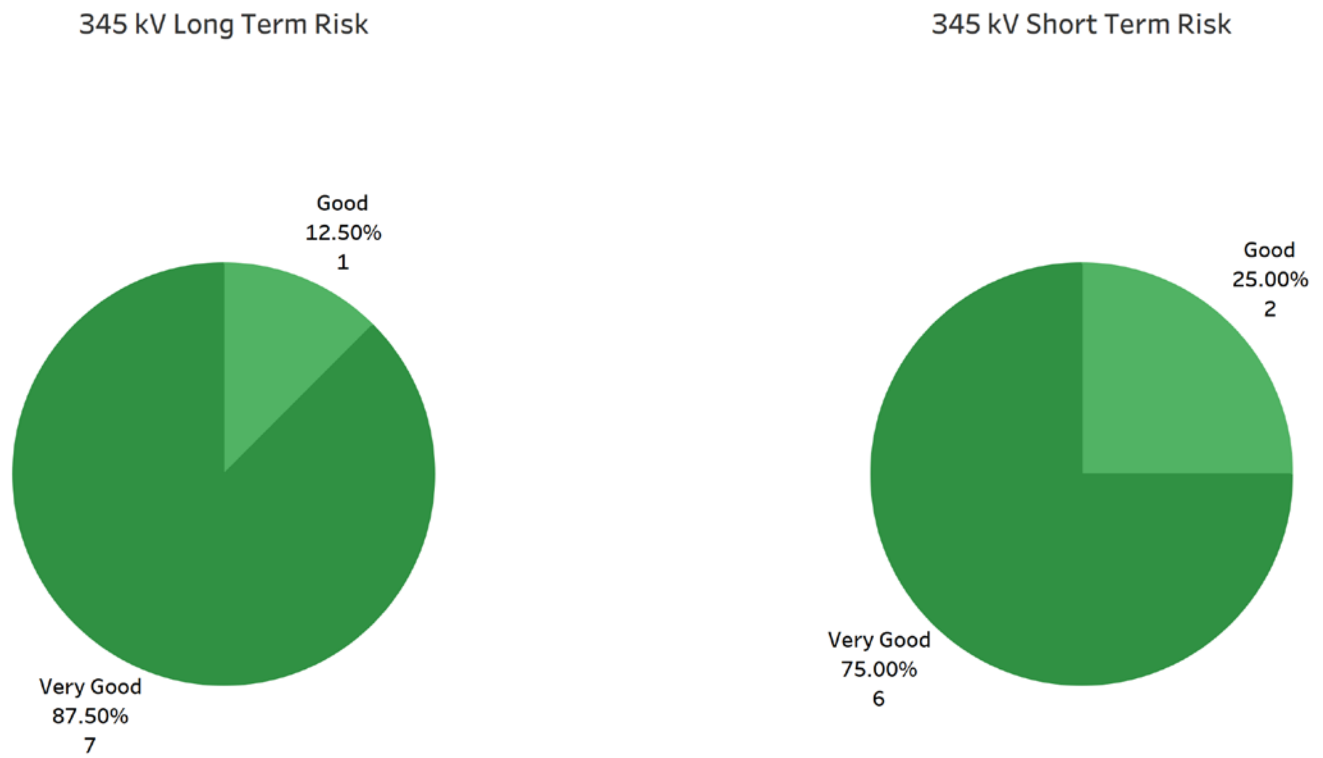


Figure 4-9
345 kV Units: Long-Term and Short-Term Risk

Figure 4-10 shows long-term and short-term risk for Hydro One's 500 kV units.

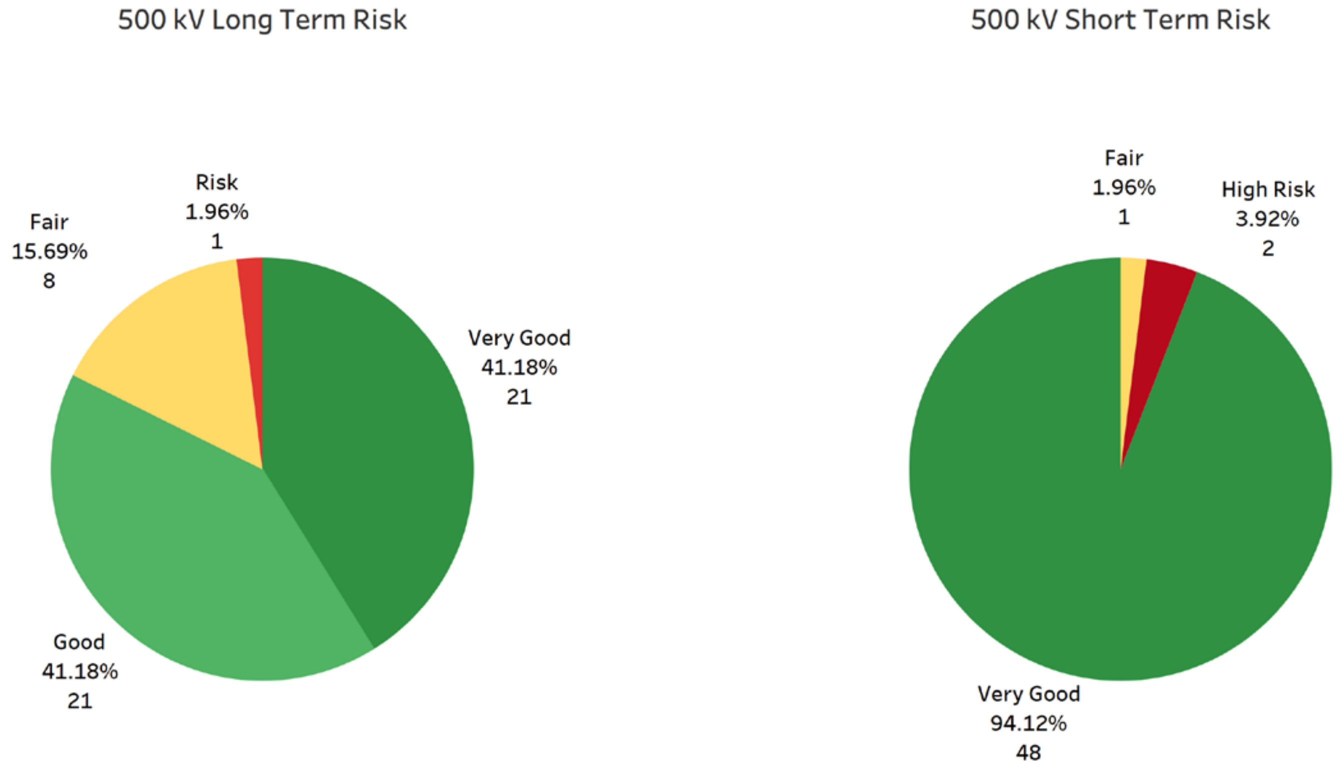
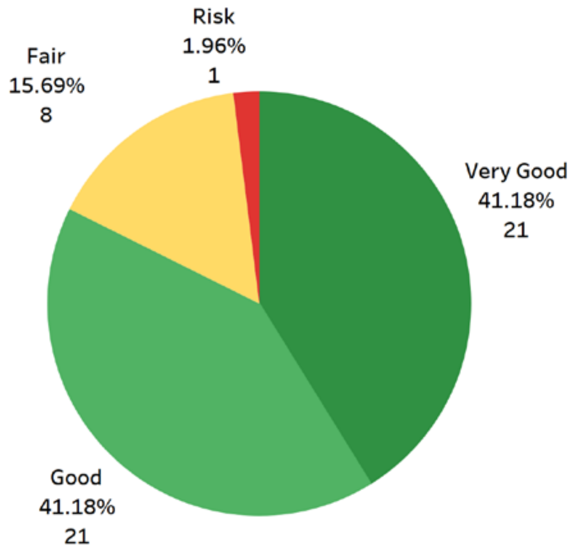


Figure 4-10
Short Term and Long-Term Risk for 500 kV Transformers

Figure 4-11 shows long-term risk transformers in the “Risk” category by MVA.



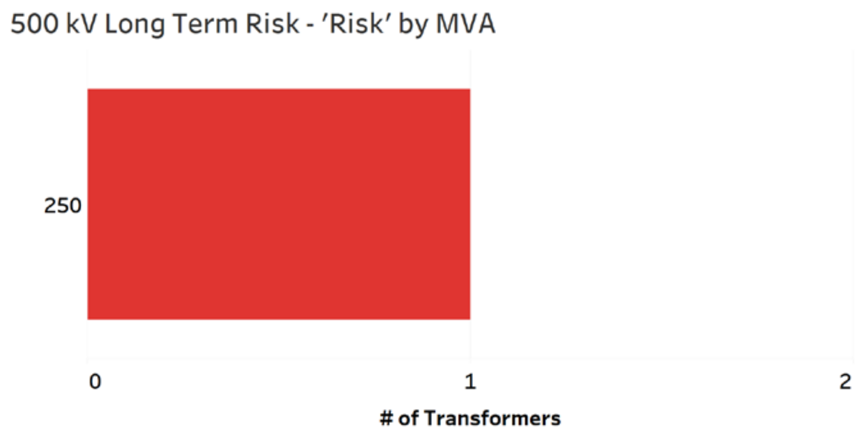
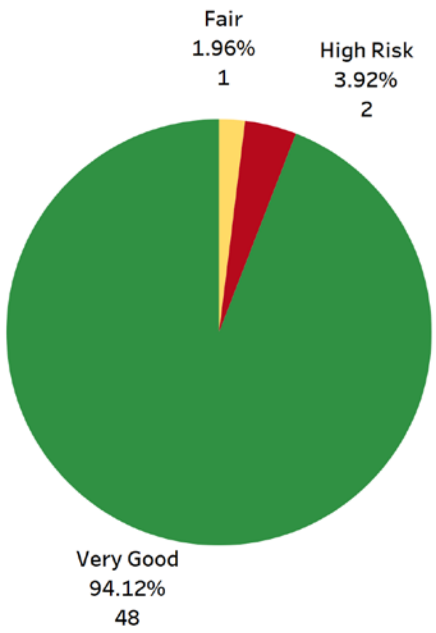


Figure 4-11
500 kV – Long-Term Risk – “Risk” Transformers by MVA

Figure 4-12 shows short-term risk transformers in the “High Risk” category by MVA.



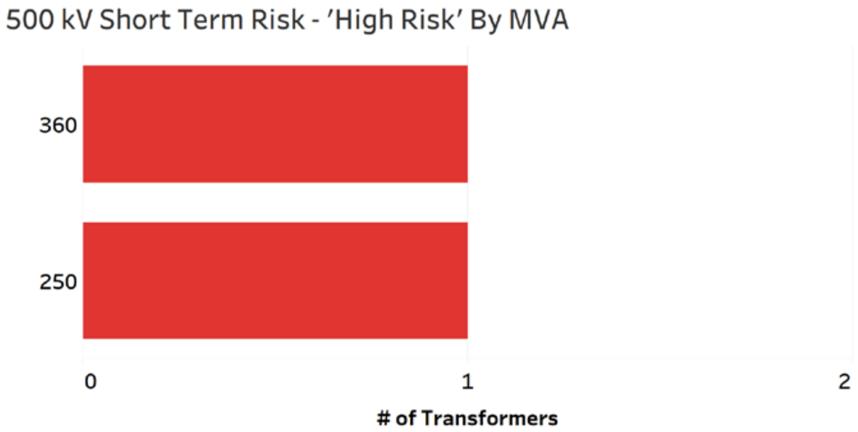


Figure 4-12
500 kV – Short-Term Risk – “High Risk” Transformers by MVA

As noted at the start of this chapter, the five-category ranking and graphical representations shown above constitute one possible approach to grouping transformers. Other combinations are possible, including grouping by voltages, station names, geographical regions, and criticality.

5
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A

HYDRO ONE ANALYSIS RESULTS SPREADSHEET

Appendix A presents the results of the Hydro One transformer analysis described in Chapter 3 ordered by normal degradation index.

Station	Designation	SAP Equipment Number	Vintage	Manufacturer	HV Voltage (kV)	Failure Consequence	Normal Degradation	NDI Data Quality	Abnormal Condition Code	Abnormal Thermal Code	Abnormal Electrical Code	Abnormal Core Code	Abnormal Index Data Quality	Oil Quality	Result Valid Until
Bridgman TS	STEPDN	1185926	1956	CGE*	110	0.28	0.78	Good	1	1	1	1	Good	0.59	11/14/2016
Gage TS	STEPDN	1177167	1948	CW*	110	0.26	0.77	Good	1	1	1	1	Good	0.21	1/9/2016
Newton TS	STEPDN	1191755	1956	CGE*	110	0.28	0.72	Good	1	1	1	1	Good	0.25	6/13/2016
John TS	STEPDN	1178381	1970	PION*	110	0.29	0.69	Good	2	2	1	1	Good	0	11/4/2016
Gage TS	STEPDN	1174569	1948	CW*	110	0.26	0.67	Good	5	1	5	1	Good	0.46	8/15/2016
Mohawk TS	STEPDN	1179178	1960	CGE*	110	0.28	0.66	Good	1	1	1	1	Good	0.87	11/10/2016
St.Thomas TS	STEPDN	1176786	1950	CW*	110	0.23	0.65	Good	1	1	1	1	Out of Date	0.26	5/23/2015
Cecil TS	STEPDN	1173028	1970	PION*	110	0.29	0.63	Good	1	1	1	1	Good	0	2/11/2016
Martindale TS	AUTO	1191766	1956	EE*	228.8	0.54	0.63	Good	1	1	1	1	Good	0.63	4/29/2016
Port Hope TS	STEPDN	1189649	1959	CW*	110	0.3	0.62	Good	1	1	1	1	Good	0.25	4/5/2016
Carlton TS	STEPDN	1188149	1953	CW*	110	0.23	0.61	Good	1	1	1	1	Good	0.9	4/22/2016
Wilson TS	STEPDN	1183712	1967	CW*	220	0.56	0.6	Good	3	2	3	2	Good	0.19	2/18/2016
Algoma TS	AUTO	1189015	1948	CGE*	228.8	0.54	0.6	Good	1	1	1	1	Good	0	6/8/2016
Port Hope TS	STEPDN	1187298	1959	CW*	110	0.3	0.59	Good	2	2	2	2	Good	0	8/19/2016
Manby TS	STEPDN	1180823	1967	CW*	220	0.5	0.57	Good	5	2	5	2	Good	0	2/2/2016
Elgin TS	STEPDN	1184380	1956	EE*	110	0.23	0.55	Good	1	1	1	1	Good	0.93	8/25/2016
Gage TS	STEPDN	1177117	1942	CW*	110	0.26	0.53	Good	1	1	1	1	Good	0.93	6/27/2016
Slater TS	STEPDN	1177732	1961	CW*	110	0.28	0.51	Good	5	2	5	3	Good	0	8/26/2016
Dufferin TS	STEPDN	1175626	1964	CW*	110	0.3	0.5	Good	4	2	4	1	Good	0	11/18/2016
Dobbin TS	AUTO	1182260	1951	CGE*	228.8	0.54	0.5	Good	1	1	1	1	Good	0.12	2/3/2016
Bilberry Creek TS	STEPDN	1185791	1961	CW*	110	0.3	0.48	Good	2	2	1	1	Good	0	3/8/2016
Centralia TS	STEPDN	1175510	1951	CW*	110	0.23	0.48	Good	1	1	1	1	Good	0.72	4/26/2016
Newton TS	STEPDN	1179202	1956	CGE*	110	0.28	0.47	Good	1	1	1	1	Good	0	6/13/2016
Fairbank TS	STEPDN	1180943	1959	CW*	110	0.3	0.47	Good	1	1	1	1	Good	0	2/19/2016
Manby TS	STEPDN	1172946	1967	CW*	220	0.5	0.46	Good	5	3	5	3	Good	0	12/1/2016
Kingsville TS	STEPDN	1187634	1951	CW*	110	0.24	0.46	Good	2	1	2	2	Good	0.6	12/13/2016
Slater TS	STEPDN	1172470	1968	CW*	110	0.27	0.46	Good	2	2	1	1	Good	0	10/21/2016
Overbrook TS	STEPDN	1185821	1962	FP*	110	0.28	0.45	Good	2	2	1	1	Good	0	3/22/2016
Otto Holden TS	AUTO	1188239	1950	CW*	230	0.46	0.45	Good	1	1	1	1	Out of Date	0.01	5/20/2015
Strachan TS	STEPDN	1188586	1956	CGE*	110	0.28	0.44	Good	1	1	1	1	Good	0.95	3/24/2016
Bermondsey TS	STEPDN	1178634	1965	CW*	210	0.55	0.43	Good	5	2	5	2	Good	0	10/28/2016
Keith TS	STEPDN	1185055	1957	CW*	110	0.24	0.43	Good	1	1	1	1	Out of Date	0.23	8/18/2015
Elgin TS	STEPDN	1176461	1956	EE*	110	0.23	0.43	Good	1	1	1	1	Good	0.46	3/4/2016
Essa TS	AUTO	1188969	1953	ASEA	228.8	0.54	0.42	Good	1	1	1	1	Good	0	3/23/2016
Algoma TS	AUTO	1184153	1956	EE*	228.8	0.67	0.42	Good	1	1	1	1	Good	0.8	11/16/2016
Lambton TS	STEPDN	1180151	1967	CW*	220	0.5	0.42	Good	1	1	1	1	Good	0.71	1/11/2016
Main TS	STEPDN	1178458	1968	PION*	110	0.29	0.42	Good	1	1	1	1	Good	0	4/20/2016
Essa TS	AUTO	1184073	1972	CGE*	500	1	0.41	Good	1	1	1	1	Good	0	3/24/2016
Otto Holden TS	AUTO	1190915	1953	CW*	230	0.46	0.41	Good	1	1	1	1	Out of Date	0.07	5/20/2015
Chenaux TS	AUTO	1190650	1951	CGE*	228.8	0.54	0.41	Good	1	1	1	1	Good	0.9	4/21/2016
Chenaux TS	AUTO	1190662	1948	CW*	228.8	0.5	0.41	Good	1	1	1	1	Good	0	4/21/2016
Runnymede TS	STEPDN	1175672	1962	CW*	110	0.32	0.4	Good	2	2	2	2	Good	0.55	2/4/2016
Fairbank TS	STEPDN	1180920	1959	CW*	110	0.3	0.4	Good	1	1	1	1	Good	0.3	2/19/2016
Wanstead TS	STEPDN	1185557	1950	CW*	110	0.23	0.4	Good	1	1	1	1	Good	0.42	2/3/2016
Wanstead TS	STEPDN	1180498	1951	CW*	110	0.22	0.4	Good	1	1	1	1	Good	0.04	2/3/2016
Palmerston TS	STEPDN	1175495	1951	CGE*	110	0.24	0.4	Good	1	1	1	1	Good	0.93	6/23/2016
Slater TS	STEPDN	1175172	1968	CW*	110	0.27	0.39	Good	2	2	2	2	Good	0	4/4/2016
Elgin TS	STEPDN	1191689	1970	PION*	110	0.29	0.39	Good	1	1	1	1	Good	0.48	5/26/2016
Hanmer TS	AUTO	1181913	1972	CGE*	500	1	0.39	Marginal	1	1	1	1	Good	0	5/25/2016
Keith TS	AUTO	1171927	1951	CGE*	228.8	0.54	0.39	Good	1	1	1	1	Good	0.93	6/29/2016
Frontenac TS	STEPDN	1192183	1977	CW*	216	0.48	0.39	Good	1	1	1	1	Good	0	2/8/2016
Kingsville TS	STEPDN	1172026	1952	CGE*	110	0.24	0.38	Good	2	2	2	2	Good	0.62	10/19/2016
Arnprior TS	STEPDN	1172361	1957	CGE*	110	0.24	0.38	Good	1	1	1	1	Good	0.24	3/30/2016
Hanlon TS	STEPDN	1175324	1955	EE*	110	0.23	0.38	Good	1	1	1	1	Good	0.9	6/24/2016
Goderich TS	STEPDN	1183363	1949	CGE*	110	0.22	0.38	Good	1	1	1	1	Good	0	8/22/2016
Bridgman TS	STEPDN	1188441	1956	CGE*	110	0.28	0.37	Good	5	2	5	3	Good	0.43	11/16/2016
Beach TS	AUTO	1186846	1965	CW*	236.8	0.82	0.37	Good	1	1	1	1	Good	0	5/9/2016
Otto Holden TS	AUTO	1183240	1950	CW*	230	0.46	0.37	Good	1	1	1	1	Out of Date	0	5/20/2015
Beach TS	STEPDN	1179124	1956	CGE*	110	0.29	0.37	Good	1	1	1	1	Good	0.04	5/20/2016
John TS	STEPDN	1183568	1968	PION*	110	0.29	0.36	Good	1	1	1	1	Good	0.14	4/10/2016
Murray TS	STEPDN	1188090	1974	CW*	110	0.29	0.36	Good	1	1	1	1	Good	0	3/21/2016
Otto Holden TS	AUTO	1178135	1953	CW*	230	0.46	0.36	Good	1	1	1	1	Out of Date	0.05	5/20/2015
Wanstead TS	STEPDN	1182958	1949	CW*	110	0.23	0.36	Good	1	1	1	1	Good	0.02	2/3/2016
Stanley TS	STEPDN	1180599	1958	CGE*	110	0.28	0.35	Good	5	2	5	2	Good	0.9	7/27/2016
Talbot TS	STEPDN	1188916	1979	CW*	215.5	0.53	0.35	Good	2	1	2	2	Good	0	6/7/2016
Hanmer TS	AUTO	1176643	1972	CW*	500	1	0.35	Good	5	2	5	1	Out of Date	0.06	9/4/2015
Mohawk TS	STEPDN	1189295	1960	CGE*	110	0.28	0.35	Good	1	1	1	1	Good	0.95	8/25/2016
Wilson TS	STEPDN	1175751	1970	PION*	215.5	0.53	0.35	Good	1	1	1	1	Good	0	2/18/2016
Lake TS	STEPDN	1181618	1971	CW*	216	0.48	0.34	Good	1	1	1	1	Good	0.26	5/5/2016
Fairbank TS	STEPDN	1188527	1959	CW*	110	0.3	0.33	Good	1	1	1	1	Good	0.38	2/19/2016

Station	Designation	SAP Equipment Number	Vintage	Manufacturer	HV Voltage (kV)	Failure Consequence	Normal Degradation	NDI Data Quality	Abnormal Condition Code	Abnormal Thermal Code	Abnormal Electrical Code	Abnormal Core Code	Abnormal Index Data Quality	Oil Quality	Result Valid Until
Fort Frances TS	AUTO	1187772	1971	CGE*	232	0.56	0.33	Good	1	1	1	1	Good	0	4/21/2016
Finch TS	STEPDN	1186403	1986	CW*	215.5	0.53	0.33	Good	1	1	1	1	Good	0	8/5/2016
Buchanan TS	AUTO	1183350	1968	CGE*	236.8	0.78	0.33	Good	1	1	1	1	Good	0.12	8/10/2016
Glendale TS	STEPDN	1175414	1951	CW*	110	0.22	0.33	Good	1	1	1	1	Good	0.9	8/4/2016
Claireville TS	AUTO	1182668	1980	CGE*	500	1	0.33	Good	1	1	1	1	Good	0.47	9/15/2016
Palmerston TS	STEPDN	1190983	1955	BRBO*	110	0.24	0.32	Good	3	2	3	2	Good	0.33	6/27/2016
Aylmer TS	STEPDN	1183334	1948	CGE*	110	0.22	0.32	Good	1	1	1	1	Good	0	5/31/2016
Runnymede TS	STEPDN	1186109	1962	CW*	110	0.32	0.31	Good	2	2	2	2	Good	0	2/4/2016
Porcupine TS	AUTO	1174142	1967	CW*	480	1	0.31	Marginal	1	1	1	1	Good	0	10/24/2016
St.Thomas TS	STEPDN	1189560	1950	CW*	110	0.23	0.31	Good	1	1	1	1	Good	0.96	7/17/2016
Carlton TS	STEPDN	1188157	1948	EE*	110	0.23	0.31	Good	1	1	1	1	Good	0.67	4/21/2016
N.R.C. TS	STEPDN	1185768	1952	CW*	110	0.23	0.31	Good	1	1	1	1	Good	0.71	3/3/2016
Finch TS	STEPDN	1178751	1988	TTI*	215.5	0.53	0.31	Good	1	1	1	1	Out of Date	0.28	5/27/2015
Hanmer TS	AUTO	1187048	1972	CGE*	500	1	0.31	Marginal	1	1	1	1	Good	0	6/13/2017
Elliot Lake TS	STEPDN	1184202	1948	CGE*	110	0.23	0.31	Good	1	1	1	1	Good	0.9	8/12/2016
Orangeville TS	STEPDN	1182594	1964	CW*	210	0.52	0.3	Good	2	2	2	2	Good	0	2/19/2016
Glendale TS	STEPDN	1175401	1967	FP*	115.5	0.3	0.3	Good	1	1	1	1	Good	0	8/4/2016
Hawthorne TS	AUTO	1182896	1960	CGE*	236.8	0.74	0.3	Good	1	1	1	1	Good	0.04	5/2/2016
Aylmer TS	STEPDN	1172896	1951	CGE*	110	0.22	0.3	Good	1	1	1	1	Good	0.65	5/31/2016
Orangeville TS	STEPDN	1180187	1964	CW*	210	0.52	0.29	Good	5	2	5	3	Good	0.69	5/2/2016
Hanlon TS	STEPDN	1190770	1956	EE*	110	0.23	0.29	Good	1	1	1	1	Good	0.86	6/24/2016
Glendale TS	STEPDN	1188168	1951	CW*	110	0.22	0.29	Good	1	1	1	1	Good	0.43	8/29/2016
N.R.C. TS	STEPDN	1185780	1952	CW*	110	0.23	0.29	Good	1	1	1	1	Good	0.76	3/3/2016
Mackenzie TS	AUTO	1190374	1971	CGE*	232	0.56	0.29	Good	1	1	1	1	Good	0.05	6/1/2016
Middleport TS	AUTO	1178054	1974	CW*	500	1	0.29	Good	1	1	1	1	Good	0.25	10/4/2016
Terauley TS	STEPDN	1232226	1977	PION*	110	0.38	0.29	Marginal	1	1	1	1	Good	0	3/21/2016
Bruce A TS	AUTO	1184740	1981	CGE*	500	1	0.29	Good	1	1	1	1	Good	0	12/5/2016
Woodbridge TS	STEPDN	1183214	1972	CW*	215.5	0.53	0.28	Good	5	2	5	3	Good	0.2	6/9/2016
Lambton TS	STEPDN	1171986	1967	CW*	220	0.5	0.28	Good	5	2	5	3	Good	0	10/18/2016
Havelock TS	STEPDN	1182283	1964	CGE*	235	0.52	0.28	Good	4	2	4	3	Good	0.45	2/10/2016
Hawthorne TS	STEPDN	1172380	1969	EE*	220	0.49	0.28	Good	1	1	1	1	Good	0	5/2/2016
Fairchild TS	STEPDN	1175893	1968	CGE*	220	0.54	0.28	Good	1	1	1	1	Good	0	1/18/2016
Cedar TS	STEPDN	1190760	1958	CGE*	110	0.24	0.27	Good	1	1	1	1	Good	0.94	6/24/2016
Middleport TS	AUTO	1185731	1972	CW*	500	1	0.27	Good	1	1	1	1	Out of Date	0.07	3/2/2015
Centralia TS	STEPDN	1175522	1951	CGE*	110	0.23	0.27	Good	1	1	1	1	Good	0.17	4/26/2016
Keith TS	AUTO	1182528	1953	CGE*	228.8	0.54	0.27	Good	1	1	1	1	Good	0	6/16/2016
Charles TS	STEPDN	1191105	1990	PION*	110	0.33	0.27	Good	1	1	1	1	Good	0	1/10/2016
Beach TS	AUTO	1184340	1965	CW*	236.8	0.82	0.27	Good	1	1	1	1	Good	0.04	9/19/2016
Warden TS	STEPDN	1173322	1987	TTI*	215.5	0.53	0.27	Good	1	1	1	1	Good	0	4/13/2016
Palmerston TS	STEPDN	1172883	1950	CGE*	110	0.24	0.27	Good	1	1	1	1	Good	0	4/1/2016
Sheppard TS	STEPDN	1181138	1962	FP*	210	0.47	0.26	Good	5	2	5	3	Good	0	11/22/2016
Sheppard TS	STEPDN	1175789	1962	FP*	210	0.47	0.26	Good	5	2	5	2	Good	0	9/26/2016
Parry Sound TS	STEPDN	1186707	1969	CW*	220	0.45	0.26	Good	3	2	3	2	Good	0	6/7/2016
Duplex TS	STEPDN	1185957	1966	CGE*	110	0.29	0.26	Good	3	2	3	2	Good	0.14	3/18/2016
Lake TS	STEPDN	1184406	1982	CGE*	215.5	0.47	0.26	Good	1	1	1	1	Good	0.06	9/7/2016
Esplanade TS	STEPDN	1185986	1987	TTI*	110	0.33	0.26	Good	1	1	1	1	Good	0	2/26/2016
Detweiler TS	AUTO	1172587	1963	CW*	236.8	0.74	0.26	Good	1	1	1	1	Good	0	6/20/2016
Russell TS	STEPDN	1177708	1971	FP*	110	0.29	0.26	Good	1	1	1	1	Good	0	3/24/2016
Scarboro TS	STEPDN	1181055	1992	PION*	215.5	0.53	0.26	Good	1	1	1	1	Good	0	8/23/2016
Cedar TS	STEPDN	1177852	1958	CGE*	110	0.24	0.26	Good	1	1	1	1	Good	0.9	6/24/2016
Kenilworth TS	STEPDN	1191710	1957	CGE*	110	0.28	0.26	Good	1	1	1	1	Good	0.32	7/19/2016
Crawford TS	STEPDN	1180034	1975	CW*	115	0.31	0.26	Good	1	1	1	1	Good	0	9/16/2016
Bilberry Creek TS	STEPDN	1188268	1961	CW*	110	0.3	0.25	Good	3	2	3	2	Good	0	3/8/2016
Bermondsey TS	STEPDN	1181093	1965	CW*	210	0.52	0.25	Good	3	2	3	2	Good	0	3/10/2016
Elgin TS	STEPDN	1181559	1967	FP*	115.5	0.3	0.25	Good	2	2	1	1	Good	0.01	12/29/2016
Elliot Lake TS	STEPDN	1181466	1957	CGE*	110	0.24	0.25	Good	1	1	1	1	Good	0.34	8/12/2016
John TS	STEPDN	1186027	1985	CGE*	110	0.29	0.25	Good	1	1	1	1	Good	0	3/4/2016
Moose Lake TS	STEPDN	1177628	1948	CGE*	110	0.22	0.25	Good	1	1	1	1	Good	0.08	4/29/2016
Lake TS	STEPDN	1181595	1982	CGE*	215.5	0.47	0.25	Good	1	1	1	1	Good	0.13	12/16/2016
Hanover TS	STEPDN	1179602	1959	CW*	110	0.3	0.24	Good	5	4	5	3	Good	0.94	9/16/2016
Cataraqui TS	AUTO	1176942	1968	CGE*	236.8	0.78	0.24	Good	1	1	1	1	Good	0	2/29/2016
Coniston TS	STEPDN	1184561	1940	EE*	110	0.22	0.24	Good	1	1	1	1	Good	0.25	4/25/2016
Dobbin TS	AUTO	1184792	1960	CGE*	236.8	0.78	0.24	Good	1	1	1	1	Good	0	2/3/2016
Lorne Park TS	STEPDN	1252036	2008	HYUNDAI*	215.5	0.53	0.24	Good	1	1	1	1	Good	0	10/27/2016
Basin TS	STEPDN	1175581	1981	CW*	110	0.29	0.24	Good	1	1	1	1	Good	0.3	4/18/2016
Otto Holden TS	AUTO	1183229	1950	CW*	230	0.46	0.24	Good	1	1	1	1	Good	0	4/20/2016
Otonabee TS	STEPDN	1189639	1989	ABB	215.5	0.53	0.24	Good	1	1	1	1	Good	0	2/17/2016
Essa TS	AUTO	1184086	1972	CGE*	500	1	0.24	Good	1	1	1	1	Out of Date	0.63	9/24/2015
Manby TS	AUTO	1191072	1968	CGE*	236.8	0.78	0.24	Good	1	1	1	1	Good	0	9/20/2016
Essa TS	AUTO	1186677	1972	CGE*	500	1	0.24	Good	1	1	1	1	Out of Date	0	9/24/2015

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Esplanade TS	STEPDN	1180906	1987	TTI*	110	0.33	0.24	Good	1	1	1	1	Good	0.25	4/1/2016
Barrie TS	STEPDN	1176173	1962	CW*	110	0.32	0.23	Good	5	2	5	3	Good	0.1	5/5/2016
Armitage TS	STEPDN	1183646	1978	CW*	215.5	0.53	0.23	Good	5	2	5	3	Good	0.59	11/9/2016
Charles TS	STEPDN	1178289	1966	CGE*	110	0.29	0.23	Good	4	2	4	2	Good	0.28	2/20/2016
Belleville TS	STEPDN	1179679	1967	CW*	220	0.56	0.23	Good	2	2	2	2	Good	0.55	2/23/2016
Kenora TS	AUTO	1182784	1971	CGE*	232	0.56	0.23	Good	1	1	1	1	Good	0	5/18/2016
Manby TS	AUTO	1178275	1968	CGE*	236.8	0.78	0.23	Good	1	1	1	1	Good	0	2/2/2016
Erindale TS	STEPDN	1246018	1979	CGE*	215.5	0.53	0.23	Good	1	1	1	1	Out of Date	0	1/12/2015
Esplanade TS	STEPDN	1183501	1989	PION*	110	0.33	0.23	Good	1	1	1	1	Good	0	5/11/2016
Preston TS	STEPDN	1172127	1968	CGE*	220	0.54	0.23	Good	1	1	1	1	Good	0	6/24/2016
Glendale TS	STEPDN	1172725	1993	ABB	110	0.29	0.23	Good	1	1	1	1	Good	0	8/4/2016
Middleport TS	AUTO	1183169	1972	CW*	500	1	0.23	Good	1	1	1	1	Out of Date	0.19	3/2/2015
Minden TS	STEPDN	1177826	1956	ASEA	230	0.47	0.23	Good	1	1	1	1	Good	0.84	1/11/2016
Seaforth TS	AUTO	1189547	1969	CGE*	236.8	0.78	0.23	Good	1	1	1	1	Good	0.1	3/11/2016
Rexdale TS	STEPDN	1178812	1988	TTI*	215.5	0.53	0.23	Good	1	1	1	1	Good	0.93	10/25/2016
Middleport TS	AUTO	1180663	1972	CW*	500	1	0.23	Good	1	1	1	1	Good	0.28	2/8/2016
Bronte TS	STEPDN	1183968	1962	CGE*	110	0.32	0.23	Good	1	1	1	1	Good	0.15	1/6/2016
Woodbridge TS	STEPDN	1172754	1989	ABB	215.5	0.53	0.23	Good	1	1	1	1	Good	0	5/18/2016
Rexdale TS	STEPDN	1173431	1988	TTI*	215.5	0.53	0.23	Good	1	1	1	1	Good	0	10/25/2016
Terauley TS	STEPDN	1183602	1976	FP*	110	0.38	0.23	Good	1	1	1	1	Good	0	3/16/2016
Stirton TS	STEPDN	1182398	1989	PION*	110	0.29	0.23	Good	1	1	1	1	Good	0	6/19/2016
St.Andrews TS	STEPDN	1175199	1964	CW*	110	0.32	0.22	Good	3	2	3	2	Good	0.03	2/3/2016
South March TS	STEPDN	1191351	1970	CGE*	215.5	0.48	0.22	Good	3	2	3	2	Good	0.56	3/16/2016
Richview TS	STEPDN	1178682	1969	CW*	220	0.54	0.22	Good	2	2	2	1	Out of Date	0.05	7/28/2015
Hanmer TS	AUTO	1251688	2006	HYUNDAI*	500	1	0.22	Marginal	1	1	1	1	Good	0	8/11/2016
Manby TS	AUTO	1178262	1969	CGE*	236.8	0.78	0.22	Good	1	1	1	1	Good	0	2/2/2016
Campbell TS	STEPDN	1188060	1989	PION*	215.5	0.47	0.22	Good	1	1	1	1	Good	0.18	9/12/2016
Bronte TS	STEPDN	1188941	1962	CGE*	110	0.32	0.22	Good	1	1	1	1	Good	0	1/6/2016
Preston TS	STEPDN	1172094	1968	CGE*	220	0.54	0.22	Good	1	1	1	1	Good	0	6/24/2016
Warden TS	STEPDN	1181150	1987	TTI*	215.5	0.53	0.22	Good	1	1	1	1	Good	0	12/8/2016
Fort Frances TS	AUTO	1180344	1971	CGE*	232	0.56	0.22	Good	1	1	1	1	Good	0.13	4/21/2016
Martindale TS	AUTO	1173985	1969	CGE*	236.8	0.57	0.22	Good	1	1	1	1	Good	0.63	4/29/2016
Leslie TS	STEPDN	1186267	1988	TTI*	215.5	0.53	0.22	Good	1	1	1	1	Good	0	4/19/2016
Fairchild TS	STEPDN	1173362	1968	CGE*	220	0.54	0.21	Good	5	2	5	3	Good	0	12/20/2016
Carlaw TS	STEPDN	1173017	1974	PION*	110	0.29	0.21	Good	4	2	4	2	Good	0	4/7/2016
Bathurst TS	STEPDN	1191340	1969	CW*	220	0.54	0.21	Good	3	2	3	2	Good	0.04	2/8/2016
Duplex TS	STEPDN	1175638	1966	CGE*	110	0.29	0.21	Good	3	2	3	2	Good	0.25	3/8/2016
Erindale TS	STEPDN	1177472	1980	CGE*	215.5	0.53	0.21	Good	4	4	4	1	Good	0	10/14/2016
Dufferin TS	STEPDN	1188489	1964	CW*	110	0.3	0.21	Good	3	2	3	1	Good	0	2/8/2016
Martindale TS	STEPDN	1174004	1970	PION*	215.5	0.53	0.21	Good	1	1	1	1	Good	0	7/4/2016
Longwood TS	AUTO	1184712	1990	TTI*	500	1	0.21	Good	1	1	1	1	Good	0	6/21/2016
Strachan TS	STEPDN	1175696	1981	CW*	110	0.29	0.21	Good	1	1	1	1	Good	0	2/18/2016
Duplex TS	STEPDN	1185969	1974	CW*	110	0.29	0.21	Good	1	1	1	1	Good	0	10/13/2016
Strathroy TS	STEPDN	1247079	2008	ENERCO*	110	0.24	0.21	Good	1	1	1	1	Good	0	10/27/2016
Waubaushene TS	STEPDN	1178982	1972	CGE*	215.5	0.48	0.21	Good	1	1	1	1	Good	0	7/20/2016
Muskoka TS	STEPDN	1176203	1991	PION*	215.5	0.53	0.21	Good	1	1	1	1	Good	0.9	4/27/2016
Parry Sound TS	STEPDN	1173626	1969	CW*	220	0.45	0.21	Good	1	1	1	1	Good	0	6/8/2016
Lauzon TS	STEPDN	1182581	1972	CW*	215.5	0.48	0.2	Good	5	2	5	3	Good	0	4/13/2016
Bramalea TS	STEPDN	1180248	1970	CGE*	215.5	0.48	0.2	Good	5	2	5	2	Good	0.04	2/26/2016
Bramalea TS	STEPDN	1174870	1970	CGE*	215.5	0.48	0.2	Good	5	2	5	2	Good	0.84	5/12/2016
Horner TS	STEPDN	1173083	1986	CGE*	215.5	0.53	0.2	Good	1	1	1	1	Good	0	1/27/2016
Bathurst TS	STEPDN	1181166	1987	TTI*	215.5	0.53	0.2	Good	1	1	1	1	Good	0.57	2/8/2016
Burlington TS	STEPDN	1181477	1991	ABB	215.5	0.53	0.2	Good	1	1	1	1	Good	0	3/8/2016
Vansickle TS	STEPDN	1251531	2004	HYUNDAI*	110	0.29	0.2	Marginal	1	1	1	1	Good	0	11/23/2016
Woodroffe TS	STEPDN	1251761	2009	HYUNDAI*	110	0.29	0.2	Good	1	1	1	1	Good	0	8/22/2016
Pleasant TS	STEPDN	1176007	1988	TTI*	215.5	0.53	0.2	Good	1	1	1	1	Good	0	10/28/2016
Tomken TS	STEPDN	1178824	1971	PION*	215.5	0.53	0.2	Good	1	1	1	1	Good	0.1	4/13/2016
Leaside TS	AUTO	1186056	1982	ASEA	236.8	0.78	0.2	Good	1	1	1	1	Good	0	1/29/2016
Woodroffe TS	STEPDN	1251760	2009	HYUNDAI*	110	0.29	0.2	Good	1	1	1	1	Good	0	3/17/2016
Cataraqui TS	AUTO	1189690	1968	CGE*	236.8	0.78	0.2	Good	1	1	1	1	Good	0.13	2/29/2016
Finch TS	STEPDN	1368367	2010	HYUNDAI*	215.5	0.53	0.2	Good	1	1	1	1	Good	0	7/27/2016
Walker TS #1	STEPDN	1190123	1971	CW*	216	0.48	0.19	Good	5	2	5	3	Good	0	1/22/2016
Havelock TS	STEPDN	1179717	1964	CGE*	235	0.52	0.19	Good	4	2	4	3	Good	0	2/10/2016
Fergus TS	STEPDN	1188044	1972	PION*	215.5	0.53	0.19	Good	4	2	4	2	Good	0	6/24/2016
Lambton TS #2	AUTO	1180127	1968	PEEB*	346	1	0.19	Good	2	1	2	2	Good	0	1/11/2016
Erindale TS	STEPDN	1172173	1980	CGE*	215.5	0.53	0.19	Good	1	1	1	1	Good	0	5/2/2016
Thorold TS	STEPDN	1178007	1970	PION*	110	0.29	0.19	Good	1	1	1	1	Good	0.83	4/13/2016
John TS	STEPDN	1178371	1976	FP*	110	0.38	0.19	Good	1	1	1	1	Good	0	3/4/2016
Manby TS	AUTO	1172959	1990	PION*	236.8	0.78	0.19	Good	1	1	1	1	Good	0.48	2/2/2016
Bramalea TS	STEPDN	1946120	2010	HYUNDAI*	215.5	0.53	0.19	Good	1	1	1	1	Good	0	3/18/2016

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Burlington TS	AUTO	1186817	1989	PION*	236.8	0.78	0.19	Good	1	1	1	1	Good	0	12/11/2016
Port Colborne TS	STEPDN	1177205	1963	CGE*	110	0.25	0.19	Good	1	1	1	1	Good	0.5	7/27/2016
Birmingham TS	STEPDN	1248413	2008	HYUNDAI*	110	0.29	0.19	Good	1	1	1	1	Good	0	1/11/2016
Moose Lake TS	STEPDN	1185358	1948	CGE*	110	0.22	0.19	Good	1	1	1	1	Good	0.7	4/29/2016
Glengrove TS	STEPDN	1251740	2009	PAUW*	115.5	0.25	0.19	Good	1	1	1	1	Good	0.12	8/8/2016
Bathurst TS	STEPDN	1178724	1987	TTI*	215.5	0.53	0.19	Good	1	1	1	1	Out of Date	0	5/14/2015
Riverdale TS	STEPDN	1172426	1988	PION*	110	0.29	0.19	Good	1	1	1	1	Good	0.05	3/23/2016
Dufferin TS	STEPDN	1175611	1974	CW*	110	0.29	0.19	Good	1	1	1	1	Good	0.12	3/22/2016
Bridgman TS	STEPDN	1175592	1958	CGE*	110	0.28	0.19	Good	1	1	1	1	Good	0.12	6/3/2016
Kingsville TS	STEPDN	1174770	1959	CGE*	110	0.24	0.19	Good	1	1	1	1	Out of Date	0.63	9/9/2015
Murray TS	STEPDN	1175366	1973	FP*	110	0.29	0.19	Good	1	1	1	1	Good	0	5/13/2016
Leaside TS	AUTO	1186067	1982	ASEA	236.8	0.78	0.19	Good	1	1	1	1	Good	0	1/28/2016
Lauzon TS	AUTO	1180175	1968	CGE*	236.8	0.78	0.19	Good	1	1	1	1	Good	0	12/7/2016
Wonderland TS	STEPDN	1179452	2004	HYUNDAI*	215.5	0.48	0.19	Good	1	1	1	1	Good	0	11/18/2016
Halton TS	STEPDN	1182687	1989	ABB	215.5	0.53	0.19	Good	1	1	1	1	Good	0	3/1/2016
Clarke TS	STEPDN	1175559	1969	CW*	220	0.49	0.18	Good	5	2	5	3	Good	0.32	2/20/2016
St.Andrews TS	STEPDN	1190638	1964	CW*	110	0.32	0.18	Good	4	2	4	3	Good	0	2/3/2016
Fairchild TS	STEPDN	1178740	1979	CW*	215.5	0.53	0.18	Good	4	2	4	2	Good	0	2/26/2016
Charles TS	STEPDN	1183465	1966	CGE*	110	0.29	0.18	Good	4	2	4	2	Good	0.11	6/14/2016
Hawthorne TS	STEPDN	1187915	1969	EE*	220	0.49	0.18	Good	2	2	1	1	Good	0	5/2/2016
Owen Sound TS	STEPDN	1182248	1979	CGE*	215.5	0.53	0.18	Good	1	1	1	1	Good	0.78	8/23/2016
Tilbury TS	STEPDN	1185141	1951	CGE*	110	0.22	0.18	Good	1	1	1	1	Good	0.15	3/2/2016
Armitage TS	STEPDN	1178554	1979	CGE*	215.5	0.53	0.18	Good	1	1	1	1	Good	0.04	11/9/2016
Cecil TS	STEPDN	1191093	1991	PION*	110	0.33	0.18	Marginal	1	1	1	1	Good	0	1/20/2016
Allanburg TS	AUTO	1184019	1981	CW*	236.8	0.78	0.18	Good	1	1	1	1	Good	0.35	5/31/2016
Port Colborne TS	STEPDN	1182410	1963	CGE*	110	0.25	0.18	Good	1	1	1	1	Good	0.62	7/27/2016
Beach TS	STEPDN	1184319	1959	CW*	110	0.28	0.18	Good	1	1	1	1	Good	0	11/16/2016
Erindale TS	STEPDN	1177483	1980	CGE*	215.5	0.53	0.18	Good	1	1	1	1	Good	0.13	4/6/2016
Horner TS	STEPDN	1183539	1987	TTI*	215.5	0.53	0.18	Good	1	1	1	1	Good	0.71	1/27/2016
Strachan TS	STEPDN	1178497	1982	CW*	110	0.29	0.18	Good	1	1	1	1	Good	0	10/31/2016
Ellesmere TS	STEPDN	1251795	2009	HYUNDAI*	215.5	0.53	0.18	Good	1	1	1	1	Good	0	2/4/2016
Bathurst TS	STEPDN	1178709	1986	C&F*	215.5	0.53	0.18	Good	1	1	1	1	Good	0.05	2/8/2016
Nebo TS	STEPDN	1250583	2004	HYUNDAI*	215.5	0.53	0.18	Marginal	1	1	1	1	Good	0	11/18/2016
Kent TS	STEPDN	1182444	1974	PION*	215.5	0.53	0.18	Good	1	1	1	1	Good	0	3/16/2016
Oakville TS #2	STEPDN	1368536	2010	HYUNDAI*	215.5	0.53	0.18	Good	1	1	1	1	Good	0	2/12/2016
Sarnia Scott TS	AUTO	1188223	1958	CGE*	236.8	0.78	0.18	Good	1	1	1	1	Out of Date	0.37	1/21/2015
Fairbank TS	STEPDN	1180932	1959	CW*	110	0.3	0.18	Good	1	1	1	1	Good	0	2/19/2016
Dryden TS	STEPDN	1190323	1949	CGE*	110	0.22	0.18	Good	1	1	1	1	Good	0.13	4/6/2016
Birmingham TS	STEPDN	1248412	2008	HYUNDAI*	110	0.29	0.18	Good	1	1	1	1	Good	0.11	1/11/2016
Burlington TS	STEPDN	1191599	1991	ABB	215.5	0.53	0.18	Good	1	1	1	1	Good	0	4/11/2016
Lorne Park TS	STEPDN	1172238	1974	PION*	215.5	0.53	0.18	Good	1	1	1	1	Good	0	3/24/2016
Wingham TS	STEPDN	1181292	1965	EE*	235	0.51	0.17	Good	5	3	5	3	Good	0	5/4/2016
Nepean TS	STEPDN	1188312	1974	FP*	215.5	0.53	0.17	Good	5	3	5	3	Good	0	12/9/2016
Gardiner TS	STEPDN	1189748	1975	ASEA	215.5	0.53	0.17	Good	5	2	5	2	Good	0	10/17/2016
Scarboro TS	STEPDN	1173261	1969	CW*	220	0.54	0.17	Good	2	2	1	1	Good	0.88	4/21/2016
Buchanan TS	STEPDN	1172920	1988	TTI*	215.5	0.53	0.17	Good	1	1	1	1	Good	0	8/28/2016
Longueuil TS	STEPDN	1182299	1964	CGE*	235	0.52	0.17	Good	1	1	1	1	Good	0	2/5/2016
Hanover TS	STEPDN	1182230	1968	CW*	110	0.32	0.17	Good	1	1	1	1	Good	0.9	9/16/2016
Leaside TS	AUTO	1186080	1990	PION*	236.8	0.78	0.17	Good	1	1	1	1	Good	0	1/28/2016
Trafalgar TS	AUTO	1945856	2011	HYUNDAI*	500	1	0.17	Good	1	1	1	1	Good	0	9/22/2016
Gardiner TS	STEPDN	1184858	1974	FP*	215.5	0.53	0.17	Good	1	1	1	1	Good	0	4/6/2016
Buttonville TS	STEPDN	1188700	1979	CW*	215.5	0.53	0.17	Good	1	1	1	1	Good	0	8/2/2016
Waubaushene TS	STEPDN	1176228	1972	CGE*	215.5	0.48	0.17	Good	1	1	1	1	Good	0	1/26/2016
Claireville TS	AUTO	2767949	2012	HYUNDAI*	500	1	0.17	Good	1	1	1	1	Good	0.43	9/22/2016
Cherrywood TS	AUTO	1188721	2006	HYUNDAI*	500	1	0.17	Marginal	1	1	1	1	Good	0.45	5/6/2016
Finch TS	STEPDN	2386724	2010	HYUNDAI*	215.5	0.53	0.17	Good	1	1	1	1	Out of Date	0	5/25/2015
Clarabelle TS	STEPDN	1174016	1972	PION*	215.5	0.53	0.17	Good	1	1	1	1	Good	0.25	5/19/2016
Cedar TS	STEPDN	1185583	1996	PAUW*	110	0.29	0.17	Good	1	1	1	1	Good	0	12/8/2016
Murray TS	STEPDN	1190817	1971	FP*	110	0.29	0.17	Good	1	1	1	1	Good	0	9/12/2016
Keith TS	STEPDN	1245933	2004	HYUNDAI*	215.5	0.48	0.17	Marginal	1	1	1	1	Good	0	7/4/2016
Barrie TS	STEPDN	1178916	1962	CW*	110	0.32	0.17	Good	1	1	1	1	Good	0	3/4/2016
Stirton TS	STEPDN	1174602	1988	PION*	110	0.29	0.17	Good	1	1	1	1	Out of Date	0	3/11/2015
Hawthorne TS	AUTO	1175115	1960	CGE*	236.8	0.74	0.17	Good	1	1	1	1	Good	0	5/2/2016
Kleinburg TS	STEPDN	1177524	1989	TTI*	215.5	0.53	0.17	Good	1	1	1	1	Good	0	5/18/2016
Scarboro TS	STEPDN	1191258	1990	PION*	215.5	0.53	0.17	Good	1	1	1	1	Good	0	4/6/2016
Stratford TS	STEPDN	1192041	1987	TTI*	215.5	0.48	0.17	Good	1	1	1	1	Good	0.3	6/24/2016
Lauzon TS	STEPDN	1185131	1969	CW*	220	0.49	0.16	Good	5	3	5	4	Good	0.65	8/27/2016
South March TS	STEPDN	1178762	1970	CGE*	215.5	0.48	0.16	Good	3	2	3	2	Good	0.56	3/16/2016
Leaside TS	STEPDN	2376713	2010	CGPOWER*	225.75	0.5	0.16	Good	2	1	2	2	Good	0	11/15/2016
Campbell TS	STEPDN	1190722	1989	PION*	215.5	0.47	0.16	Good	1	1	1	1	Good	0.82	11/24/2016

Station	Designation	SAP Equipment Number	Vintage	Manufacturer	HV Voltage (kV)	Failure Consequence	Normal Degradation	NDI Data Quality	Abnormal Condition Code	Abnormal Thermal Code	Abnormal Electrical Code	Abnormal Core Code	Abnormal Index Data Quality	Oil Quality	Result Valid Until
Lauzon TS	STEPDN	1185117	1972	CW*	215.5	0.48	0.16	Good	1	1	1	1	Good	0.9	8/4/2016
Kenilworth TS	STEPDN	1189284	1960	CW*	110	0.28	0.16	Good	1	1	1	1	Good	0	2/3/2016
Bruce A TS	AUTO	1174352	1974	CGE*	500	1	0.16	Good	1	1	1	1	Good	0	6/24/2016
Leslie TS	STEPDN	1368377	2012	HYUNDAI*	215.5	0.53	0.16	Good	1	1	1	1	Good	0	4/19/2016
Otonabee TS	STEPDN	1174395	1989	ABB	215.5	0.53	0.16	Good	1	1	1	1	Good	0.31	2/17/2016
Cumberland TS	STEPDN	1252671	2010	HYUNDAI*	215.5	0.53	0.16	Good	1	1	1	1	Good	0	10/14/2016
Longwood TS	AUTO	1176849	1990	PEEB*	500	1	0.16	Good	1	1	1	1	Good	0	11/7/2016
Carlton TS	STEPDN	1180625	2005	HYUNDAI*	110	0.29	0.16	Marginal	1	1	1	1	Good	0	4/21/2016
Allanburg TS	AUTO	1173560	1972	CW*	236.8	0.78	0.16	Good	1	1	1	1	Good	0.12	5/25/2016
Leaside TS	AUTO	1181002	1982	ASEA	236.8	0.78	0.16	Good	1	1	1	1	Good	0	1/28/2016
Overbrook TS	STEPDN	1188297	1971	FP*	110	0.29	0.16	Good	1	1	1	1	Good	0	3/22/2016
Carling TS	STEPDN	1175089	1993	ABB	110	0.33	0.16	Good	1	1	1	1	Good	0.47	3/9/2016
Bracebridge TS	STEPDN	1176239	1972	CGE*	215.5	0.48	0.16	Good	1	1	1	1	Good	0	1/11/2016
Charles TS	STEPDN	1183475	1990	PION*	110	0.33	0.16	Good	1	1	1	1	Good	0	2/22/2016
Armitage TS	STEPDN	1173181	1990	PION*	215.5	0.53	0.16	Good	1	1	1	1	Good	0.11	7/15/2016
Agincourt TS	STEPDN	1188620	1979	CW*	215.5	0.53	0.15	Good	5	2	5	3	Good	0	4/11/2016
Belleville TS	STEPDN	1179668	1975	CW*	215.5	0.53	0.15	Good	5	2	5	2	Good	0.09	10/5/2016
Birch TS	STEPDN	1185400	1969	CW*	112	0.25	0.15	Good	5	1	5	2	Good	0	9/7/2016
Wingham TS	STEPDN	1191419	1965	EE*	235	0.51	0.15	Good	4	2	4	2	Good	0	5/4/2016
Nebo TS	STEPDN	1186835	1970	CW*	225	0.49	0.15	Good	2	2	2	2	Good	0.45	2/9/2016
Hinchey TS	STEPDN	2979691	2013	HYUNDAI*	110	0.29	0.15	Good	2	2	2	2	Good	0	6/29/2016
Buttonville TS	STEPDN	1188683	1979	CW*	215.5	0.53	0.15	Good	1	1	1	1	Good	0	10/5/2016
Everett TS	STEPDN	1174646	2007	SIEM*	215.5	0.48	0.15	Marginal	1	1	1	1	Good	0	1/12/2016
Armitage TS	STEPDN	1175709	1990	PION*	215.5	0.53	0.15	Good	1	1	1	1	Good	0.9	7/15/2016
Oakville TS #2	STEPDN	1252672	2010	HYUNDAI*	215.5	0.53	0.15	Good	1	1	1	1	Good	0	2/12/2016
Cherrywood TS	STEPDN	1173213	1979	CGE*	215.5	0.53	0.15	Good	1	1	1	1	Good	0.11	5/9/2016
Basin TS	STEPDN	1172970	1981	CW*	110	0.29	0.15	Good	1	1	1	1	Good	0.9	4/26/2016
Crawford TS	STEPDN	1171883	1960	CGE*	110	0.3	0.15	Good	1	1	1	1	Good	0.14	9/16/2016
Murray TS	STEPDN	1177897	1977	FP*	110	0.29	0.15	Good	1	1	1	1	Good	0	9/15/2016
Longwood TS	AUTO	1176862	1990	ABB	500	1	0.15	Good	1	1	1	1	Good	0.04	8/16/2016
Cherrywood TS	STEPDN	1186187	1980	CGE*	215.5	0.53	0.15	Good	1	1	1	1	Good	0	5/9/2016
Cecil TS	STEPDN	1191083	1993	ABB	110	0.33	0.15	Good	1	1	1	1	Good	0	3/31/2016
Buchanan TS	AUTO	1180779	1974	CGE*	236.8	0.78	0.15	Good	1	1	1	1	Good	0.34	8/10/2016
Tomken TS	STEPDN	1183921	1970	PION*	215.5	0.53	0.14	Good	5	2	5	3	Good	0.48	7/20/2016
Albion TS	STEPDN	1180419	1970	CW*	225	0.49	0.14	Good	5	2	5	3	Good	0	3/8/2016
Pleasant TS	STEPDN	1178799	1989	TTI*	215.5	0.53	0.14	Good	5	1	5	1	Good	0.18	11/22/2016
Douglas Point TS	STEPDN	1176890	1972	CGE*	215.5	0.48	0.14	Good	3	1	3	1	Good	0.63	7/29/2016
Alliston TS	STEPDN	1232225	1970	CGE*	215.5	0.48	0.14	Good	2	1	2	1	Good	0	4/14/2016
Minden TS	STEPDN	1188004	1956	ASEA	230	0.47	0.14	Good	1	1	1	1	Good	0.04	1/11/2016
Hinchey TS	STEPDN	2987735	2013	HYUNDAI*	110	0.29	0.14	Good	1	1	1	1	Good	0	5/3/2016
Churchill Meadows TS	STEPDN	1250900	2009	VONROLL*	215.5	0.53	0.14	Good	1	1	1	1	Good	0	7/13/2016
Chesterville TS	STEPDN	1368532	2009	VONROLL*	115.5	0.25	0.14	Good	1	1	1	1	Good	0	2/4/2016
Gerrard TS	STEPDN	1252077	2008	HYUNDAI*	110	0.33	0.14	Good	1	1	1	1	Good	0	3/29/2016
Gage TS	STEPDN	1187524	1942	CGE*	110	0.26	0.14	Good	1	1	1	1	Out of Date	0.66	4/15/2015
Kleinburg TS	STEPDN	1185249	1989	TTI*	215.5	0.53	0.14	Good	1	1	1	1	Good	0.11	5/18/2016
Longwood TS	AUTO	1174336	1990	ABB	500	1	0.14	Good	1	1	1	1	Good	0.13	8/18/2016
Owen Sound TS	STEPDN	1187283	1979	CGE*	215.5	0.53	0.14	Good	1	1	1	1	Good	0.14	10/17/2016
Kingsville TS	STEPDN	1182572	2001	PAUW*	115.5	0.25	0.14	Good	1	1	1	1	Good	0	7/14/2016
Wawa TS	AUTO	1181814	1969	EE*	226	0.55	0.14	Good	1	1	1	1	Good	0	6/20/2016
Pinard TS	AUTO	1191933	1993	ABB	500	1	0.14	Good	1	1	1	1	Good	0	10/19/2016
Brantford TS	STEPDN	2826439	2012	HYUNDAI*	215.5	0.53	0.14	Good	1	1	1	1	Good	0	1/11/2016
Birmingham TS	STEPDN	1176429	2003	HYUNDAI*	110	0.29	0.14	Good	1	1	1	1	Good	0	4/22/2016
Merivale TS	AUTO	1177686	1987	TTI*	236.8	0.78	0.14	Good	1	1	1	1	Good	0.7	3/15/2016
Burlington TS	AUTO	1248353	2007	ENERCO*	236.8	0.78	0.14	Marginal	1	1	1	1	Good	0.32	1/26/2016
Allanburg TS	STEPDN	3029813	2013	VONROLL*	110	0.24	0.14	Good	1	1	1	1	Good	0.47	4/13/2016
Richview TS	STEPDN	1188831	1991	ABB	215.5	0.53	0.14	Good	1	1	1	1	Good	0.03	11/10/2016
Malvern TS	STEPDN	1191268	1982	CW*	215.5	0.53	0.14	Good	1	1	1	1	Good	0	4/7/2016
Modeland TS	STEPDN	1175186	1991	ABB	215.5	0.53	0.14	Good	1	1	1	1	Good	0.05	2/3/2016
Oshawa G.M. TS	STEPDN	1179369	2005	PAUW*	232	0.58	0.14	Marginal	1	1	1	1	Good	0.45	2/25/2016
Detweiler TS	AUTO	1177840	1959	CGE*	236.8	0.78	0.14	Good	1	1	1	1	Good	0.04	6/20/2016
Tremaine TS	STEPDN	2742092	2010	HYUNDAI*	215.5	0.53	0.14	Good	1	1	1	1	Good	0	2/1/2016
Kenilworth TS	STEPDN	2742115	2011	ABB	110	0.33	0.14	Good	1	1	1	1	Good	0	3/11/2016
Malden TS	STEPDN	1252667	2010	HYUNDAI*	215.5	0.53	0.14	Good	1	1	1	1	Good	0	1/20/2016
Albion TS	STEPDN	1187870	1970	CW*	225	0.49	0.13	Good	5	3	5	4	Good	0.89	3/16/2016
Caledonia TS	STEPDN	1184251	1972	CW*	215.5	0.48	0.13	Good	4	2	4	2	Good	0	2/11/2016
Glengrove TS	STEPDN	1250742	2009	PAUW*	115.5	0.25	0.13	Good	1	1	1	1	Good	0	6/1/2016
Dunnville TS	STEPDN	3077938	2013	VONROLL*	110	0.24	0.13	Good	1	1	1	1	Good	0	6/6/2016
Dunnville TS	STEPDN	3077553	2013	VONROLL*	110	0.24	0.13	Good	1	1	1	1	Good	0	6/6/2016
Frontenac TS	STEPDN	1192168	1977	CW*	216	0.48	0.13	Good	1	1	1	1	Good	0	2/25/2016
Pleasant TS	STEPDN	1176021	1975	CW*	215.5	0.53	0.13	Good	1	1	1	1	Good	0.19	2/1/2016

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Ansonville TS	AUTO	1174175	1991	PION*	226	0.55	0.13	Good	1	1	1	1	Good	0.16	8/24/2016
Richview TS	STEPDN	1175868	1991	ABB	215.5	0.53	0.13	Good	1	1	1	1	Good	0	11/10/2016
Otto Holden TS	AUTO	1178111	1953	CW*	230	0.46	0.13	Good	1	1	1	1	Good	0.05	4/20/2016
Edgeware TS	STEPDN	1179531	1982	CGE*	215.5	0.53	0.13	Good	1	1	1	1	Good	0	7/18/2016
N-TS-STLAWRENTS-TF-R33	TF: Reg - 300MVA 230-230-12.7kV	1179815	1958	CW*	230	0.88	0.13	Good	1	1	1	1	Out of Date	0	2/19/2015
Bruce A TS	AUTO	1189603	1976	CGE*	500	1	0.13	Good	1	1	1	1	Out of Date	0	11/13/2014
Dryden TS	STEPDN	1185286	1948	CGE*	110	0.22	0.13	Good	1	1	1	1	Good	0.49	4/6/2016
Brantford TS	STEPDN	1367726	2010	HYUNDAI*	215.5	0.53	0.13	Good	1	1	1	1	Good	0	1/11/2016
Centralia TS	STEPDN	1188352	1951	CGE*	110	0.23	0.13	Good	1	1	1	1	Good	0	4/26/2016
Carlton TS	STEPDN	1180635	2005	HYUNDAI*	110	0.29	0.13	Good	1	1	1	1	Good	0	7/12/2016
Vansickle TS	STEPDN	1251532	2004	HYUNDAI*	110	0.29	0.13	Good	1	1	1	1	Good	0	11/23/2016
Buchanan TS	STEPDN	1191019	1991	ABB	215.5	0.53	0.13	Good	1	1	1	1	Good	0	2/25/2016
Halton TS	STEPDN	1177507	1989	ABB	215.5	0.53	0.13	Good	1	1	1	1	Good	0.17	4/15/2016
Carling TS	STEPDN	1190473	1993	ABB	110	0.33	0.13	Good	1	1	1	1	Good	0	3/9/2016
Elmira TS	STEPDN	3019495	2013	VONROLL*	110	0.24	0.13	Good	1	1	1	1	Good	0	6/27/2016
Galt TS	STEPDN	1251796	2009	HYUNDAI*	215.5	0.53	0.13	Good	1	1	1	1	Good	0.21	6/24/2016
Muskoka TS	STEPDN	1186692	1980	CGE*	215.5	0.53	0.13	Good	1	1	1	1	Good	0.03	10/31/2016
Oshawa G.M. TS	STEPDN	1187121	2005	PAUW*	232	0.58	0.13	Marginal	1	1	1	1	Good	0	2/25/2016
Talbot TS	STEPDN	1191443	1979	CW*	215.5	0.53	0.12	Good	5	2	5	3	Good	0	6/7/2016
Lisgar TS	STEPDN	1306389	2008	HYUNDAI*	110	0.29	0.12	Good	4	2	4	3	Good	0.18	9/16/2016
Fergus TS	STEPDN	1190697	1972	PION*	215.5	0.53	0.12	Good	4	2	4	2	Good	0	6/24/2016
Wilson TS	STEPDN	1188773	1975	ASEA	215.5	0.53	0.12	Good	4	2	4	2	Good	0	2/17/2016
Clarke TS	STEPDN	1185898	1969	CW*	220	0.49	0.12	Good	3	2	3	2	Good	0	2/20/2016
Alliston TS	STEPDN	1186639	1972	CGE*	215.5	0.48	0.12	Good	1	1	1	1	Good	0.84	10/4/2016
Whitby TS	STEPDN	1173334	1991	PION*	215.5	0.53	0.12	Good	1	1	1	1	Good	0	3/24/2016
Lake TS	STEPDN	1173930	1971	CW*	216	0.48	0.12	Good	1	1	1	1	Good	0	2/25/2016
Pinard TS	AUTO	1174159	2006	HYUNDAI*	500	1	0.12	Marginal	1	1	1	1	Out of Date	0	7/27/2015
Malden TS	STEPDN	1368369	2010	HYUNDAI*	215.5	0.53	0.12	Good	1	1	1	1	Good	0	1/20/2016
Arnprior TS	STEPDN	1177668	1960	ASEA	110	0.24	0.12	Good	1	1	1	1	Good	0.17	3/30/2016
Merivale TS	AUTO	1185479	1977	CGE*	236.8	0.78	0.12	Good	1	1	1	1	Good	0.7	3/15/2016
Holland TS	STEPDN	1247124	2007	ENERCO*	215.5	0.53	0.12	Marginal	1	1	1	1	Good	0.72	2/1/2016
Burlington TS	AUTO	1173785	1977	CGE*	236.8	0.78	0.12	Good	1	1	1	1	Good	0	7/28/2016
Cherrywood TS	AUTO	1178587	1990	ABB	500	1	0.12	Good	1	1	1	1	Good	0.03	11/4/2016
Almonte TS	STEPDN	2981764	2013	VONROLL*	215.5	0.48	0.12	Good	1	1	1	1	Out of Date	0	3/16/2015
Riverdale TS	STEPDN	1177698	1988	PION*	110	0.29	0.12	Good	1	1	1	1	Good	0	3/23/2016
Longueuil TS	STEPDN	1179752	1965	CGE*	235	0.52	0.12	Good	1	1	1	1	Good	0	2/5/2016
Claireville TS	AUTO	3008897	2012	HYUNDAI*	500	1	0.12	Good	1	1	1	1	Good	0	12/6/2016
Claireville TS	AUTO	1190194	1990	PEEB*	500	1	0.12	Good	1	1	1	1	Good	0.45	9/22/2016
Belle River TS	STEPDN	1183059	2005	PAUW*	115.5	0.25	0.12	Marginal	1	1	1	1	Good	0.07	2/9/2016
Trafalgar TS	AUTO	3026291	2014	HYUNDAI*	500	1	0.12	Good	1	1	1	1	Good	0	7/4/2016
Bridgman TS	STEPDN	3064852	2014	VONROLL*	110	0.33	0.12	Good	1	1	1	1	Good	0	11/16/2016
Midhurst TS	STEPDN	1181373	1975	CW*	215.5	0.53	0.12	Good	1	1	1	1	Out of Date	0	3/14/2015
Alliston TS	STEPDN	1232213	1970	CGE*	215.5	0.48	0.12	Good	1	1	1	1	Good	0	9/15/2016
Thornton TS	STEPDN	2981763	2013	VONROLL*	215.5	0.53	0.12	Good	1	1	1	1	Good	0	11/24/2016
Terauley TS	STEPDN	1191165	1976	FP*	110	0.38	0.12	Good	1	1	1	1	Good	0	3/8/2016
Gage TS	STEPDN	1177155	1965	FP*	110	0.37	0.12	Good	1	1	1	1	Good	0.08	1/11/2016
Dymond TS	STEPDN	3039499	2014	CGPOWER*	115.5	0.25	0.12	Good	1	1	1	1	Good	0	6/1/2016
Keith TS	STEPDN	1306390	2010	HYUNDAI*	215.5	0.48	0.12	Good	1	1	1	1	Good	0	1/19/2016
Modeland TS	STEPDN	1368372	2010	HYUNDAI*	215.5	0.53	0.12	Good	1	1	1	1	Good	0	2/3/2016
Cardiff TS	STEPDN	1186420	2004	HYUNDAI*	215.5	0.48	0.12	Good	1	1	1	1	Good	0.54	4/4/2016
Beach TS	STEPDN	1189237	1976	CW*	215.5	0.47	0.11	Good	5	2	5	3	Out of Date	0.84	9/28/2015
Birch TS	STEPDN	1185384	1969	CW*	112	0.25	0.11	Good	5	2	5	3	Good	0	9/7/2016
Richview TS	STEPDN	1183846	1969	CW*	220	0.54	0.11	Good	4	2	4	2	Good	0	11/10/2016
Crowland TS	STEPDN	1176321	1968	FP*	225.5	0.5	0.11	Good	2	2	1	1	Good	0.38	10/14/2016
Nebo TS	STEPDN	2817468	2012	HYUNDAI*	215.5	0.53	0.11	Good	1	1	1	1	Good	0.55	4/19/2016
Leaside TS	AUTO	1191148	1989	PION*	236.8	0.78	0.11	Good	1	1	1	1	Good	0.29	1/29/2016
Napanee TS	STEPDN	1184881	1974	CW*	216	0.48	0.11	Good	1	1	1	1	Good	0	9/20/2016
Highbury TS	STEPDN	1182007	1991	FP*	110	0.3	0.11	Good	1	1	1	1	Good	0.04	5/13/2016
Talbot TS	STEPDN	1173493	2007	HYUNDAI*	215.5	0.48	0.11	Marginal	1	1	1	1	Good	0	6/7/2016
Port Arthur TS #1	STEPDN	1190424	1974	CW*	115	0.25	0.11	Good	1	1	1	1	Good	0.57	8/15/2016
Buchanan TS	AUTO	1178184	1968	CGE*	236.8	0.78	0.11	Good	1	1	1	1	Good	0	8/10/2016
Stayner TS	STEPDN	1248007	2008	ENERCO*	215.5	0.53	0.11	Good	1	1	1	1	Good	0	1/14/2016
Ingersoll TS	STEPDN	1945134	2010	HYUNDAI*	215.5	0.53	0.11	Good	1	1	1	1	Good	0	5/30/2016
Cooksville TS	STEPDN	3031109	2013	HYUNDAI*	215.5	0.48	0.11	Good	1	1	1	1	Good	0	2/10/2016
Gerrard TS	STEPDN	3142918	2014	HYUNDAI*	110	0.33	0.11	Good	1	1	1	1	Good	0	12/12/2016
Pleasant TS	STEPDN	1240231	2008	HYUNDAI*	215.5	0.53	0.11	Good	1	1	1	1	Good	0	9/20/2016
Cardiff TS	STEPDN	1183898	2004	HYUNDAI*	215.5	0.48	0.11	Good	1	1	1	1	Good	0	6/27/2016
John TS	STEPDN	1175660	1975	FP*	110	0.29	0.11	Good	1	1	1	1	Good	0	9/19/2016
Kent TS	STEPDN	1180026	1974	PION*	215.5	0.53	0.11	Good	1	1	1	1	Good	0	1/21/2016
Elmira TS	STEPDN	3026285	2013	VONROLL*	110	0.24	0.11	Good	1	1	1	1	Out of Date	0.7	12/8/2014

Station	Designation	SAP Equipment Number	Vintage	Manufacturer	HV Voltage (kV)	Failure Consequence	Normal Degradation	NDI Data Quality	Abnormal Condition Code	Abnormal Thermal Code	Abnormal Electrical Code	Abnormal Core Code	Abnormal Index Data Quality	Oil Quality	Result Valid Until
Manby TS	AUTO	1183423	1986	CGE*	236.8	0.78	0.11	Good	1	1	1	1	Good	0	2/2/2016
Cooksville TS	STEPDN	3031110	2013	HYUNDAI*	215.5	0.48	0.11	Good	1	1	1	1	Good	0	5/6/2016
Wawa TS	AUTO	1187020	1969	EE*	226	0.55	0.11	Good	1	1	1	1	Out of Date	0	9/21/2015
Sarnia Scott TS	AUTO	1178080	1980	CGE*	236.8	0.78	0.11	Good	1	1	1	1	Good	0.24	5/10/2016
Richview TS	STEPDN	1368370	2010	HYUNDAI*	215.5	0.48	0.11	Good	1	1	1	1	Good	0	12/6/2016
Port Hope TS	STEPDN	1176930	1988	PION*	110	0.3	0.11	Good	1	1	1	1	Good	0	2/9/2016
Douglas Point TS	STEPDN	1184775	1970	CGE*	215.5	0.48	0.11	Good	1	1	1	1	Good	0.9	12/21/2016
Richview TS	STEPDN	1368371	2010	HYUNDAI*	215.5	0.48	0.11	Good	1	1	1	1	Good	0	12/12/2016
Whitby TS	STEPDN	1186310	2006	HYUNDAI*	215.5	0.53	0.11	Marginal	1	1	1	1	Good	0	3/24/2016
Jarvis TS	STEPDN	1190779	1972	CW*	215.5	0.48	0.1	Good	4	2	4	2	Good	0.64	4/18/2016
Martindale TS	STEPDN	1181718	1970	PION*	215.5	0.53	0.1	Good	2	1	2	2	Good	0	10/12/2016
Kenilworth TS	STEPDN	1186885	1965	FP*	110	0.37	0.1	Good	3	3	1	1	Good	0	5/26/2016
Brant TS	STEPDN	1306268	2003	PAUW*	110	0.3	0.1	Marginal	1	1	1	1	Good	0	12/28/2016
Owen Sound TS	AUTO	1176877	1974	CGE*	236.8	0.78	0.1	Good	1	1	1	1	Good	0.48	4/6/2016
Red Lake TS	STEPDN	1182845	2007	SIEM*	115.5	0.25	0.1	Marginal	1	1	1	1	Good	0.09	5/3/2016
Bronte TS	STEPDN	1188929	2005	VATECH*	110	0.3	0.1	Good	1	1	1	1	Good	0	6/16/2016
Hanmer TS	AUTO	3099992	2014	HYUNDAI*	500	1	0.1	Good	1	1	1	1	Good	0	4/28/2016
Meaford TS	STEPDN	3036593	2013	CGPOWER*	115.5	0.25	0.1	Good	1	1	1	1	Good	0	10/24/2016
Nelson TS	STEPDN	1189511	2003	HYUNDAI*	110	0.29	0.1	Marginal	1	1	1	1	Good	0.8	9/21/2016
Bramalea TS	STEPDN	1177442	2004	HYUNDAI*	215.5	0.53	0.1	Marginal	1	1	1	1	Good	0	2/26/2016
Scarboro TS	STEPDN	1175764	1992	PION*	215.5	0.53	0.1	Good	1	1	1	1	Good	0	4/6/2016
Goreway TS	STEPDN	1251733	2009	HYUNDAI*	215.5	0.53	0.1	Good	1	1	1	1	Good	0	9/27/2016
Campbell TS	STEPDN	1183010	1990	PION*	215.5	0.47	0.1	Good	1	1	1	1	Good	0	7/15/2016
Marathon TS	AUTO	1185346	1976	CGE*	226	0.55	0.1	Good	1	1	1	1	Good	0	4/27/2016
Main TS	STEPDN	1178467	1973	FP*	110	0.29	0.1	Good	1	1	1	1	Good	0	4/29/2016
Port Hope TS	STEPDN	1179654	1988	PION*	110	0.3	0.1	Good	1	1	1	1	Good	0	10/4/2016
Wallaceburg TS	STEPDN	2815257	2013	VONROLL*	110	0.24	0.1	Good	1	1	1	1	Out of Date	0	1/6/2015
Sidney TS	STEPDN	1177036	1991	ABB	110	0.3	0.1	Good	1	1	1	1	Good	0.22	8/25/2016
Chesterville TS	STEPDN	2701517	2012	CGPOWER*	115.5	0.25	0.1	Good	1	1	1	1	Good	0	2/4/2016
King Edward TS	STEPDN	1180455	1993	ABB	110	0.33	0.1	Good	1	1	1	1	Good	0.05	3/11/2016
Detweiler TS	AUTO	1175297	2004	PAUW*	236.8	0.78	0.1	Good	1	1	1	1	Good	0.12	6/20/2016
Pembroke TS	STEPDN	2977653	2013	CGPOWER*	115.5	0.25	0.1	Good	1	1	1	1	Good	0	4/20/2016
Burlington TS	AUTO	1189139	1990	ABB	236.8	0.78	0.1	Marginal	1	1	1	1	Good	0	1/14/2016
Morrisburg TS	STEPDN	1189775	1988	PION*	110	0.3	0.1	Good	1	1	1	1	Good	0	2/8/2016
Sheppard TS	STEPDN	1173306	1991	ABB	215.5	0.53	0.1	Good	1	1	1	1	Good	0	4/5/2016
Lincoln Heights TS	STEPDN	1187945	1974	CW*	110	0.29	0.1	Good	1	1	1	1	Good	0	5/6/2016
Sheppard TS	STEPDN	1175801	1991	ABB	215.5	0.53	0.1	Good	1	1	1	1	Good	0	4/5/2016
Hearst TS	STEPDN	1186778	2003	PAUW*	115.5	0.25	0.1	Good	1	1	1	1	Out of Date	0.03	7/21/2015
Dryden TS	STEPDN	1185268	1948	CGE*	110	0.22	0.1	Good	1	1	1	1	Good	0.49	4/6/2016
Beach TS	AUTO	1173907	1973	CGE*	236.8	0.78	0.1	Good	1	1	1	1	Out of Date	0.18	6/29/2015
Caledonia TS	AUTO	1184238	2003	VATECH*	236.8	0.57	0.1	Good	1	1	1	1	Good	0	2/11/2016
Nepean TS	STEPDN	1183323	1978	CW*	215.5	0.53	0.09	Good	5	2	5	3	Good	0.76	9/13/2016
Beach TS	STEPDN	1173860	1976	CW*	215.5	0.47	0.09	Good	4	2	4	2	Out of Date	0.06	8/31/2015
Sidney TS	STEPDN	1174477	1991	ABB	110	0.3	0.09	Good	4	2	4	2	Good	0	6/17/2016
Wonderland TS	STEPDN	1184622	1966	CGE*	220	0.5	0.09	Good	4	2	4	2	Good	0.48	1/28/2016
Thornton TS	STEPDN	3055438	2014	VONROLL*	215.5	0.53	0.09	Good	1	1	1	1	Good	0	10/11/2016
Leaside TS	STEPDN	2376712	2010	CGPOWER*	225.75	0.5	0.09	Good	1	1	1	1	Good	0	6/7/2016
Pembroke TS	STEPDN	2826676	2013	CGPOWER*	115.5	0.25	0.09	Good	1	1	1	1	Good	0	4/20/2016
Highbury TS	STEPDN	1251263	2009	ELCO*	110	0.3	0.09	Good	1	1	1	1	Good	0	5/13/2016
Lambton TS #2	AUTO	1180109	1973	CGE*	346	1	0.09	Good	1	1	1	1	Good	0.9	1/11/2016
Tremaine TS	STEPDN	2742091	2010	HYUNDAI*	215.5	0.53	0.09	Good	1	1	1	1	Good	0	2/1/2016
Churchill Meadows TS	STEPDN	1250901	2009	VONROLL*	215.5	0.53	0.09	Good	1	1	1	1	Good	0	11/7/2016
Lisgar TS	STEPDN	1190530	1973	FP*	110	0.29	0.09	Good	1	1	1	1	Good	0	3/21/2016
Cedar TS	AUTO	3100410	2014	HYUNDAI*	239	0.79	0.09	Good	1	1	1	1	Good	0	7/12/2016
Hawthorne TS	AUTO	1190504	1989	TTI*	500	1	0.09	Good	1	1	1	1	Good	0	10/13/2016
Horning TS	STEPDN	1184393	1967	FP*	220	0.51	0.09	Good	1	1	1	1	Good	0.9	11/3/2016
Talbot TS	STEPDN	1191431	2007	HYUNDAI*	215.5	0.48	0.09	Marginal	1	1	1	1	Good	0	6/7/2016
Ellesmere TS	STEPDN	1367976	2010	HYUNDAI*	215.5	0.53	0.09	Good	1	1	1	1	Good	0	4/7/2016
Leaside TS	STEPDN	2376699	2010	CGPOWER*	225.75	0.5	0.09	Good	1	1	1	1	Good	0.24	11/25/2016
Cobden TS	STEPDN	3036329	2014	CGPOWER*	115.5	0.25	0.09	Good	1	1	1	1	Good	0	11/28/2016
Tillsonburg TS	STEPDN	1189581	2004	ELCO*	110	0.3	0.09	Good	1	1	1	1	Good	0.15	10/6/2016
Nebo TS	STEPDN	1173848	1970	CW*	225	0.49	0.09	Good	1	1	1	1	Good	0.82	5/25/2016
Smiths Falls TS	STEPDN	1188022	1991	PION*	215.5	0.53	0.09	Good	1	1	1	1	Good	0.81	7/8/2016
Orleans TS	STEPDN	3055133	2014	HYUNDAI*	215.5	0.53	0.09	Good	1	1	1	1	Good	0	6/9/2016
Manby TS	STEPDN	1183402	2006	HYUNDAI*	215.5	0.44	0.09	Marginal	1	1	1	1	Good	0.04	6/2/2016
Whitby TS	STEPDN	1183829	2006	HYUNDAI*	215.5	0.53	0.09	Marginal	1	1	1	1	Good	0.9	3/24/2016
Lennox TS	AUTO	1192283	1974	CW*	500	1	0.09	Good	1	1	1	1	Good	0.07	6/7/2016
Duart TS	STEPDN	1368533	2010	HYUNDAI*	215.5	0.53	0.09	Good	1	1	1	1	Good	0	1/26/2016
Lauzon TS	STEPDN	1172038	1969	CW*	220	0.49	0.08	Good	4	2	4	3	Good	0	4/14/2016
Dobbin TS	STEPDN	1179639	1971	PION*	215.5	0.53	0.08	Good	5	2	5	2	Good	0	2/3/2016

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Fairchild TS	STEPDN	1186381	1979	CW*	215.5	0.53	0.08	Good	2	2	2	2	Out of Date	0	9/20/2015
Orillia TS	STEPDN	1184115	1975	CW*	215.5	0.53	0.08	Good	2	1	2	1	Good	0.9	1/15/2016
Nanticoke TS	AUTO	1190807	1974	CGE*	500	1	0.08	Good	1	1	1	1	Good	0	3/14/2016
Erindale TS	STEPDN	1185197	1988	PION*	215.5	0.53	0.08	Good	1	1	1	1	Good	0.23	4/11/2016
Red Lake TS	STEPDN	1182858	2007	SIEM*	115.5	0.25	0.08	Marginal	1	1	1	1	Good	0	5/3/2016
Russell TS	STEPDN	1190547	1975	FP*	110	0.29	0.08	Good	1	1	1	1	Good	0.06	3/24/2016
Hearst TS	STEPDN	1173751	1974	CW*	115	0.25	0.08	Good	1	1	1	1	Good	0	3/23/2016
Preston TS	AUTO	1174843	2007	PAUW*	239	0.79	0.08	Marginal	1	1	1	1	Good	0	5/10/2016
Crosby TS	STEPDN	1189874	1990	ABB	215.5	0.44	0.08	Good	1	1	1	1	Good	0	4/21/2016
Erindale TS	STEPDN	1187730	1989	PION*	215.5	0.53	0.08	Good	1	1	1	1	Good	0.1	4/7/2016
Campbell TS	STEPDN	1190709	1990	PION*	215.5	0.47	0.08	Good	1	1	1	1	Good	0	7/15/2016
Hawthorne TS	AUTO	1190516	1990	PEEB*	500	1	0.08	Good	1	1	1	1	Good	0.03	11/8/2016
Belle River TS	STEPDN	1185625	2005	PAUW*	115.5	0.25	0.08	Marginal	1	1	1	1	Good	0	8/2/2016
Lauzon TS	AUTO	1172055	1968	CGE*	236.8	0.78	0.08	Good	1	1	1	1	Good	0.6	11/10/2016
Cobden TS	STEPDN	2736773	2012	CGPOWER*	115.5	0.25	0.08	Good	1	1	1	1	Good	0	9/2/2016
Bunting TS	STEPDN	1185689	1996	PAUW*	110	0.29	0.08	Good	1	1	1	1	Good	0	6/22/2016
Longlac TS	STEPDN	1254070	2009	VONROLL*	115.5	0.25	0.08	Good	1	1	1	1	Good	0.25	5/5/2016
Terauley TS	STEPDN	1178505	1976	FP*	110	0.38	0.08	Good	1	1	1	1	Good	0	3/3/2016
Strachan TS	STEPDN	1186120	1972	FP*	110	0.29	0.08	Good	1	1	1	1	Good	0	2/18/2016
Bermondsey TS	STEPDN	1186216	1990	PION*	215.5	0.53	0.08	Good	1	1	1	1	Good	0	3/10/2016
Manby TS	STEPDN	1191058	2005	HYUNDAI*	215.5	0.44	0.08	Good	1	1	1	1	Good	0.04	6/9/2016
N-TS-STLAWRENTS-TF-PS33	TF: PShift - 300MVA 240-240kV	1179801	1962	CGE*	240	0.89	0.08	Good	1	1	1	1	Out of Date	0	2/19/2015
Cedar TS	STEPDN	1180554	1992	ABB	110	0.29	0.08	Good	1	1	1	1	Good	0.1	6/24/2016
Stratford TS	STEPDN	1174309	1969	HAWK*	220	0.49	0.08	Good	1	1	1	1	Good	0.12	6/24/2016
Parkway TS	AUTO	1177237	2004	VATECH*	500	1	0.08	Good	1	1	1	1	Good	0.43	10/13/2016
Manby TS	STEPDN	1185913	2004	HYUNDAI*	215.5	0.44	0.08	Good	1	1	1	1	Good	0.02	2/2/2016
Stayner TS	AUTO	1248020	2008	ENERCO*	239	0.57	0.08	Good	1	1	1	1	Good	0	1/14/2016
Leaside TS	AUTO	1178425	1992	PION*	236.8	0.78	0.08	Good	1	1	1	1	Good	0.63	1/29/2016
Napanee TS	STEPDN	1187390	1974	CW*	216	0.48	0.08	Good	1	1	1	1	Good	0.12	9/20/2016
St.Lawrence TS	STEPDN	1184892	1991	PION*	215.5	0.53	0.08	Good	1	1	1	1	Good	0	2/24/2016
King Edward TS	STEPDN	1172404	1972	FP*	110	0.29	0.08	Good	1	1	1	1	Good	0	11/18/2016
Agincourt TS	STEPDN	1191210	1979	CW*	215.5	0.53	0.08	Good	1	1	1	1	Good	0	4/11/2016
Glengrove TS	STEPDN	1175649	2003	PROLEC*	115.5	0.25	0.08	Good	1	1	1	1	Good	0.11	12/19/2016
Lakehead TS	AUTO	3033682	2013	HYUNDAI*	239	0.79	0.08	Good	1	1	1	1	Good	0	11/30/2016
Larchwood TS	STEPDN	3101326	2015	VONROLL*	115.5	0.25	0.08	Good	1	1	1	1	Good	0	11/8/2016
Edgeware TS	STEPDN	1176814	1982	CGE*	215.5	0.53	0.08	Good	1	1	1	1	Good	0	7/18/2016
Jarvis TS	STEPDN	1177864	1972	CW*	215.5	0.48	0.07	Good	4	2	4	3	Good	0	2/5/2016
Dobbin TS	STEPDN	1192155	1971	PION*	215.5	0.53	0.07	Good	2	2	2	1	Good	0	2/3/2016
Brockville TS	STEPDN	1184818	1975	CW*	215.5	0.53	0.07	Good	1	1	1	1	Good	0	2/1/2016
Goreway TS	STEPDN	1251739	2009	HYUNDAI*	215.5	0.53	0.07	Good	1	1	1	1	Good	0	9/27/2016
Hanover TS	AUTO	1249855	2005	VATECH*	236.8	0.57	0.07	Marginal	1	1	1	1	Good	0.9	3/18/2016
N-TS-PARKWAYTS -TF-T3	TF: Auto - 750MVA 500-240-28kV	1177256	2004	VATECH*	500	1	0.07	Marginal	1	1	1	1	Out of Date	0	9/10/2015
Dundas TS	STEPDN	3035167	2015	ABB	110	0.3	0.07	Good	1	1	1	1	Good	0	8/10/2016
Stayner TS	STEPDN	1248006	2008	ENERCO*	215.5	0.53	0.07	Good	1	1	1	1	Good	0	10/11/2016
Longwood TS	STEPDN	1182202	1992	FP*	215.5	0.48	0.07	Good	1	1	1	1	Good	0.9	8/20/2016
Allanburg TS	STEPDN	3039874	2013	VONROLL*	110	0.24	0.07	Good	1	1	1	1	Good	0	4/13/2016
Allanburg TS	AUTO	1186592	1969	CGE*	236.8	0.78	0.07	Good	1	1	1	1	Good	0	4/13/2016
Fort William TS	STEPDN	1182771	1975	CW*	115	0.31	0.07	Good	1	1	1	1	Good	0	6/29/2016
Morrisburg TS	STEPDN	1189787	1988	PION*	110	0.3	0.07	Good	1	1	1	1	Good	0	2/8/2016
Meadowvale TS	STEPDN	1181204	1991	PION*	215.5	0.53	0.07	Good	1	1	1	1	Good	0.21	10/11/2016
Midhurst TS	STEPDN	1186653	1988	TTI*	215.5	0.53	0.07	Good	1	1	1	1	Good	0	4/1/2016
Des Joachims TS	AUTO	1183252	1969	CGE*	236.8	0.57	0.07	Good	1	1	1	1	Good	0.63	5/10/2016
Goderich TS	STEPDN	1178206	2006	AREVA*	115.5	0.24	0.07	Good	1	1	1	1	Good	0.04	8/22/2016
Gardiner TS	STEPDN	1240237	2008	SIEM*	215.5	0.48	0.07	Good	1	1	1	1	Good	0.22	4/6/2016
Tomken TS	STEPDN	1186508	1990	PION*	215.5	0.53	0.07	Good	1	1	1	1	Out of Date	0	8/22/2015
Toyota Woodstock TS	STEPDN	1188886	2003	SIEM*	115.5	0.25	0.07	Marginal	1	1	1	1	Good	0.5	4/8/2016
Nelson TS	STEPDN	1184596	1974	PION*	110	0.29	0.07	Good	1	1	1	1	Good	0	3/7/2016
Essa TS	AUTO	1173615	1972	PARS*	500	1	0.07	Good	1	1	1	1	Out of Date	0.06	3/5/2015
Woodstock TS	STEPDN	3037102	2014	ABB	110	0.3	0.07	Good	1	1	1	1	Good	0	3/4/2016
Tillsonburg TS	STEPDN	1187194	2004	ELCO*	110	0.3	0.07	Good	1	1	1	1	Good	0.22	4/19/2016
Gage TS	STEPDN	1179959	1965	FP*	110	0.37	0.07	Good	1	1	1	1	Good	0	1/19/2016
St.Isidore TS	STEPDN	1176999	1968	FP*	220	0.46	0.06	Good	3	2	3	2	Good	0	2/25/2016
Wallaceburg TS	STEPDN	2376698	2011	VONROLL*	110	0.24	0.06	Good	3	2	3	2	Good	0	2/4/2016
St.Marys TS	STEPDN	1187143	2003	PROLEC*	115.5	0.25	0.06	Good	1	1	1	1	Good	0	4/26/2016
Bunting TS	STEPDN	1188137	1975	FP*	110	0.29	0.06	Good	1	1	1	1	Good	0	4/4/2016
Picton TS	STEPDN	1192235	1960	CGE*	230	0.5	0.06	Good	1	1	1	1	Good	0.9	8/4/2016
Kent TS	STEPDN	1182455	1999	PAUW*	215.5	0.44	0.06	Good	1	1	1	1	Good	0	1/22/2016
Marathon TS	AUTO	1175001	1976	CGE*	226	0.55	0.06	Good	1	1	1	1	Good	0	4/7/2016
Carlaw TS	STEPDN	1185944	1975	FP*	110	0.29	0.06	Good	1	1	1	1	Good	0.13	4/14/2016
Almonte TS	STEPDN	3064854	2014	VONROLL*	215.5	0.48	0.06	Good	1	1	1	1	Good	0	12/19/2016

Station	Designation	SAP Equipment Number	Vintage	Manufacturer	HV Voltage (kV)	Failure Consequence	Normal Degradation	NDI Data Quality	Abnormal Condition Code	Abnormal Thermal Code	Abnormal Electrical Code	Abnormal Core Code	Abnormal Index Data Quality	Oil Quality	Result Valid Until
Dymond TS	STEPDN	3081096	2015	CGPOWER*	115.5	0.25	0.06	Good	1	1	1	1	Good	0	11/22/2016
Cherrywood TS	AUTO	1173201	2000	ABB	500	1	0.06	Good	1	1	1	1	Good	0	7/15/2016
Wiltshire TS	STEPDN	3093722	2015	VONROLL*	110	0.33	0.06	Good	1	1	1	1	Good	0	11/4/2016
St.Lawrence TS	STEPDN	1174454	1992	PION*	215.5	0.53	0.06	Good	1	1	1	1	Good	0.2	8/19/2016
Hawthorne TS	AUTO	1190488	1989	TTI*	500	1	0.06	Good	1	1	1	1	Good	0	10/12/2016
Bermondsey TS	STEPDN	1178625	1990	PION*	215.5	0.53	0.06	Good	1	1	1	1	Good	0	3/10/2016
Woodstock TS	STEPDN	3020568	2013	ABB	110	0.3	0.06	Good	1	1	1	1	Good	0	3/4/2016
Dundas TS	STEPDN	3008371	2014	ABB	110	0.3	0.06	Good	1	1	1	1	Good	0	10/7/2016
Holland TS	STEPDN	1247123	2007	ENERCO*	215.5	0.53	0.06	Marginal	1	1	1	1	Good	0.08	2/1/2016
Goreway TS	STEPDN	3064853	2014	VONROLL*	215.5	0.48	0.06	Good	1	1	1	1	Good	0	10/7/2016
Kirkland Lake TS	SVC	2740399	2010	ABB	115	0.25	0.06	Good	1	1	1	1	Good	0	4/19/2016
Kirkland Lake TS	STEPDN	3066130	2014	CGPOWER*	115.5	0.25	0.06	Good	1	1	1	1	Good	0	11/24/2016
Duart TS	STEPDN	1306391	2010	HYUNDAI*	215.5	0.53	0.06	Good	1	1	1	1	Good	0	2/22/2016
Stanley TS	STEPDN	1172647	1989	PION*	110	0.29	0.06	Good	1	1	1	1	Good	0.45	7/27/2016
Longwood TS	AUTO	1184725	1990	ABB	500	1	0.06	Good	1	1	1	1	Good	0	11/7/2016
Detweiler TS	SVC	2740763	2010	ABB	230	0.55	0.06	Good	1	1	1	1	Out of Date	0	7/23/2015
Meadowvale TS	STEPDN	1181221	1990	PION*	215.5	0.53	0.06	Good	1	1	1	1	Good	0	2/22/2016
Ingersoll TS	STEPDN	2701726	2012	HYUNDAI*	215.5	0.53	0.06	Good	1	1	1	1	Good	0	5/30/2016
Cooksville TS	STEPDN	3035119	2013	HYUNDAI*	215.5	0.48	0.06	Good	1	1	1	1	Good	0	2/10/2016
Duplex TS	STEPDN	1173039	1974	PION*	110	0.29	0.06	Good	1	1	1	1	Good	0.19	12/10/2016
Gardiner TS	STEPDN	1240236	2008	SIEM*	215.5	0.48	0.06	Good	1	1	1	1	Good	0	3/3/2016
Manby TS	AUTO	1183438	1981	CW*	236.8	0.78	0.06	Good	1	1	1	1	Good	0	5/19/2016
St.Lawrence TS	AUTO	1177014	1992	ABB	239	0.79	0.06	Good	1	1	1	1	Good	0.72	10/23/2016
Pleasant TS	STEPDN	1186457	1975	CW*	215.5	0.53	0.05	Good	5	2	5	3	Good	0.18	3/3/2016
Whitby TS	STEPDN	1191326	1991	ABB	215.5	0.53	0.05	Good	2	1	2	2	Good	0	3/24/2016
Des Joachims TS	AUTO	3066323	2013	VONROLL*	239	0.57	0.05	Good	5	1	5	1	Good	0.61	6/6/2016
Leslie TS	STEPDN	1186277	1998	ABB	210	0.52	0.05	Good	1	1	1	1	Good	0	4/27/2016
Trout Lake TS	STEPDN	1179286	1972	PION*	215.5	0.53	0.05	Good	1	1	1	1	Good	0	4/27/2016
Hawthorne TS	AUTO	1187905	2008	ENERCO*	236.8	0.78	0.05	Good	1	1	1	1	Good	0.59	6/6/2016
Caledonia TS	AUTO	1173800	2003	VATECH*	236.8	0.57	0.05	Good	1	1	1	1	Good	0	2/11/2016
Cecil TS	STEPDN	1180878	2003	PAUW*	110	0.33	0.05	Good	1	1	1	1	Good	0	10/4/2016
Essa TS	AUTO	1233734	1972	PARS*	500	1	0.05	Marginal	1	1	1	1	Out of Date	0.9	8/5/2015
Commerce Way TS	STEPDN	2736510	2010	HYUNDAI*	110	0.3	0.05	Good	1	1	1	1	Good	0	5/26/2016
Tomken TS	STEPDN	1173467	1990	PION*	215.5	0.53	0.05	Good	1	1	1	1	Good	0	5/4/2016
Orangeville TS	STEPDN	1177407	1969	EE*	220	0.49	0.05	Good	1	1	1	1	Good	0.57	2/18/2016
Wiltshire TS	STEPDN	1178530	2003	PROLEC*	115.5	0.25	0.05	Good	1	1	1	1	Good	0	2/29/2016
Beck #2 TS	AUTO	1185676	1983	CGE*	345	1	0.05	Good	1	1	1	1	Good	0	10/28/2016
Hanover TS	AUTO	3041580	2013	VONROLL*	239	0.57	0.05	Good	1	1	1	1	Good	0	6/21/2016
Crosby TS	STEPDN	1251218	2009	VONROLL*	215.5	0.48	0.05	Good	1	1	1	1	Good	0.84	7/8/2016
Essa TS	AUTO	1176187	1992	PION*	226	0.55	0.05	Good	1	1	1	1	Good	0	3/23/2016
Commerce Way TS	STEPDN	2736509	2010	HYUNDAI*	110	0.3	0.05	Good	1	1	1	1	Good	0	2/20/2016
Brockville TS	STEPDN	1189674	1975	CW*	215.5	0.53	0.05	Good	1	1	1	1	Good	0	2/1/2016
Longwood TS	STEPDN	1189593	1992	FP*	215.5	0.48	0.05	Good	1	1	1	1	Good	0	8/20/2016
Malvern TS	STEPDN	1181114	1982	CGE*	215.5	0.53	0.05	Good	1	1	1	1	Good	0	4/7/2016
Horning TS	STEPDN	1189258	1967	FP*	220	0.51	0.05	Good	1	1	1	1	Out of Date	0.44	2/15/2014
Kapuskasing TS	STEPDN	1181657	1978	PION*	215.5	0.48	0.05	Good	1	1	1	1	Good	0.55	3/1/2016
Lincoln Heights TS	STEPDN	1185509	1975	FP*	110	0.29	0.05	Good	1	1	1	1	Good	0	5/6/2016
Everett TS	STEPDN	1177222	2007	SIEM*	215.5	0.48	0.05	Marginal	1	1	1	1	Good	0.19	3/7/2016
Crosby TS	STEPDN	1179825	1990	ABB	215.5	0.44	0.05	Good	1	1	1	1	Good	0	5/31/2016
Bridgman TS	STEPDN	1180851	1972	FP*	110	0.29	0.05	Good	1	1	1	1	Good	0	11/7/2016
Leslie TS	STEPDN	1173293	1963	CW*	210	0.52	0.05	Good	1	1	1	1	Good	0	5/27/2016
Ear Falls TS	STEPDN	1190448	1967	CW*	138	0.28	0.05	Good	1	1	1	1	Good	0.09	5/2/2016
Martindale TS	AUTO	3063222	2013	VONROLL*	239	0.57	0.05	Good	1	1	1	1	Good	0	4/29/2016
Porcupine TS	AUTO	1189465	1967	CW*	480	1	0.04	Marginal	5	2	5	3	Good	0.04	10/23/2016
St.Isidore TS	STEPDN	1192257	1968	FP*	220	0.46	0.04	Good	3	2	3	2	Good	0	2/10/2016
Smiths Falls TS	STEPDN	1185569	1991	PION*	215.5	0.53	0.04	Good	4	4	4	1	Good	0.84	6/3/2016
Norfolk TS	STEPDN	1177916	2003	FP*	110	0.3	0.04	Good	1	1	1	1	Good	0	2/4/2016
Birch TS	STEPDN	3081006	2015	CGPOWER*	112	0.25	0.04	Good	1	1	1	1	Good	0	9/7/2016
Meaford TS	STEPDN	3036330	2013	CGPOWER*	115.5	0.25	0.04	Good	1	1	1	1	Good	0	10/24/2016
Goreway TS	STEPDN	1177495	1992	PION*	215.5	0.53	0.04	Good	1	1	1	1	Good	0	9/14/2016
St.Lawrence TS	AUTO	1189858	1992	ABB	239	0.79	0.04	Good	1	1	1	1	Good	0.9	2/24/2016
Karn TS	AUTO	1937443	2010	CGPOWER*	239	0.79	0.04	Good	1	1	1	1	Good	0	5/9/2016
Detweiler TS	SVC	2740706	2010	ABB	230	0.55	0.04	Good	1	1	1	1	Good	0	7/6/2016
Dryden TS	AUTO	1172271	1976	CGE*	226	0.55	0.04	Good	1	1	1	1	Good	0.9	4/6/2016
Porcupine TS	AUTO	1181927	1967	CGE*	472.74	1	0.04	Good	1	1	1	1	Good	0	6/15/2016
Clarabelle TS	STEPDN	1191803	1972	PION*	215.5	0.53	0.04	Good	1	1	1	1	Good	0	5/19/2016
Picton TS	STEPDN	1192245	1960	CGE*	230	0.5	0.04	Good	1	1	1	1	Good	0	6/8/2016
Winona TS	STEPDN	1179897	2003	VATECH*	110	0.3	0.04	Good	1	1	1	1	Good	0.02	2/4/2016
Winona TS	STEPDN	1187485	2003	VATECH*	110	0.3	0.04	Good	1	1	1	1	Good	0	2/4/2016
Stewartville TS	STEPDN	3066370	2014	CGPOWER*	115.5	0.25	0.04	Good	1	1	1	1	Good	0	11/14/2016

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Dryden TS	AUTO	1182701	1977	CGE*	226	0.55	0.04	Good	1	1	1	1	Good	0	4/6/2016
Orleans TS	STEPDN	3055080	2014	ABB	110	0.3	0.04	Good	1	1	1	1	Good	0	9/26/2016
Fort William TS	STEPDN	1185297	1974	CW*	115	0.31	0.04	Good	1	1	1	1	Good	0.04	6/29/2016
Crystal Falls TS	STEPDN	1191886	1969	CW*	220	0.45	0.04	Good	1	1	1	1	Good	0	4/12/2016
Manitoulin TS	STEPDN	1252566	2004	VATECH*	115.5	0.25	0.04	Marginal	1	1	1	1	Good	0	6/1/2016
Goderich TS	STEPDN	2736506	2011	ABB	110	0.3	0.04	Good	1	1	1	1	Good	0	8/22/2016
Trafalgar TS	STEPDN	1191398	1998	ABB	215.5	0.48	0.04	Good	1	1	1	1	Good	0.14	11/10/2016
Palermo TS	STEPDN	1186580	1969	HAWK*	220	0.49	0.04	Good	1	1	1	1	Good	0.14	9/23/2016
Port Arthur TS #1	STEPDN	1177639	1974	CW*	115	0.25	0.04	Good	1	1	1	1	Good	0	8/15/2016
Manby TS	STEPDN	1188402	2003	PAUW*	215.5	0.44	0.04	Good	1	1	1	1	Good	0.04	2/2/2016
Manitoulin TS	STEPDN	2769271	2013	CGPOWER*	115.5	0.25	0.04	Good	1	1	1	1	Good	0	6/1/2016
Seaforth TS	STEPDN	1176730	1959	CGE*	110	0.24	0.04	Good	1	1	1	1	Good	0	3/11/2016
Nanticoke TS	SVC	2383402	2010	SIEM*	500	1	0.03	Good	3	2	3	2	Out of Date	0	4/17/2015
Seaforth TS	STEPDN	1176744	1959	CGE*	110	0.24	0.03	Good	1	1	1	1	Good	0	3/11/2016
Pleasant TS	STEPDN	1240230	2008	HYUNDAI*	215.5	0.53	0.03	Good	1	1	1	1	Good	0	5/11/2016
Hawthorne TS	AUTO	1175104	2004	PAUW*	236.8	0.78	0.03	Good	1	1	1	1	Good	0	5/2/2016
Orangeville TS	STEPDN	1180200	1969	EE*	220	0.49	0.03	Good	1	1	1	1	Good	0.9	2/18/2016
Espanola TS	STEPDN	1184224	2015	CGPOWER*	115.5	0.25	0.03	Good	1	1	1	1	Out of Date	0.25	4/7/2015
Kapuskasing TS	STEPDN	1179215	1978	PION*	215.5	0.48	0.03	Good	1	1	1	1	Good	0	2/23/2016
Cooksville TS	STEPDN	3061653	2013	HYUNDAI*	215.5	0.48	0.03	Good	1	1	1	1	Good	0	2/10/2016
Lennox TS	AUTO	1182335	2001	SMIT*	500	1	0.03	Good	1	1	1	1	Good	0.11	8/12/2016
Trafalgar TS	STEPDN	1191409	1998	ABB	215.5	0.48	0.03	Good	1	1	1	1	Good	0.35	10/14/2016
St.Marys TS	STEPDN	1174285	2003	PROLEC*	115.5	0.25	0.03	Good	1	1	1	1	Good	0	4/26/2016
Nanticoke TS	AUTO	1175349	1974	CW*	500	1	0.03	Good	1	1	1	1	Good	0	4/5/2016
Norfolk TS	STEPDN	1183114	2003	FP*	110	0.3	0.03	Good	1	1	1	1	Good	0	2/4/2016
Bramalea TS	STEPDN	1187690	1988	PION*	215.5	0.53	0.03	Good	1	1	1	1	Good	0	2/26/2016
Wiltshire TS	STEPDN	1178517	2003	VATECH*	115.5	0.25	0.03	Good	1	1	1	1	Good	0.04	2/29/2016
Beck #2 TS	AUTO	1190836	1983	CGE*	345	1	0.03	Good	1	1	1	1	Good	0.06	7/25/2016
Wallace TS	STEPDN	1179396	1969	CW*	220	0.45	0.02	Good	5	2	5	3	Good	0	4/19/2016
Caledonia TS	STEPDN	1179060	1972	CW*	215.5	0.48	0.02	Good	5	2	5	2	Good	0	2/11/2016
Lindsay TS	STEPDN	1188807	1979	CW*	215.5	0.53	0.02	Good	3	1	3	2	Good	0.49	2/2/2016
Timmins TS	STEPDN	1179272	1971	CW*	216	0.48	0.02	Good	2	2	2	2	Out of Date	0.5	5/4/2015
N-TS-LAMBTON2TS-TF-PS4	TF: PShift - 845MVA 240-240kV	1185085	1999	ABB	240	1	0.02	Marginal	2	1	2	1	Out of Date	0.53	1/21/2015
Trout Lake TS	STEPDN	1189436	1972	PION*	215.5	0.53	0.02	Good	2	1	2	1	Good	0	4/27/2016
Walker TS #1	STEPDN	1171949	1971	CW*	216	0.48	0.02	Good	2	1	2	1	Good	0	1/22/2016
Dufferin TS	STEPDN	1180892	2015	VONROLL*	110	0.33	0.02	Good	2	2	1	1	Good	0	6/27/2016
Beaverton TS	STEPDN	1183657	1990	PION*	215.5	0.53	0.02	Good	1	1	1	1	Good	0.3	12/16/2016
N-TS-STLAWRENTS-TF-PSR34	TF: PHSR - 300MVA 240-240kV	1187413	1978	CGE*	240	0.89	0.02	Good	1	1	1	1	Out of Date	0	2/20/2015
Seaforth TS	AUTO	1174255	1958	CGE*	236.8	0.78	0.02	Good	1	1	1	1	Good	0	4/12/2016
Nanticoke TS	SVC	2383403	2010	SIEM*	500	1	0.02	Good	1	1	1	1	Out of Date	0	4/17/2015
Dymond TS	AUTO	1191540	1976	CGE*	226	0.55	0.02	Good	1	1	1	1	Good	0	6/1/2016
Barwick TS	STEPDN	2736507	2013	CGPOWER*	115.5	0.25	0.02	Good	1	1	1	1	Good	0	4/20/2016
Palermo TS	STEPDN	1181306	1969	HAWK*	220	0.49	0.02	Good	1	1	1	1	Good	0.33	6/13/2016
Beaverton TS	STEPDN	1191223	1990	PION*	215.5	0.53	0.02	Good	1	1	1	1	Out of Date	0	2/10/2015
Strathroy TS	STEPDN	1182161	2015	VONROLL*	110	0.24	0.02	Good	1	1	1	1	Good	0.22	10/27/2016
Wiltshire TS	STEPDN	3137640	2015	VONROLL*	110	0.33	0.02	Good	1	1	1	1	Good	0	12/8/2016
Beamsville TS	STEPDN	1245962	2003	ELCO*	115.5	0.25	0.02	Good	1	1	1	1	Good	0	5/13/2016
N-TS-BIRCHTS -TF-T3	TF: Stepdn - 41.7MVA 110-28KV	1247078	2008	ENERCO*	110	0.24	0.02	Good	1	1	1	1	Out of Date	0	2/24/2015
Kent TS	STEPDN	1254098	2005	VATECH*	215.5	0.44	0.02	Marginal	1	1	1	1	Good	0	11/16/2016
Elliot Lake TS	STEPDN	1232172	1996	PAUW*	110	0.24	0.02	Good	1	1	1	1	Good	0	8/12/2016
Glengrove TS	STEPDN	1180974	2004	PROLEC*	115.5	0.25	0.02	Good	1	1	1	1	Good	0	4/15/2016
Cedar TS	AUTO	3100409	2014	HYUNDAI*	239	0.79	0.02	Good	1	1	1	1	Good	0	7/12/2016
Nanticoke TS	SVC	2383401	2010	SIEM*	500	1	0.02	Good	1	1	1	1	Good	0	11/21/2016
Longlac TS	STEPDN	1254069	2009	VONROLL*	115.5	0.25	0.02	Good	1	1	1	1	Good	0	5/5/2016
Espanola TS	STEPDN	1189068	2015	CGPOWER*	115.5	0.25	0.02	Good	1	1	1	1	Good	0	2/9/2016
Dundas TS #2	STEPDN	1179887	2003	VATECH*	110	0.3	0.02	Good	1	1	1	1	Good	0.04	2/3/2016
Barwick TS	STEPDN	3020946	2013	CGPOWER*	115.5	0.25	0.02	Good	1	1	1	1	Good	0	10/26/2016
Goreway TS	STEPDN	1187753	1992	PION*	215.5	0.53	0.02	Good	1	1	1	1	Good	0.78	9/27/2016
Stewartville TS	STEPDN	1180694	2015	CGPOWER*	115.5	0.25	0.02	Good	1	1	1	1	Good	0.28	3/16/2016
Midhurst TS	STEPDN	1184062	1993	PION*	215.5	0.53	0.02	Good	1	1	1	1	Good	0	3/3/2016
Midhurst TS	STEPDN	1191487	1993	TTI*	215.5	0.53	0.01	Good	2	2	1	1	Good	0.86	3/23/2016
Brown Hill TS	STEPDN	1191234	1992	PION*	215.5	0.53	0.01	Good	1	1	1	1	Good	0	4/4/2016
Porcupine TS	AUTO	1179307	1967	CGE*	472.74	1	0.01	Good	1	1	1	1	Good	0	6/23/2016
Porcupine TS	SVC	1368726	2010	CGPOWER*	230	0.52	0.01	Good	1	1	1	1	Good	0	1/20/2016
Beamsville TS	STEPDN	1245986	2003	ELCO*	115.5	0.25	0.01	Marginal	1	1	1	1	Good	0.21	4/20/2016
Allanburg TS	AUTO	1176135	2016	HYUNDAI*	239	0.79	0.01	Good	1	1	1	1	Out of Date	0	5/19/2015
Bramalea TS	STEPDN	1172141	1988	PION*	215.5	0.53	0.01	Good	1	1	1	1	Good	0	2/26/2016
Manitouwadge TS	STEPDN	3035220	2013	CGPOWER*	115.5	0.25	0.01	Good	1	1	1	1	Good	0	11/14/2016
Timmins TS	STEPDN	3111766	2014	ABB	110	0.3	0.01	Good	1	1	1	1	Good	0.89	10/17/2016
Birmingham TS	STEPDN	1176450	1973	FP*	110	0.29	0.01	Good	1	1	1	1	Good	0	9/22/2016

Station	Designation	SAP Equipment Number	Vintage	Manufacturer	HV Voltage (kV)	Failure Consequence	Normal Degradation	NDI Data Quality	Abnormal Condition Code	Abnormal Thermal Code	Abnormal Electrical Code	Abnormal Core Code	Abnormal Index Data Quality	Oil Quality	Result Valid Until
Brant TS	STEPDN	1172081	2015	VONROLL*	110	0.3	0.01	Good	1	1	1	1	Good	0.3	1/6/2016
Crystal Falls TS	STEPDN	1187035	1969	CW*	220	0.45	0.01	Good	1	1	1	1	Good	0	7/26/2016
Brown Hill TS	STEPDN	1188670	1992	PION*	215.5	0.53	0.01	Good	1	1	1	1	Good	0	3/8/2016
Lakehead TS	AUTO	1172300	2013	HYUNDAI*	239	0.79	0.01	Good	1	1	1	1	Good	0	11/3/2016
John TS	STEPDN	1183550	1977	PION*	110	0.38	0.01	Good	1	1	1	1	Good	0	2/25/2016
Ramore TS	STEPDN	1186973	2002	FP*	115.5	0.23	0.01	Good	1	1	1	1	Good	0	11/22/2016
Porcupine TS	SVC	1368727	2010	CGPOWER*	230	0.52	0.01	Good	1	1	1	1	Out of Date	0	7/8/2015
Karn TS	AUTO	1377762	2010	CGPOWER*	239	0.79	0.01	Good	1	1	1	1	Good	0	5/9/2016
Dundas TS #2	STEPDN	1187469	2003	VATECH*	110	0.3	0.01	Good	1	1	1	1	Good	0.02	2/3/2016
Wallace TS	STEPDN	1191982	1968	FP*	220	0.46	0	Good	4	2	4	2	Good	0	4/19/2016
Wilson TS	STEPDN	1173245	1975	ASEA	215.5	0.53	0	Good	3	2	3	2	Good	0	2/17/2016
Lindsay TS	STEPDN	1186299	1979	CW*	215.5	0.53	0	Good	2	1	2	2	Good	0	2/2/2016
Bruce HW Plant B TS	STEPDN	1173482	1975	CW*	225	0.51	0	Good	1	1	1	1	Good	0	10/5/2016
Dymond TS	AUTO	1189034	1976	CGE*	226	0.55	0	Good	1	1	1	1	Good	0.05	6/1/2016
Crowland TS	STEPDN	1181502	1968	FP*	225.5	0.5	0	Good	1	1	1	1	Good	0	4/5/2016
Cherrywood TS	AUTO	1245867	2008	ABB	500	1	0	Good	1	1	1	1	Good	0	6/15/2016
N-TS-KEITHTS -TF-PSR5	TF: PHSR - 500MVA 230-230kV	1180074	1975	CGE*	230	1	0	Good	1	1	1	1	Out of Date	0	1/30/2015
Goderich TS	STEPDN	3081094	2015	VONROLL*	110	0.3	0	Good	1	1	1	1	Good	0	12/21/2016
Bruce HW Plant B TS	STEPDN	1181278	1975	CW*	225	0.51	0	Good	1	1	1	1	Good	0	7/29/2016
Spruce Falls TS	AUTO	1184539	1977	CGE*	226	0.55	0	Good	1	1	1	1	Good	0.7	2/24/2016
N-TS-LAMBTON2TS-TF-PS51	TF: PShift - 845MVA 240-240kV	1185098	1999	ABB	240	1	0	Good	1	1	1	1	Out of Date	0	1/21/2015
Essa TS	AUTO	1191909	1972	CW*	500	1	0	Marginal	1	1	1	1	Marginal	0	12/13/2016
Essex TS	STEPDN	1249407	2007	HYUNDAI*	110	0.3	0	Marginal	1	1	1	1	Good	0	4/19/2016
Essex TS	STEPDN	1249409	2007	HYUNDAI*	110	0.3	0	Marginal	1	1	1	1	Good	0	4/19/2016
Orillia TS	STEPDN	1368118	2010	VONROLL*	215.5	0.53	0	Good	1	1	1	1	Good	0	3/1/2016
Porcupine TS	SVC	1368728	2010	CGPOWER*	230	0.52	0	Good	1	1	1	1	Out of Date	0	7/8/2015
Detweiler TS	SVC	2740792	2010	ABB	230	0.55	0	Good	1	1	1	1	Out of Date	0	7/23/2015
Kirkland Lake TS	STEPDN	3066131	1950	CGE*	110	0.24	0	Marginal	1	1	1	1	Marginal	0.89	12/15/2016

Station	Designation	SAP Equipment Number	Vintage	Manufacturer	HV Voltage (kV)	Failure Consequence	Normal Degradation	NDI Data Quality	Abnormal Condition Code	Abnormal Thermal	Abnormal Electrical	Abnormal Core	Abnormal Index Data Quality	Oil Quality	Result Valid Until
N-TS-NANTICOKTS-TF-T13	(R) TF: Stepdn - 116MVA 500-26.5KV	2383401	2010	SIEMENS*	500	1	0.01	Good	1	0	0	0	Good	0	11/21/2016
N-TS-KARNTS -TF-T2	TF: Auto 150/200/250 MVA 239/121/13.8 kV	1377762	2010	CG POWER*	239	0.61	0.01	Good	1	0	0	0	Good	0	5/9/2016
N-TS-BRAMALEATS-TF-T6	TF: Stepdn - 125MVA 215.5-44kV	1172141	1988	PIONEER*	215.5	0.47	0.01	Good	1	0	0	0	Good	0	2/26/2016
N-TS-BROWNHILTS-TF-T2	TF: Stepdn - 125MVA 215.5-44kV	1188670	1992	PIONEER*	215.5	0.47	0.01	Good	1	0	0	0	Good	0	3/8/2016
N-TS-JOHNTS -TF-T6	TF: Stepdn - 125MVA 110-14.2-14.2kV	1183550	1977	PION*	110	0.24	0.01	Good	1	0	0	0	Good	0	2/25/2016
N-TS-RAMORETS -TF-T1	TF: Stepdn - 16.7MVA 115.5-27.1kV	1186973	2002	FP*	115.5	0.23	0.01	Good	1	0	0	0	Good	0	11/22/2016
N-TS-PORCUPINTS-TF-T1	(W) TF: Stepdn - 60/80/100 MVA	1368727	2010	CG POWER*	230	0.48	0.01	Good	1	0	0	0	Out of Date	0	7/8/2015
N-TS-BROWNHILTS-TF-T1	TF: Stepdn - 125MVA 215.5-44kV	1191234	1992	PIONEER*	215.5	0.47	0.01	Good	1	0	0	0	Good	0	4/4/2016
N-TS-PORCUPINTS-TF-T1	(R) TF: Stepdn - 60/80/100 MVA	1368726	2010	CG POWER*	230	0.48	0.01	Good	1	0	0	0	Good	0	1/20/2016
N-TS-BARWICKTS -TF-T1	TF: Stepdn - 41.67MVA 110-44-4kV	3020946	2012	CG POWER*	110	0.23	0.01	Good	1	0	0	0	Good	0	10/26/2016
N-TS-SPRUCFLSTS-TF-T7	TF: Auto - 125MVA 226-125/116-14.1kV	1184539	1977	CGE*	226	0.55	0	Good	1	0	0	0	Good	0.7	2/24/2016
N-TS-DYMONDTS -TF-T1	TF: Auto - 125MVA 226-125/116-14.1kV	1189034	1976	CGE*	226	0.55	0	Good	1	0	0	0	Good	0.05	6/1/2016
N-TS-DUNDAS2TS -TF-T6	TF: Stepdn - 83.3MVA 110-28.4kV	1187469	2003	VATECH*	110	0.25	0	Good	1	0	0	0	Good	0.02	2/3/2016
N-TS-WALLACETS -TF-T4	TF: Stepdn - 41.67MVA 220-44kV	1191982	1968	FERRANTI*	220	0.44	0	Good	4	0.41	0.6	0.47	Good	0	4/19/2016
N-TS-WILSONTS -TF-T3	TF: Stepdn - 125MVA 215.5-44-13kV	1173245	1975	ASEA	215.5	0.47	0	Good	3	0.3	0.59	0.38	Good	0	2/17/2016
N-TS-LINDSAYTS -TF-T2	TF: Stepdn - 125MVA 215.5-44kV	1186299	1979	WESTINGHOUSE*	215.5	0.47	0	Good	2	0.26	0.36	0.31	Good	0	2/2/2016
N-TS-BRUCEHWBTS-TF-T7	TF: Stepdn - 100MVA 225-14-14kV	1181278	1975	CW*	225	0.46	0	Good	1	0.12	0.18	0.15	Good	0	7/29/2016
N-TS-KEITHTS -TF-PSR5	TF: PHSR - 500MVA 230-230kV	1180074	1975	CGE*	230	0.88	0	Good	1	0.08	0.16	0	Out of Date	0	1/30/2015
N-TS-CROWLANDTS-TF-T5	TF: Stepdn - 83.3MVA 112.75-28kV	1181502	1968	FERRANTI*	112.75	0.26	0	Good	1	0.1	0	0	Good	0	4/5/2016
N-TS-BARWICKTS -TF-T2	TF: Stepdn - 41.7MVA 115-44KV	2736507	2013	CG POWER*	110	0.33	0	Good	1	0	0	0	Good	0	4/20/2016
N-TS-BRUCEHWBTS-TF-T8	TF: Stepdn - 100MVA 225-14-14kV	1173482	1975	CW*	225	0.46	0	Good	1	0	0	0	Good	0	10/5/2016
N-TS-CHERRYWDTS-TF-T16	TF: Auto - 750MVA 500-240-28kV	1245867	2006	ABB	500	1	0	Good	1	0	0	0	Good	0	6/15/2016
N-TS-LAMBTON2TS-TF-PS51	TF: PShift - 845MVA 240-240kV	1185098	1999	ABB	240	1	0	Good	1	0	0	0	Out of Date	0	1/21/2015
N-TS-ESSEXTS -TF-T5	TF: Stepdn - 83.3 MVA 110-28KV	1249407	2007	HYUNDAI*	110	0.25	0	Good	1	0	0	0	Good	0	4/19/2016
N-TS-ESSEXTS -TF-T6	TF: Stepdn - 83.3 MVA 110-28KV	1249409	2007	HYUNDAI*	110	0.25	0	Good	1	0	0	0	Good	0	4/19/2016
N-TS-PORCUPINTS-TF-T1	(B) TF: Stepdn - 60/80/100 MVA	1368728	2010	CG POWER*	230	0.48	0	Good	1	0	0	0	Out of Date	0	7/8/2015
N-TS-DETWEILRTS-TF-T1	(B) TF: Stepdn 116.7 MVA , 230 - 22.5 kV	2740792	2010	ABB	230	0.49	0	Good	1	0	0	0	Out of Date	0	7/23/2015

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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

ELECTRIC POWER RESEARCH INSTITUTE

Derivation of Transmission Substation Transformer Hazard Functions

Derivation of Transmission Substation Transformer Hazard Functions

Technical Update, February 2018

THE FOLLOWING ORGANIZATION(S), UNDER CONTRACT TO EPRI, PREPARED THIS REPORT:

EPRI

Coplanar Consulting, LLC

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The following organization(s), under contract to the Electric Power Research Institute (EPRI), prepared this report:

Electric Power Research Institute (EPRI)
1300 West W.T. Harris Blvd.
Charlotte, NC28262

Principal Investigator
B. Desai
J. Bolano

Coplanar Consulting, LLC
893 Princess Drive
Yardley, PA 19067

Principal Investigator
M. Lebow

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ABSTRACT

A key goal of asset management is to base decisions on an equipment fleet's mean life expectancy. Insights on the fleet mean life expectancy may be derived from careful analysis of historical replacement data. This report describes EPRI work to model and develop transformer removal hazard rates from historical replacement records and apply them to forecast the number of transformers expected to require replacement based on past replacement practices.

EPRI has developed a methodology using advanced statistical techniques for analyzing transformer historical replacements and applied it to the Hydro One Networks Inc. transmission substation transformer fleet. Hydro One Networks Inc. provided in-service, failure and removed from service data for their transformer fleet. Using this data, EPRI developed models for removal rates of transformers as a function of their age. The models along with information about the current fleet were used to project the number transformers expected to be removed from service over the next five year period assuming past practices are continued to be followed. The results are provided in transformer fleet groups (high side voltage in kV) as follows: 115, 230, and 500.

Keywords
Power Transformers
Asset Management
Industry-wide Database
Fleet Management

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SUPPLIED TRANSFORMER DATA

Data Received

Hydro One Networks Inc. (Hydro One) provided the following data as shown in Table 1-1. The transformer fleet has been grouped by high side voltage in kV and whether the unit is an auto or non-auto.

Table 1-1
Transformer Group Data

Group	In-service	Failures	Removed from Service
115 kV Non-Auto	276	19	297
230 kV Non-Auto	303	15	76
230 kV Auto	94	3	25
500 kV Auto	48	8	21
500 kV 250 MVA Auto Single Phase	12		8
500 kV 750 MVA Auto Three Phase	32		10

In-service Data

The in-service data provided by Hydro One consists of 721 transformers as of first quarter 2017. The data included the following fields:

- Substation
- Transformer Position
- Serial Number
- Manufacturer
- Auto Transformer (Yes/No)
- HV Winding Volts
- LV Winding Volts – 01
- LV Winding Volts – 02
- Tertiary Winding Volts

- Top MVA Rating
- Number of Phases
- Date Installed
- Age

Figure 1-1 shows the age demographics of the in-service transformer fleet as of first quarter 2017.

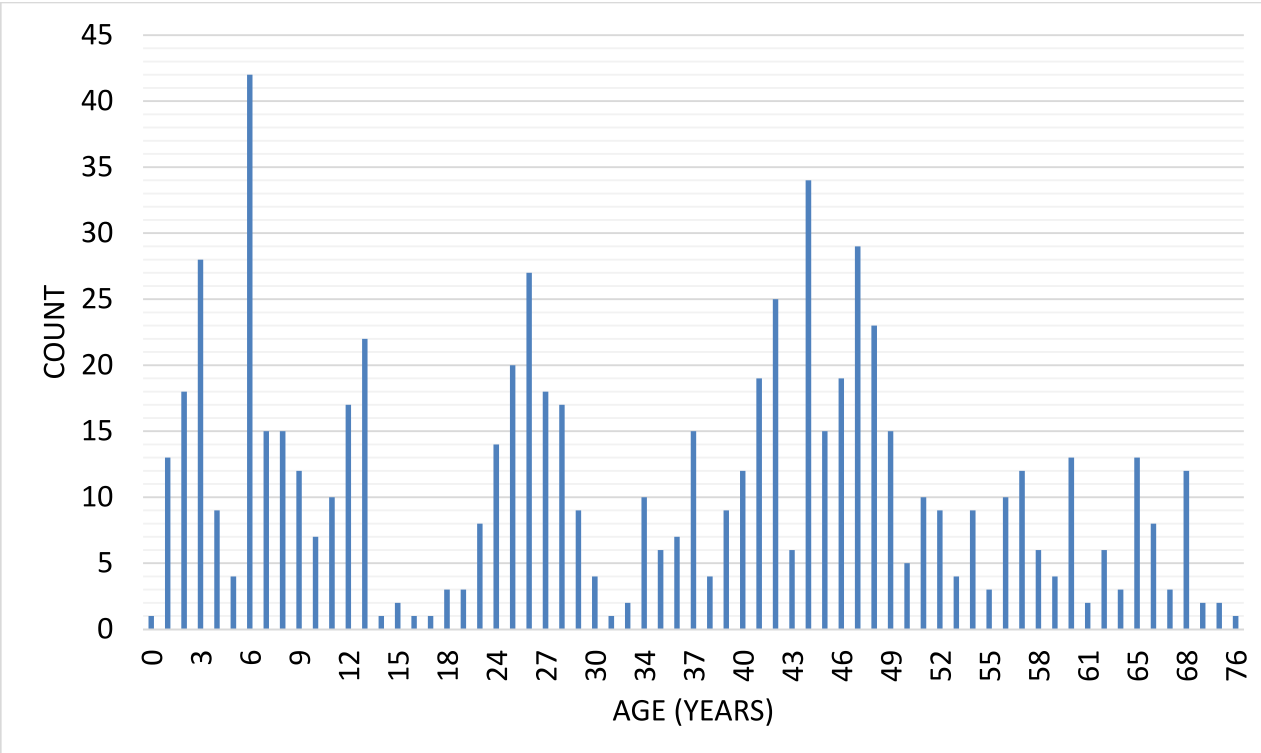

Figure 1-1
In-service Transformer Age Demographics

Removed from Service Data

The removed from service data provided by Hydro One consists of 419 transformers as of first quarter 2017. The data included the following fields:

- Substation
- Transformer Position
- Serial Number
- Manufacturer
- Auto Transformer (Yes/No)
- HV Winding Volts

- LV Winding Volts – 01
- LV Winding Volts – 02
- Tertiary Winding Volts
- Top MVA Rating
- Number of Phases
- Date Installed
- Date Removed
- Age

Figure 1-2 shows the age demographics of the removed from service transformers from the period of 1981 to first quarter 2017.

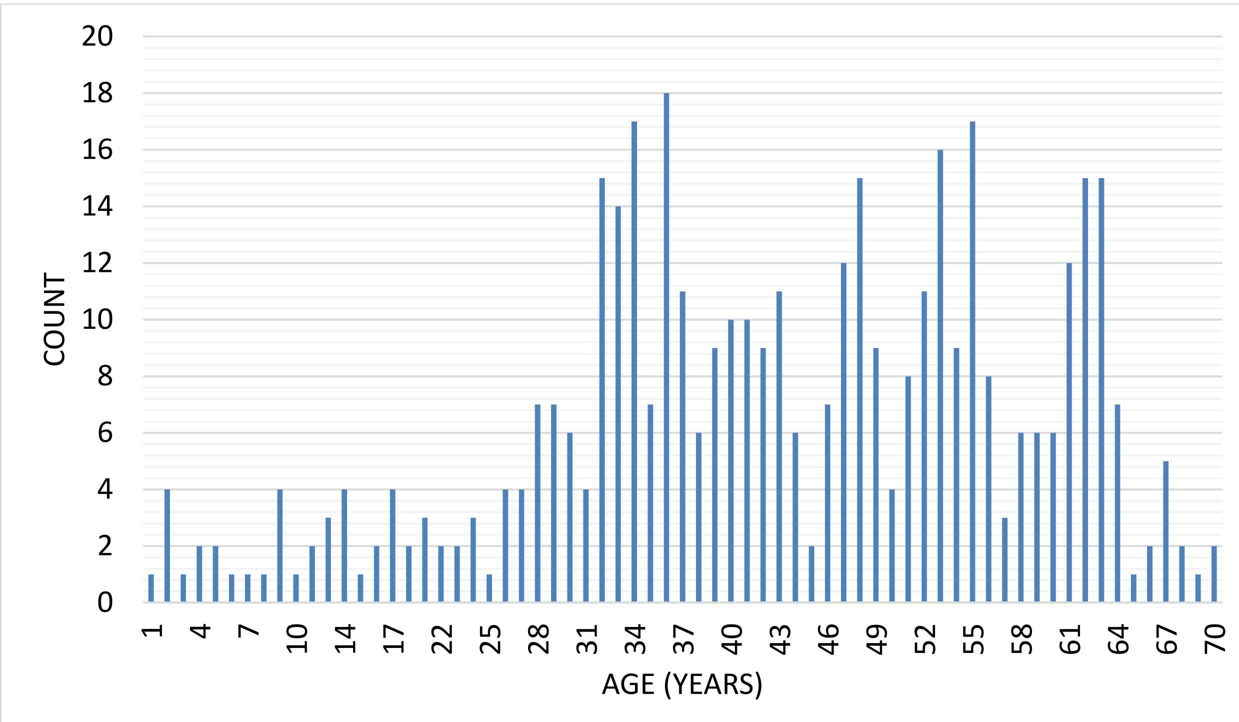

Figure 1-2
Removed from Service Transformer Age Demographics

Failure Data

The failure data provided by Hydro One consists of 42 transformers as of first quarter 2017. The data included the following fields:

- Substation
- Transformer Position

- Serial Number
- Manufacturer
- Auto Transformer (Yes/No)
- HV Winding Volts
- LV Winding Volts – 01
- LV Winding Volts – 02
- Tertiary Winding Volts
- Top MVA Rating
- Number of Phases
- Date Installed
- Date Failed
- Age
- Failed Component

Figure 1-3 shows the age demographics of the failed transformers from the period of 2006 to fourth quarter 2016.

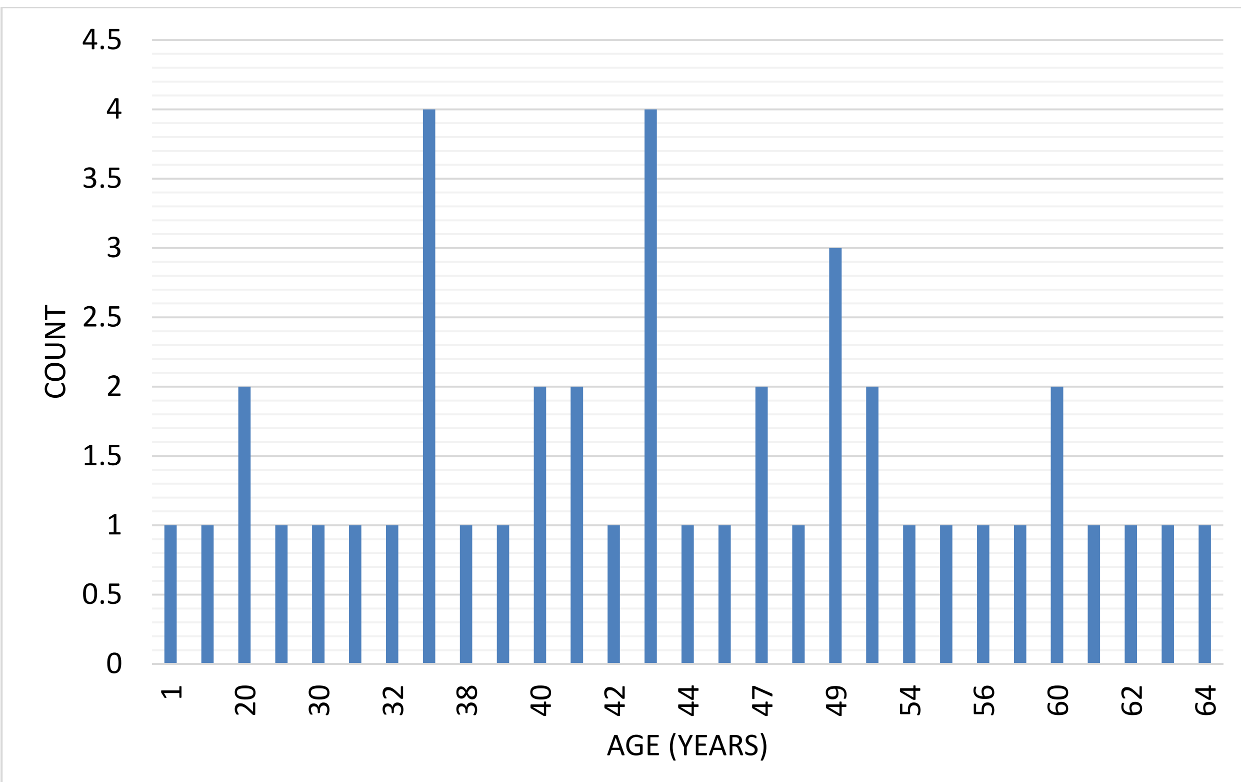

Figure 1-3
Failed Transformer Age Demographics

2
REMOVAL RATE MODELING

Data Review

Originally Hydro One sought to obtain a year-by-year prediction of the expected number of transmission substation transformer failures for the next five years. However, the supplied failure data appeared sparse in relation to the number of transformer-years experienced and consequently the derivation would not provide a usable failure hazard rate. The failure data provided for the period of 2006 through 2016 consists of 42 failures. Confidence limits for any derived hazard rate would be large using this supplied failure data as noted in Figure 2-1. For example, for the failure rate of derived from this data could be anywhere between approximately 0.6% and 2% for a 60 year old transformer using a 95% confidence band. For a 40 year old transformer the failure rate could be anywhere between approximately 0.3% and 1%.

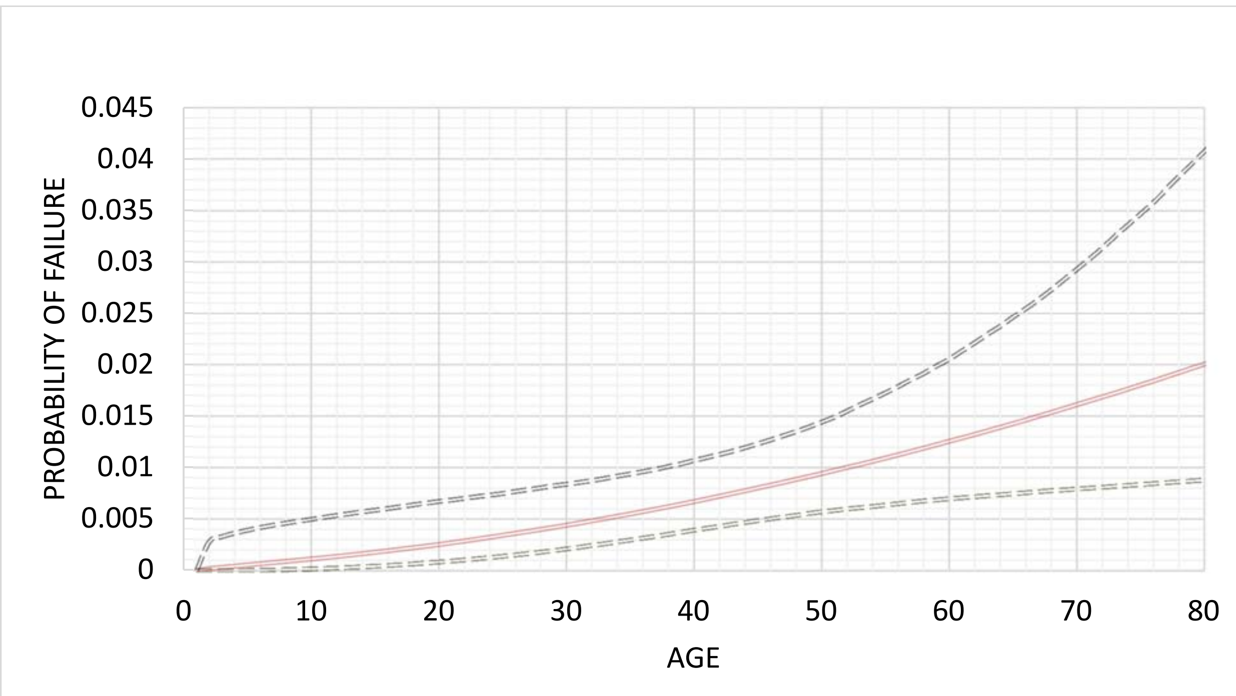

Figure 2-1
Failure Hazard Rate Derived from Spares Data

However, removed from service data is more abundant and consist of 419 transformers within a period of 1981 to first quarter 2017. The reasons for removal are not supplied in data, therefore failures and discretionary replacements cannot be distinguished. Since the reason is not supplied a time-to-event model can be developed where the event, rather than failure, is removal.

Figure 2-2 show the Service Ages of the 115 kV transformer group using data from both the removed from service (left) and failures (right). In the Service Ages plot, the horizontal axis is the age of the transformers. Each horizontal line represents a distinct transformer denoted by an index number. The failures (or removals) and non-failures are separated and then ordered by installation date. The horizontal line lengths represent the ages for which each transformer was in the record, that is, how long it was observed after the truncation date. The left end point of each horizontal line is the Enter Age. The vertical red lines are failure ages. This figure shows clearly that there were no transformers that failed before age 20 in this data set. The removed from service data provides a longer observation period and many more events than the failure data.

Figure 2-2
Service Ages for 115kV Transformer Group

Modeling

EPRI has developed a proven analytic methodology for analyzing transformer event data. The methodology has been demonstrated with a number of utilities' datasets. The modeling methodology assumes a Weibull function for the underlying data described by two parameters, shape and scale. The problem is then to develop the most likely shape and scale values. A Bayesian approach is utilized.

Analysis began with a "prior distribution" based on the results of EPRI observations of previous utilities transformer data set of in-service and failures. In the Bayesian paradigm, this current knowledge about the model parameters is expressed by placing a probability distribution on the parameters, the prior distribution. As new data, that is removal observations, becomes available, the information contained regarding the model parameters is expressed in a likelihood, which is proportional to the distribution of the observed data given the model parameters. This information (from removal data) is then combined with the prior distribution to produce a new, upgraded probability distribution formally called the posterior distribution or updated distribution. The calculation involves multidimensional integration of complicated functions and is computationally intense and a Markov Chain Monte Carlo, MCMC, method was used.

Figure 2-3 is a bivariate plot showing the calculation results for removal for this transformer population. The blue dots represent a random sample of 9,600 pairs from the updated distribution of shape and scale given the information from the data provide Hydro One. The red ellipse contains the central 95% of the distribution, that is, where most (95%) of the pairs are located. The red dot is the mean of the upgraded Weibull parameter knowledge, the expected values. From these upgraded shape and scale parameters removal predictions for currently in-service transformers can be made.

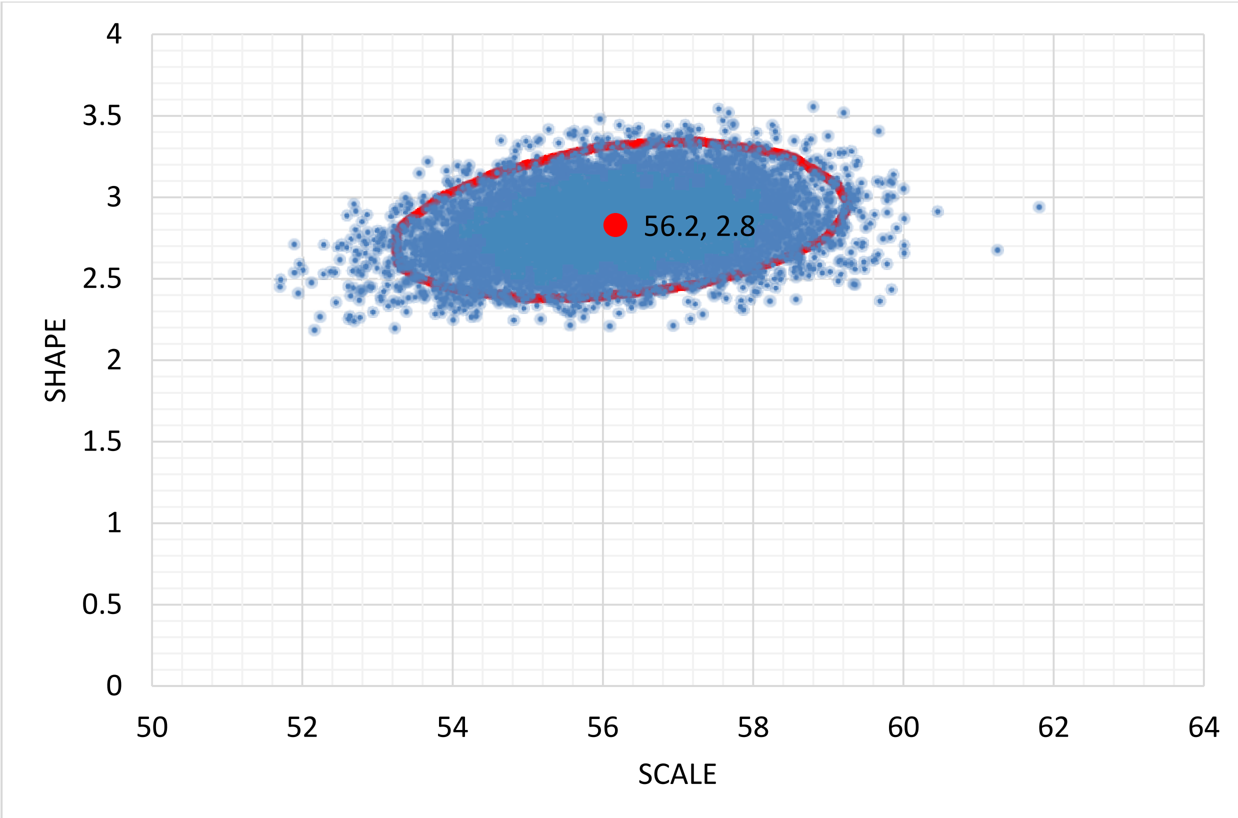

Figure 2-3
Bayesian Result 115 kV Transformers

Fitting the data to the Model

The removal rate model is verified by comparing the sample cumulative hazard function calculated from the actual event data (previously described) against the cumulative hazard functions created from the Weibull model. There are cumulative hazard functions for each MCMC observation. For each age from 0 to 100, we calculate the median cumulative hazard rate and the corresponding 95% credibility interval. This calculation provides the median cumulative hazard rate (solid red line) for the model shown in Figure 2-4. The dashed red lines give the 95% credibility interval for these calculations. The black line is the actual event data cumulative hazard function calculated using the Nelson-Aalen technique. The Nelson-Aalen technique is an established statistical technique for developing a non-parametric estimate of the cumulative hazard function based on the observed data.

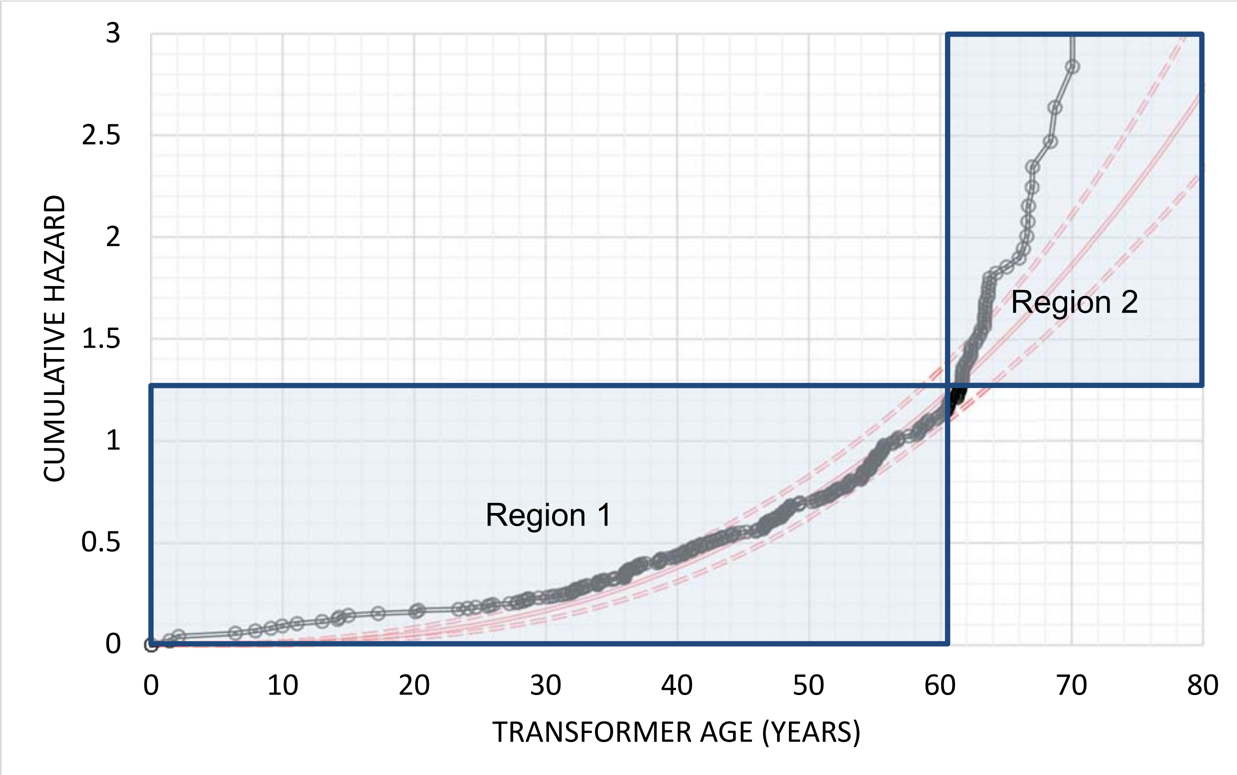

Figure 2-4
Comparison of Model and Sample Cumulative Hazard Functions 115 kV Transformers

Figure 2-4 for the 115 kV transformer group show two regions with different levels of agreement between the red and black lines. A good Weibull model fit for most of the life (Region 1) and a much steeper replacement rate (black line) than provided by the Weibull model in later life (Region 2). However, younger power transformers are rarely replaced except for failure. Therefore, Region 1 may be a reasonable model for the failure hazard rate. The break points between the two regions could indicate the following:

- The onset of a failure process that is more dominant in older units.
- The result of discretionary replacement decisions.
- Some combination of both failure process and discretionary replacement.

Since the reasons for removal are not noted, failures and discretionary replacements cannot be distinguished.

Modeling Assumptions

- The starting data is complete and contains all removals and in-service units for the period within 1981 through first quarter 2017.
- The criteria for removal have been constant over the historical period being analyzed.
- Future criteria for removals will be the same as in the past.

- Any external effects on removal rates (e.g. budget constraints) were constant over the historical period and will be unchanged over the forecast period.
- Underlying wear-out processes will not change.

Modeling Results

There are currently 276 115 kV family transformers in service of various ages. Based on the age of each individual transformer, the distributions of the number of removals was predicted from a Monte Carlo simulation.

Each of the 9,600 pair results from the analyses results (Figure 2-3) is used in a Monte Carlo simulation to generate the expected number of removals. Each shape and scale pair defines a Weibull distribution. This distribution is applied to each of the in-service transformers and the number of removals are summed for the total population for that particular distribution.

The resulting histogram of the sum of the number of removals recorded in each plot (Figure 2-5) gives the probability distribution of removals. The entire process is then repeated for the next year with each transformer's age incremented by one.

Figure 2-5 shows the predicted number of removals of the currently in-service transformers for each of the next five years and the five year total.

The figure can be interpreted as probability distributions. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 18 removals, we can say that we are 99% certain that the number of transformer removals will be 18 or fewer.

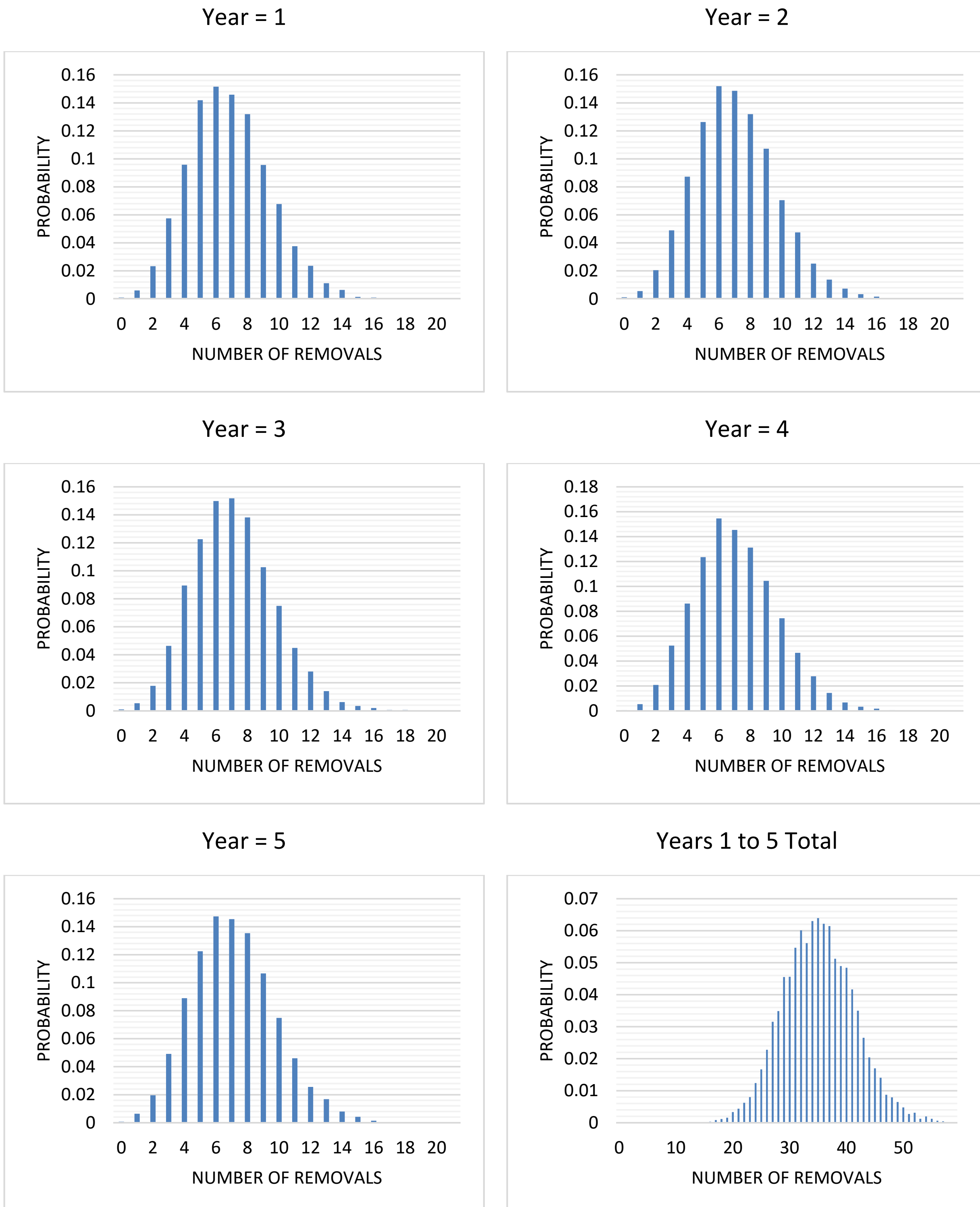

Figure 2-5
Predicted In-Service Transformer Removals for Each of the Next Five Years 115 kV Transformers

3
REMOVAL ANALYSIS RESULTS

Using the data provided by Hydro One describe in Chapter 1. The following chapter provides the results of the application of the model describe in Chapter 2 for each of the transformer groupings. The analyses were grouped by transformer high side voltages, 115 kV, 230 kV and 500 kV. More granular groupings, for example by number of phases or MVA, were not feasible because of the lack of data or the reduced number of data points that would result.

Each group results will include the following:

In-service Age Demographics: Shows the age distribution in years for the specific transformer group.

Removed from Service: Shows the age distribution in years for the specific transformer group.

Service Eras: Provides information about the completeness of the data set. The horizontal axis is in years. Each horizontal line represents a transformer recorded. The black lines show the installation dates. If a line is gray, the transformer is still in service. If a line turns red, the transformer has been removed from service on the date of the color change.

Service Ages: Provides information about the completeness of the data set. The horizontal axis is the age of the transformers. Each horizontal line represents a distinct transformer denoted by an index number. The removals and in-service are separated and then ordered by installation date. The horizontal line lengths represent the ages for which each transformer was in the record, that is, how long it was observed after the truncation date. The left end point of each horizontal line is the Enter Age. The vertical red lines are removal ages.

Removal Hazard Function: The hazard function provides the rate of removal. It can be interpreted as the conditional probability of removal in the next unit of time conditioned on surviving up to the beginning of that time unit.

Survival Function: The survival function provide the rate of survival (not being removed). Shows the expected rate of survival per year as the transformer ages. The middle line is the mean value. The top and bottom lines show the 95% confidence limits. The black line is the actual event data survival function calculated using the Kaplan-Meier technique. The Kaplan-Meier technique is an established statistical technique for developing a non-parametric estimate of the survival function based on the observed data.

Yearly Removal Predictions for the Next Five Years: Shows the predicted number of removals of the currently in-service transformers for each of the next five years. The hazard functions has been convoluted with the corresponding in-service population to provide forecasts of anticipated removals.

Cumulative Five Year Removal Predictions: Shows the cumulative predicted number of removals of the currently in-service transformers for next the five years.

115 kV Removal Analysis

The following provides the results of the 115 kV transformer group analyzed using the method described in Chapter 2. Table 3-1 shows the number of transformers in-service and removed from service.

Table 3-1
Transformer Group Data 115 kV

Group	In-service	Removed from Service
115 kV	276	297

Age Demographics 115 kV

Figures 3-1 and 3-2 show the age demographics for both in service and removed from service transformer units.

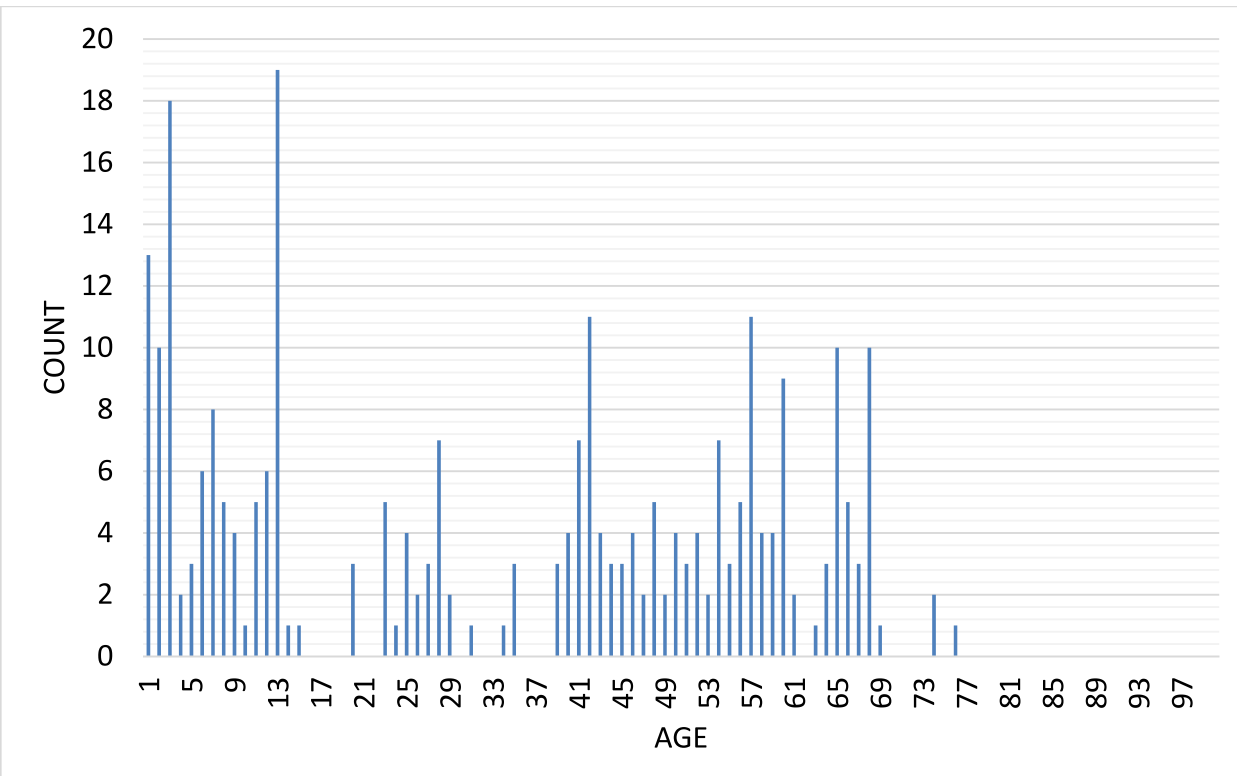

Figure 3-1
Age Demographics In-service 115 kV

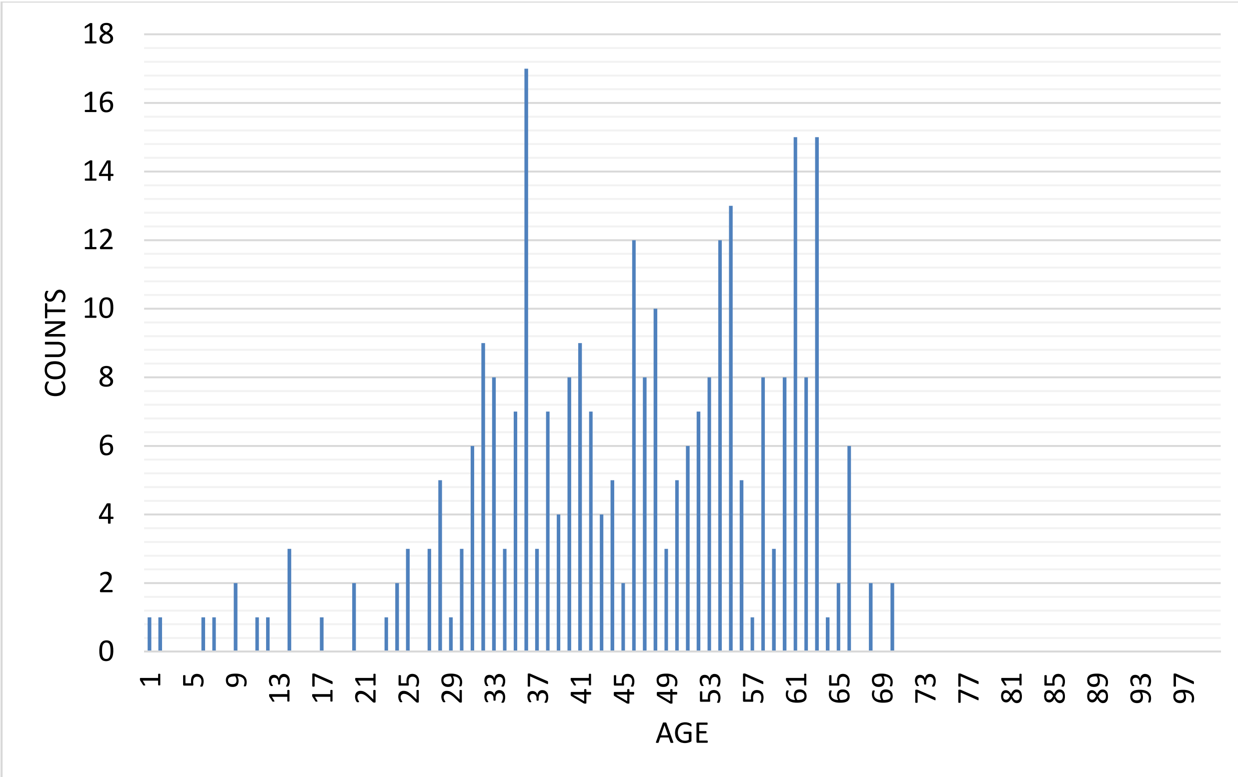

Figure 3-2
Age Demographics Removed From Service 115 kV

Figures 3-3 and 3-4 show the Service Eras and Service Ages of the 115 kV transformer group. The service eras and service ages plots shows the observation period for this transformer group where the observation period began in 1981.

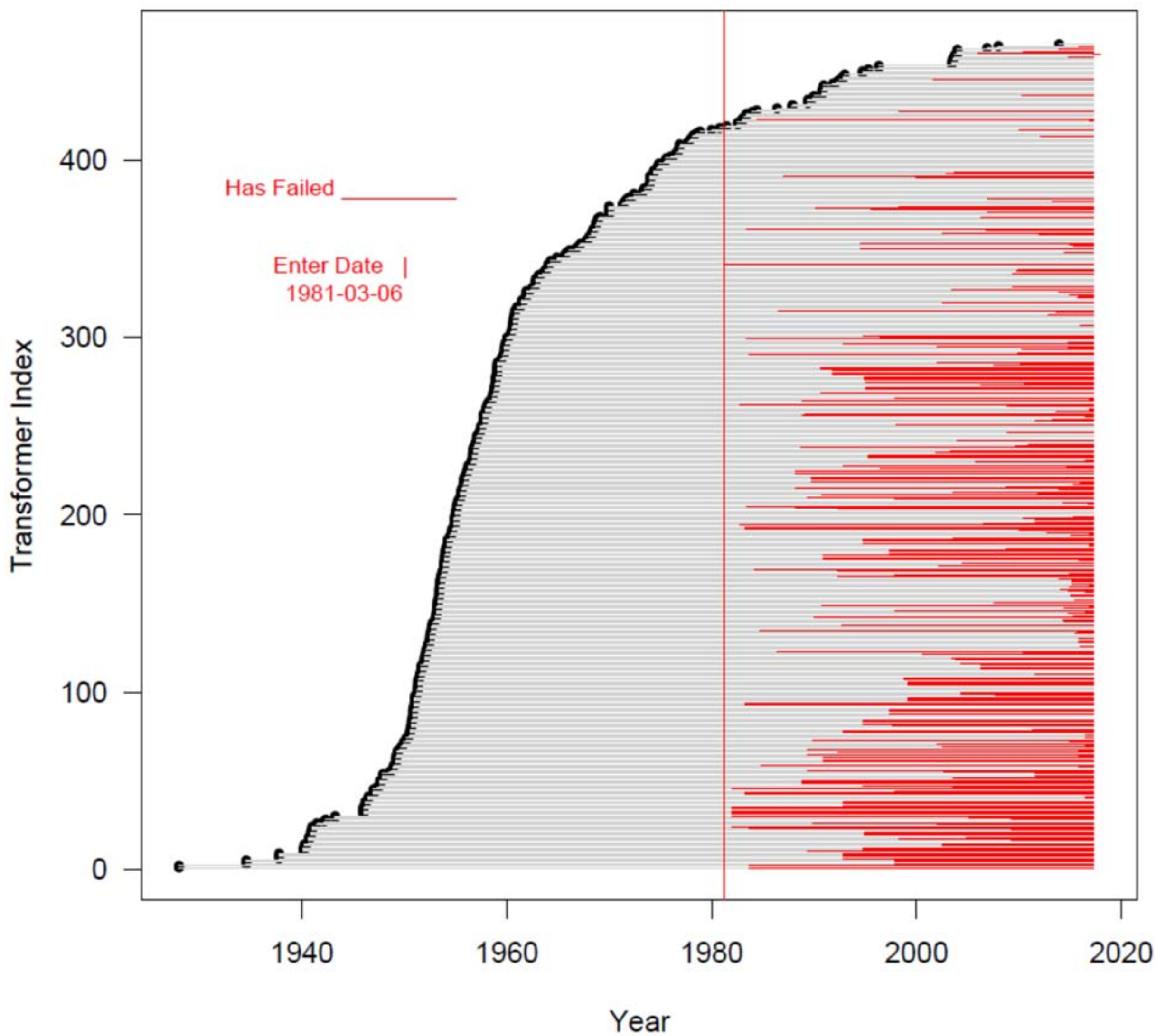

Figure 3-3
Service Eras 115 kV

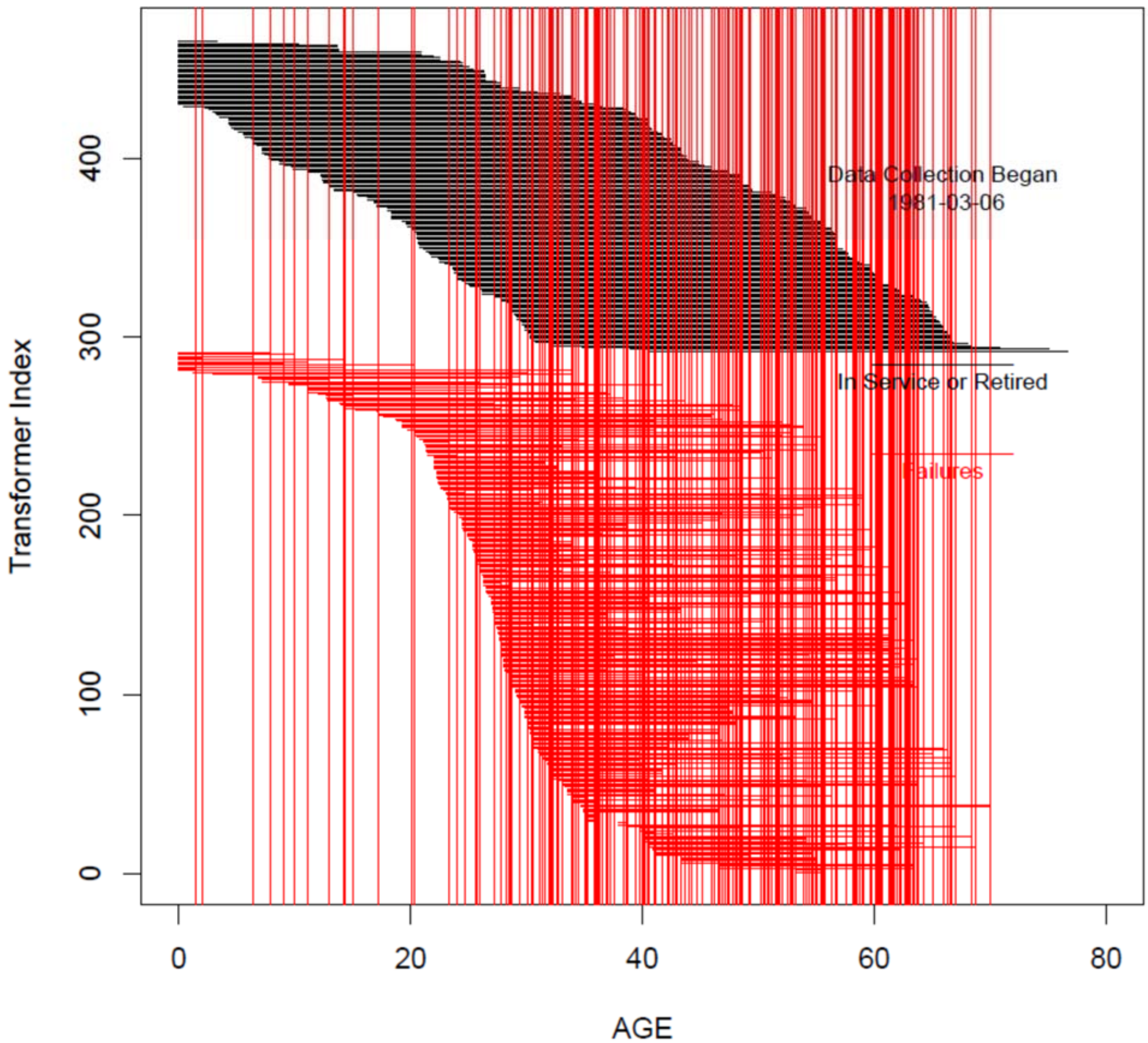

Figure 3-4
Service Ages 115 kV

Removal Hazard Rate 115 kV

Figure 3-5 show the removal rate developed using the in-service and removed from service data provided for the 115 kV transformer. In the figure, probability of a 40 year old transformer being removed in its next year of life ranges from 2.3% to 3%. For a 60 year old transformer the probability of being removed in its next year of life ranges from 4.7% to 6.7%. Note the 95% confidence intervals. The bands become larger above age 60, reflecting the sparse number of recorded removals in these regions.

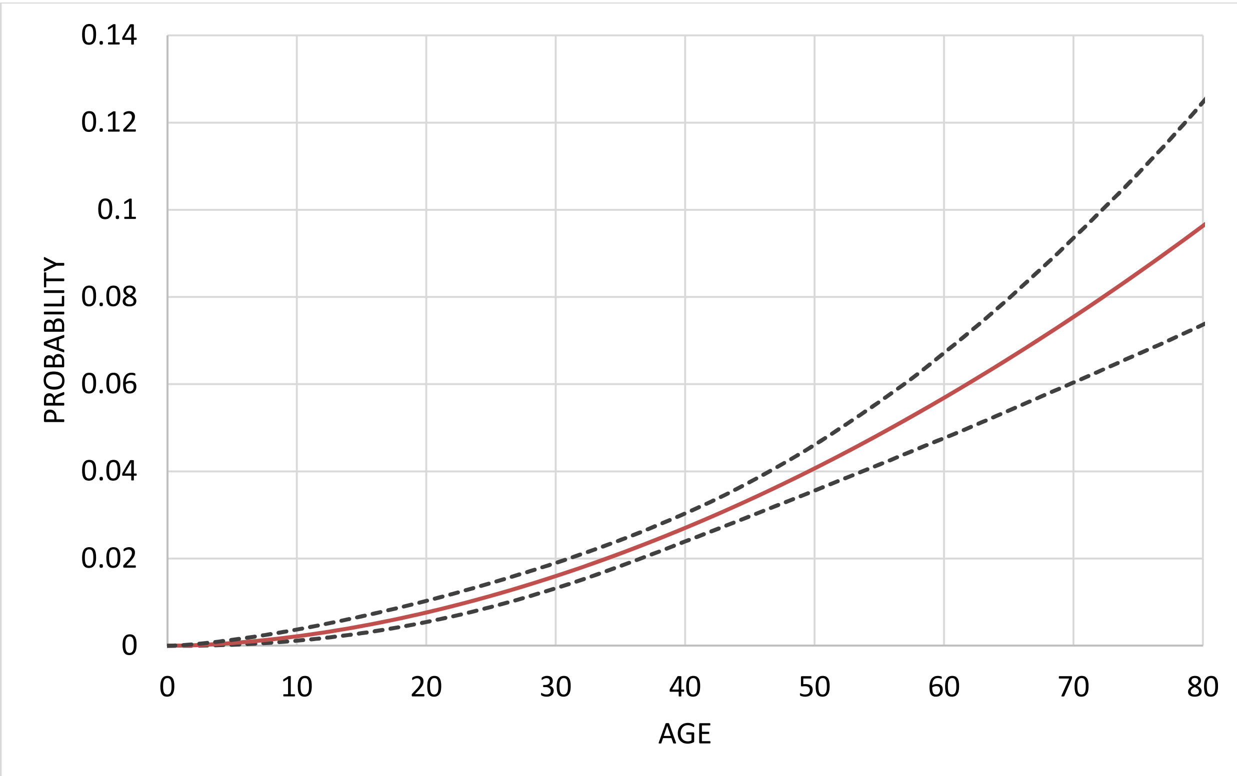

Figure 3-5
Removal Hazard Rate 115 kV

Survival Function 115 kV

Figure 3-6 shows the survival function developed using the in-service and removed from service data provided for the 115 kV transformer group. In the figure, the mean probability of a 40 year old transformer surviving (not being removed) in its next year of life ranges from 62% to 73%.

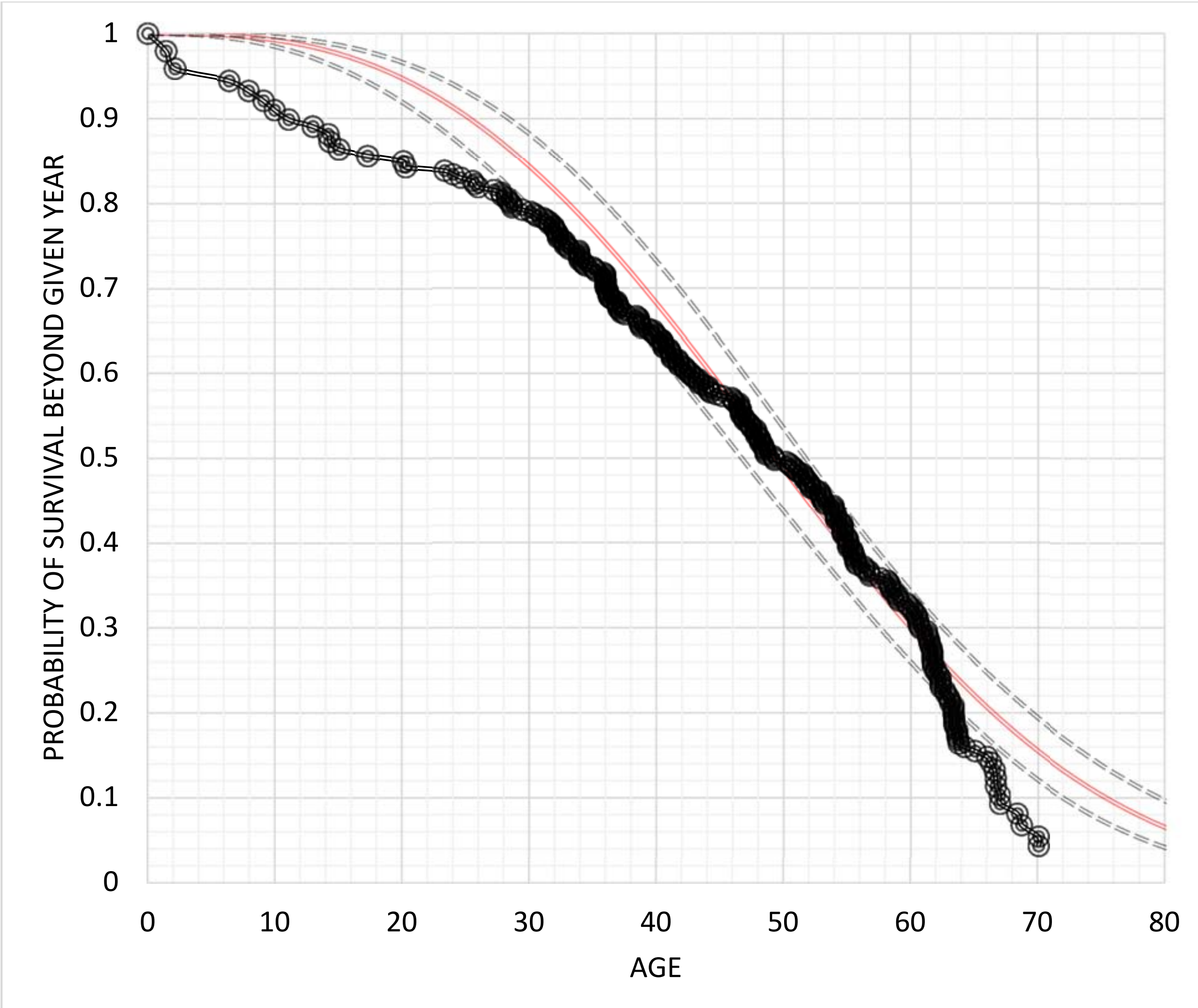

Figure 3-6
Survival Function 115 kV

Forecasting Removals

Figures 3-7 and 3-8 show the predicted number of transformer removals for each of the next five years. The predicted number of removals for each year and five year total shown are in Figure 3-7. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 18 removals, we can say that we are 99% certain that the number of transformer removals will be 18 or fewer. Figure 3-8 presents the cumulative results combining each year of the five year period.

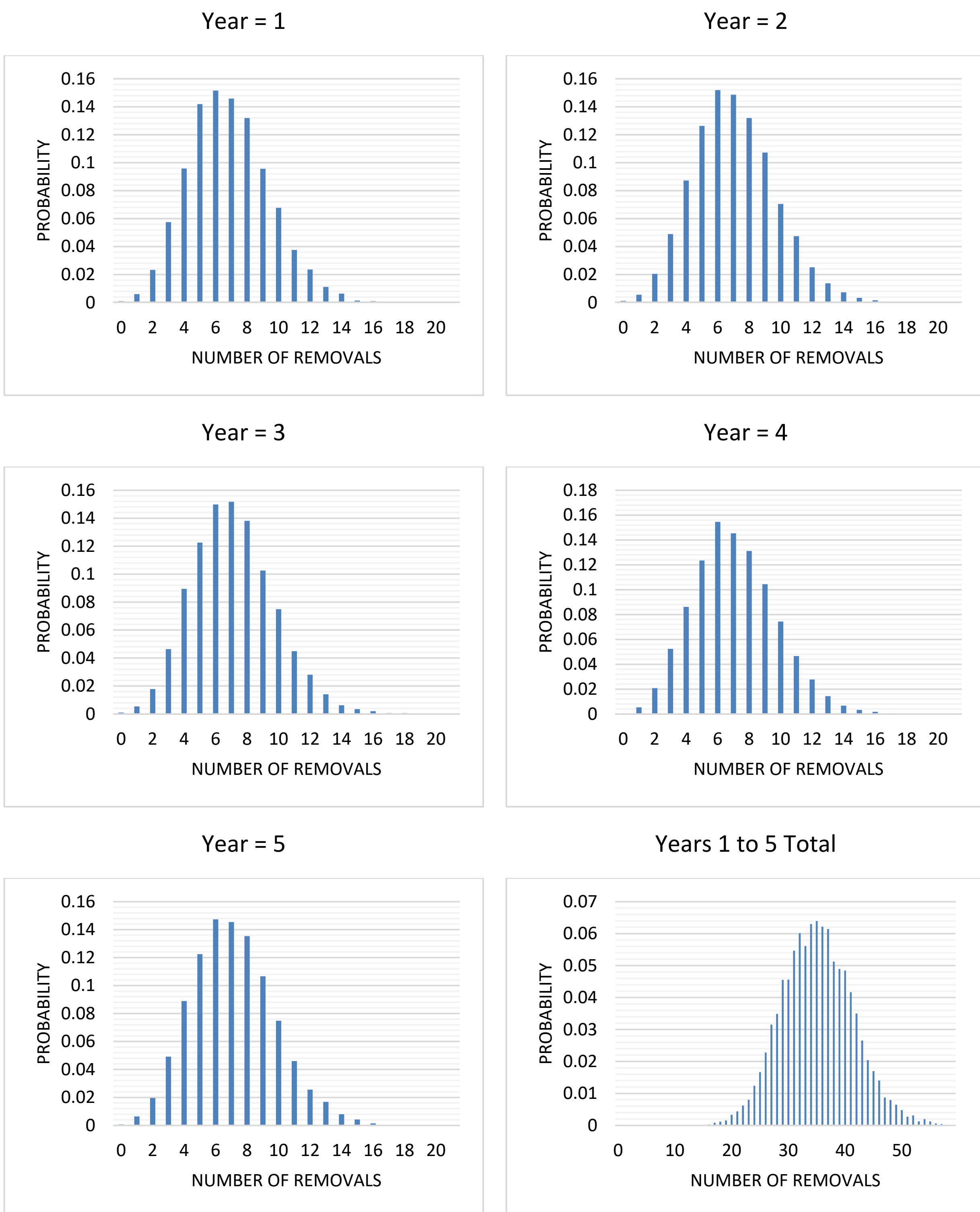

Figure 3-7
Predicted In-Service Transformer Removals for Each of the Next Five Years 115 kV Transformers

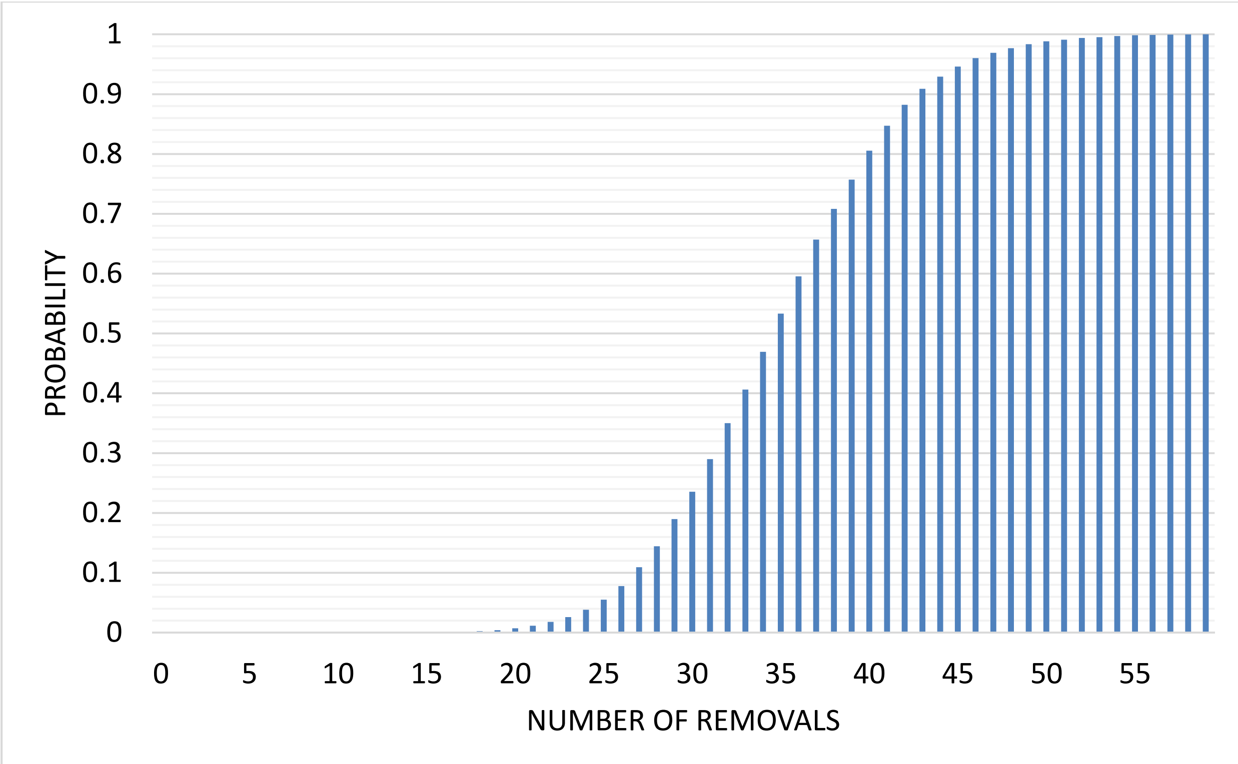

Figure 3-8
Cumulative Probability of In-Service Transformer Removals Next Five Years 115 kV

230 kV Non-Auto Removal Analysis

The following provides the results of the 230 kV Non-Auto transformer group analyzed using the method describe in Chapter 2. Table 3-2 shows the number of transformers in-service and removed from service.

Table 3-2
Transformer Group Data 230 kV Non-Auto

Group	In-service	Removed from Service
230 kV Non-Auto	303	76

Age Demographics 230 kV Non-Auto

Figures 3-9 and 3-10 show the age demographics for both in service and removed from service transformer units.

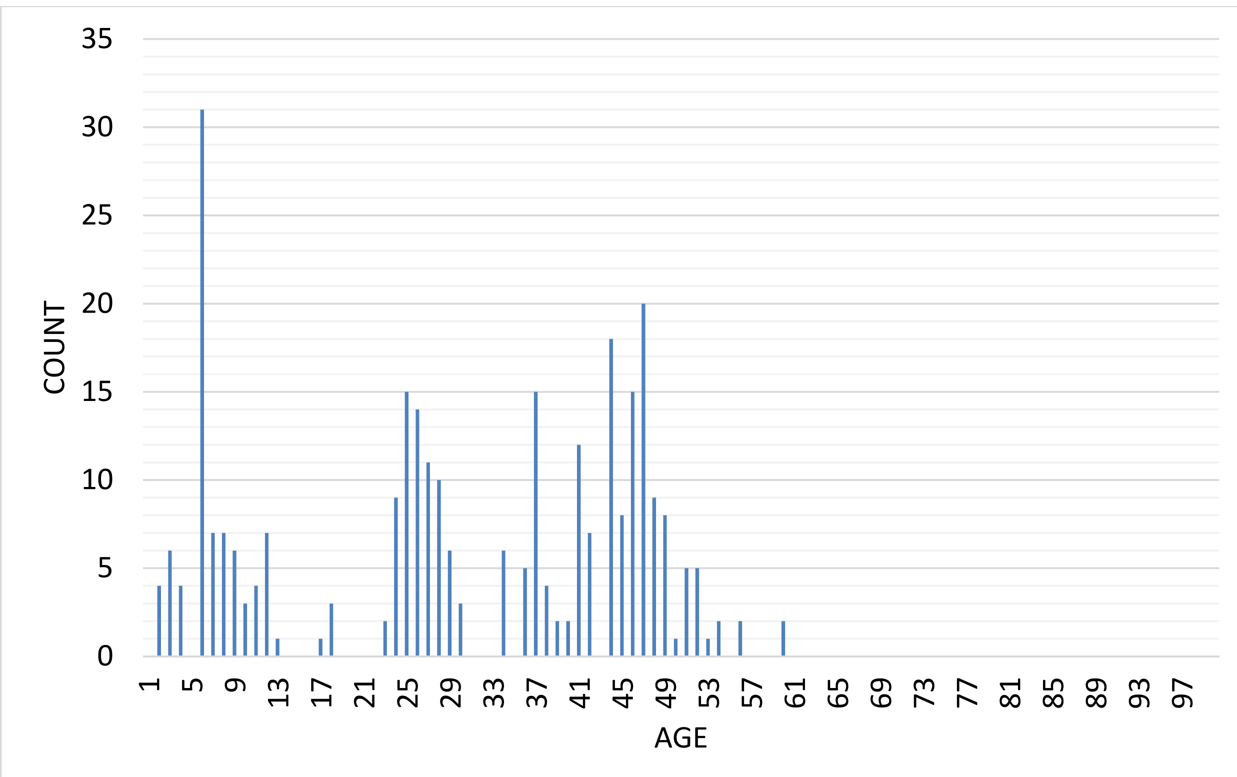

Figure 3-9
Age Demographics In-service 230 kV Non-Auto

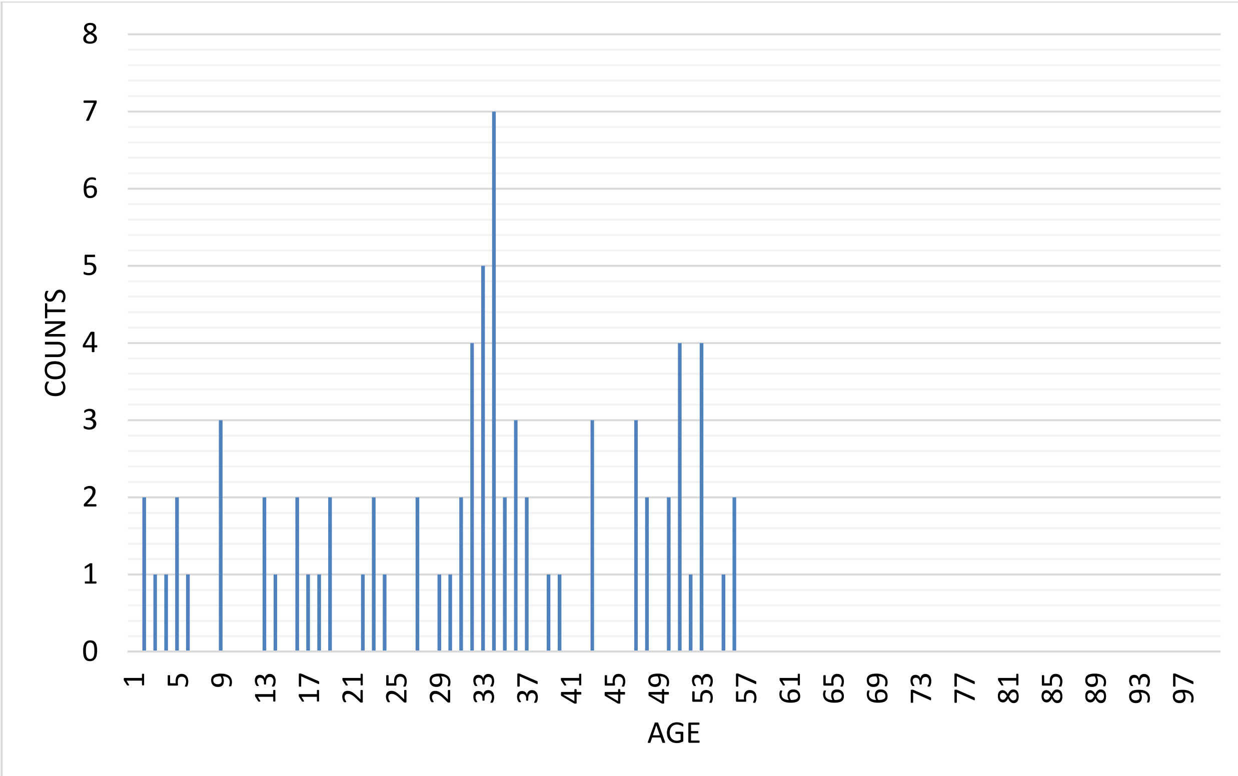

Figure 3-10
Age Demographics Removed From Service 230 kV Non-Auto

Figures 3-11 and 3-12 show the Service Eras and Service Ages of the 230 kV Non-Auto transformer group. The service eras and service ages plots shows the observation period for this transformer group where the observation period began in 1981.

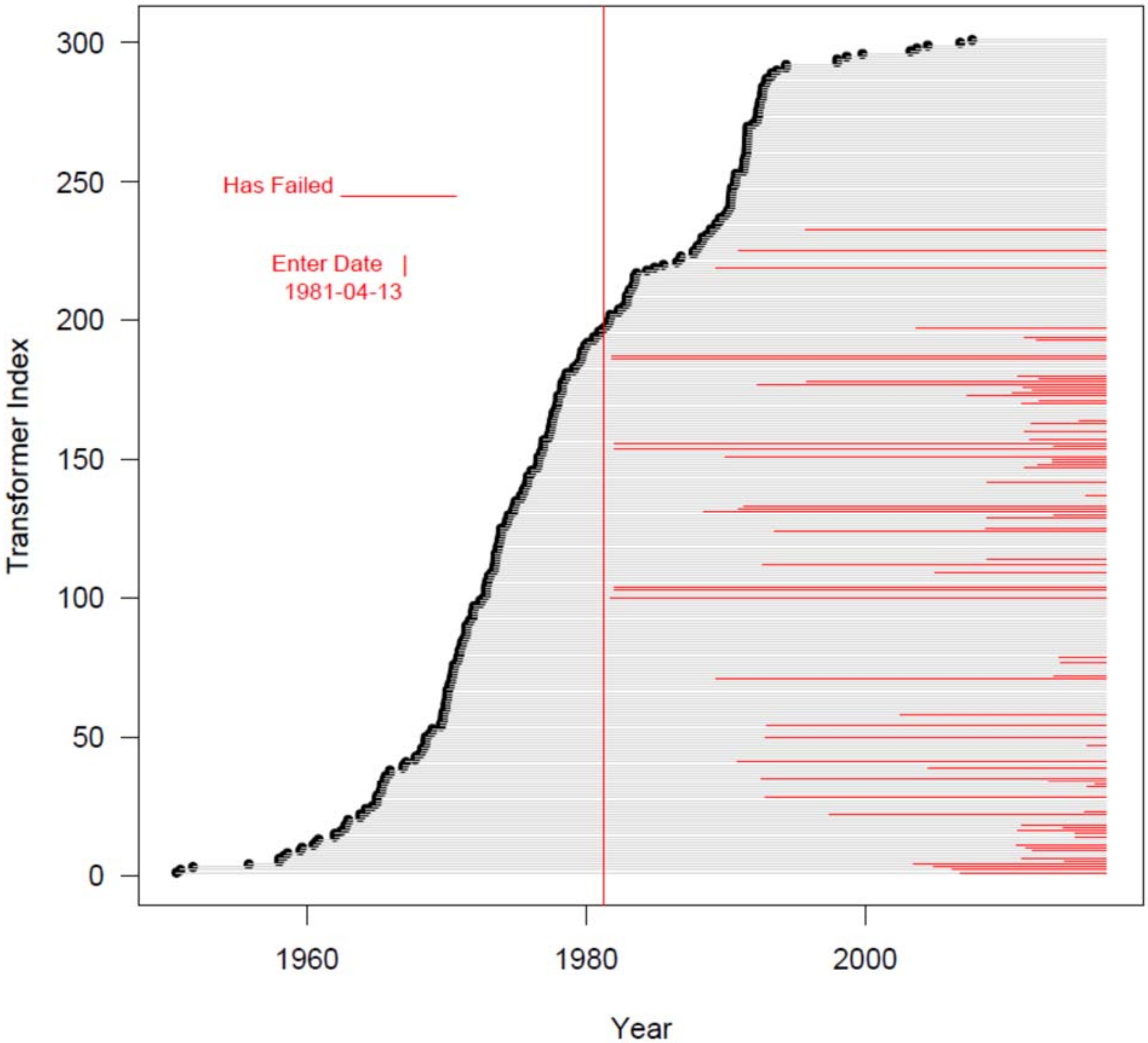

Figure 3-11
Service Eras 230 kV Non-Auto

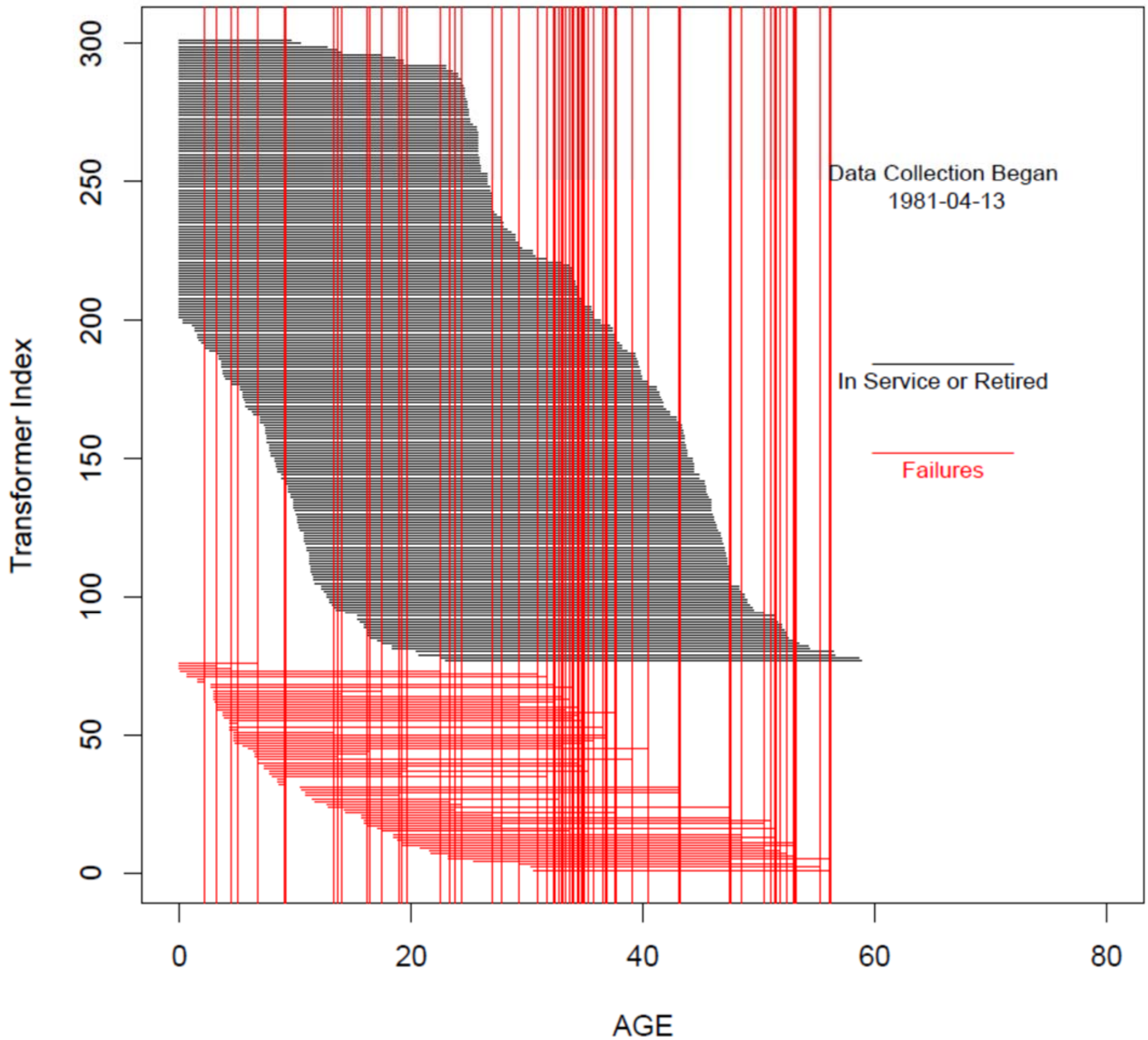

Figure 3-12
Service Ages 230 kV Non-Auto

Removal Hazard Rate 230 kV Non-Auto

Figure 3-13 show the removal rate developed using the in-service and removed from service data provided for the 230 kV Non-Auto transformer group. In the figure, probability of a 40 year old transformer being removed in its next year of life ranges from 1% to 1.9%. For a 60 year old transformer the probability of being removed in its next year of life ranges from 1.3% to 3.2%. Note the 95% confidence intervals. The bands become larger above age 50, reflecting the sparse number of recorded removals in these regions.

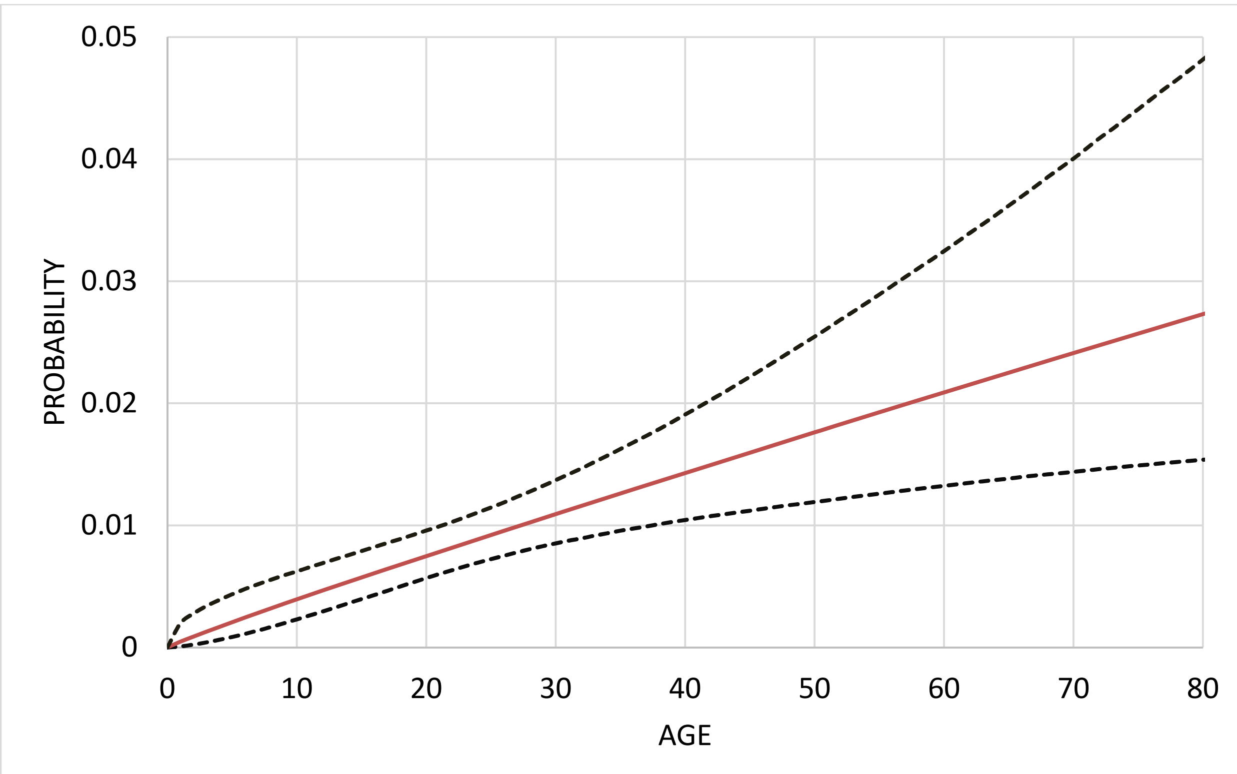

Figure 3-13
Removal Rate 230 kV Non-Auto

Survival Function 230 kV Non-Auto

Figure 3-14 show the survival function developed using the in-service and removed from service data provided for the 230 kV Non-Auto transformer group. In the figure, the mean probability of a 40 year old transformer surviving (not being removed) in its next year of life ranges from 68% to 79%.

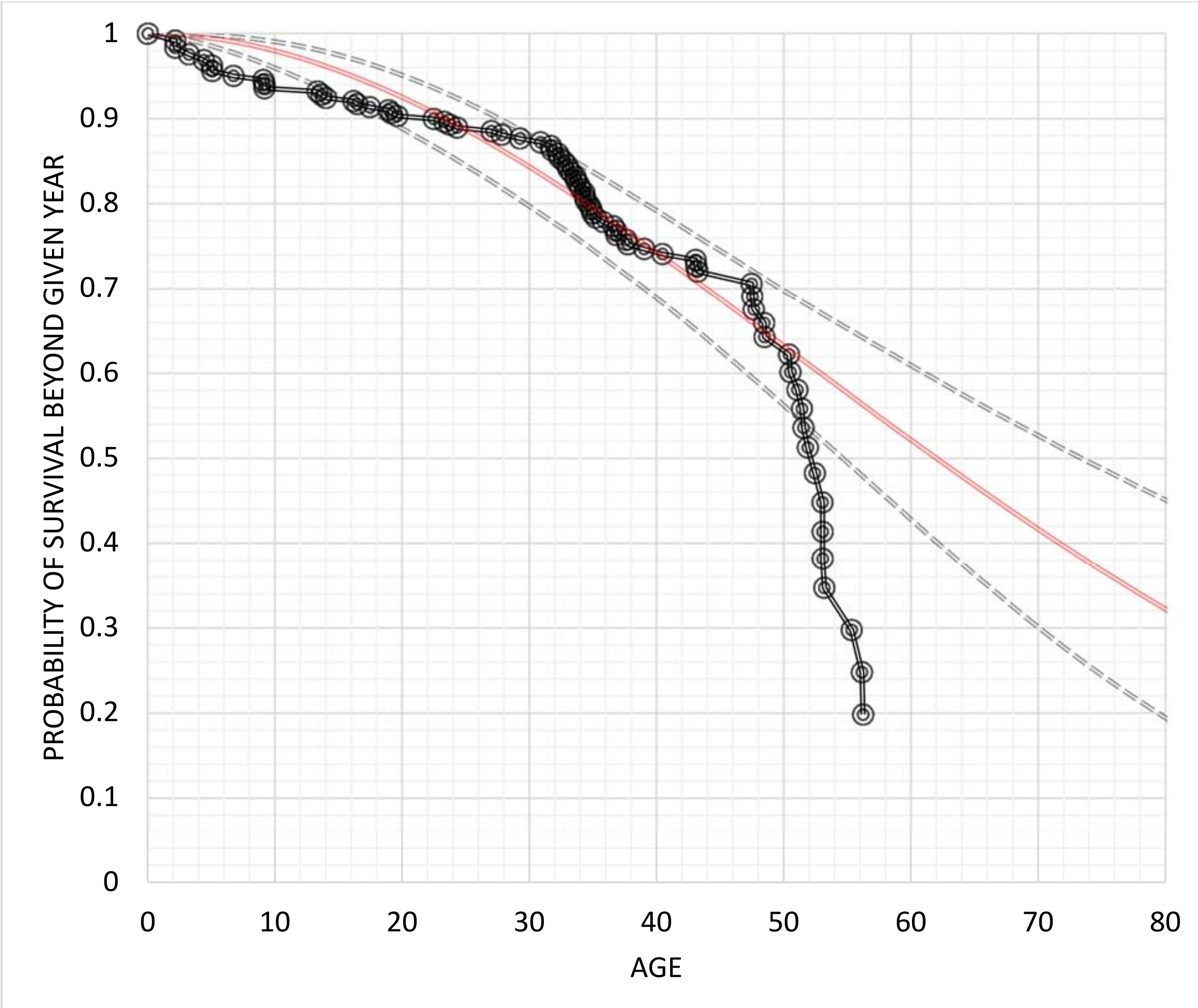

Figure 3-14
Survival Function 230 kV Non-Auto

Forecasting Removals

Figures 3-15 and 3-16 show the predicted number of transformer removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-15. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 8 removals, we can say that we are 99% certain that the number of transformer removals will be 8 or fewer. Figure 3-16 presents the cumulative results combining each year of the five year period.

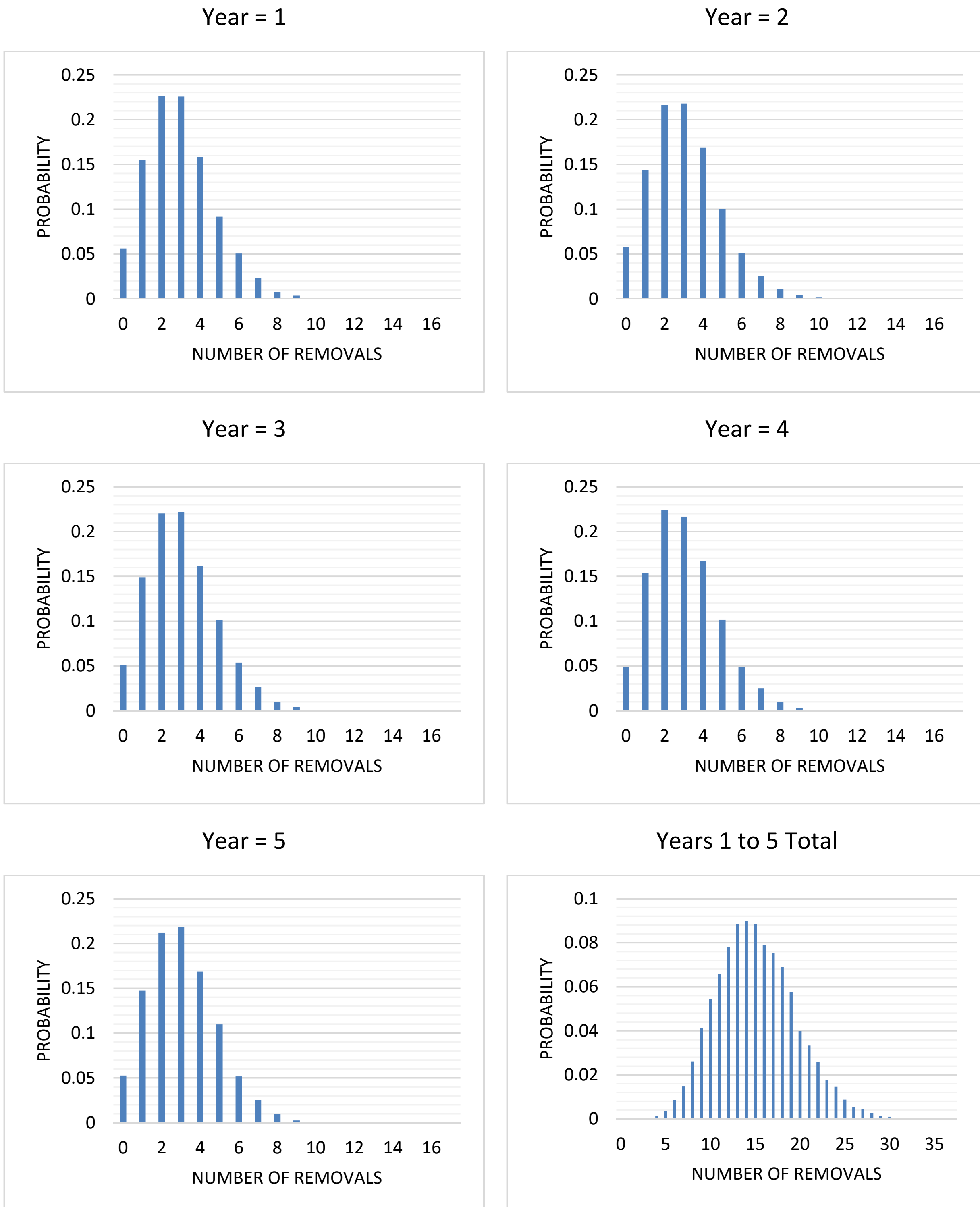

Figure 3-15
Predicted In-Service Transformer Removals for Each of the Next Five Years 230 kV Non-Auto

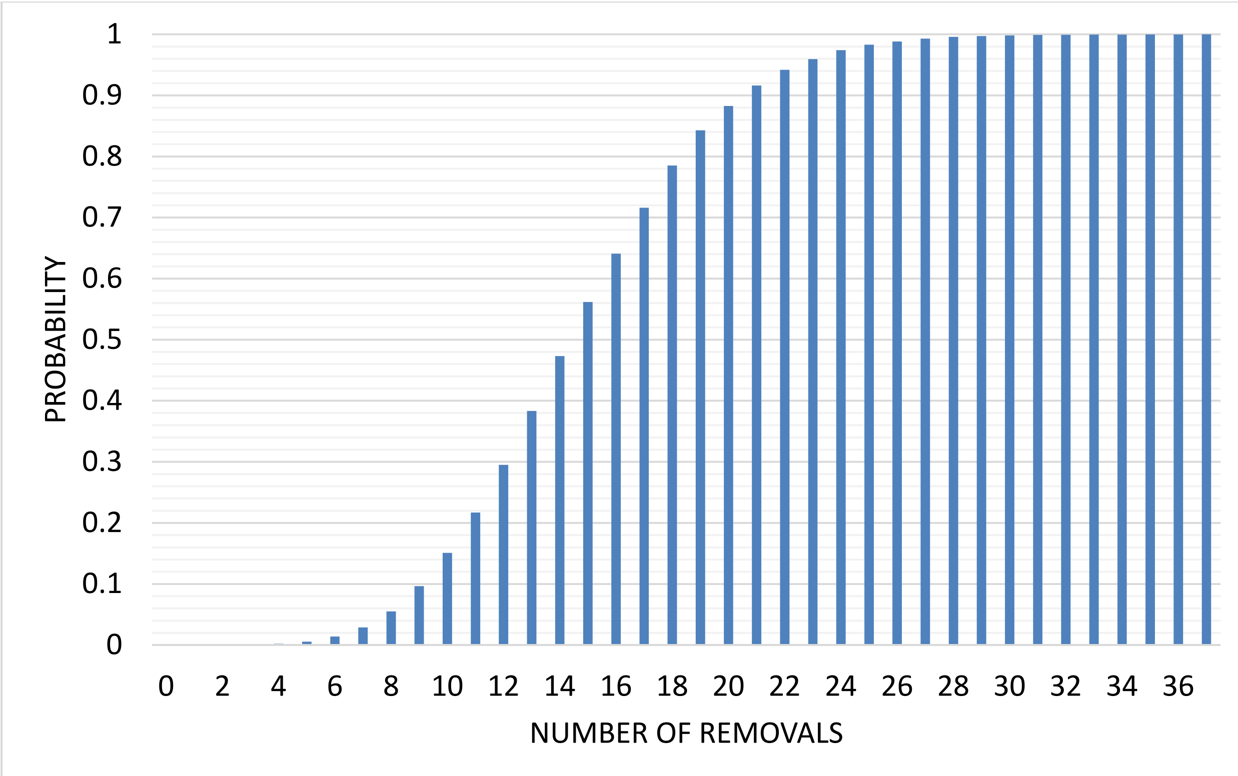

Figure 3-16
Cumulative Probability of In-Service Transformer Removals Next Five Years 230 kV Non-Auto

230 kV Auto Removal Analysis

The following provides the results of the 230 kV Auto transformer group analyzed using the method describe in Chapter 2. Table 3-3 shows the number of transformers in-service and removed from service.

Table 3-3
Transformer Group Data 230 kV Auto

Group	In-service	Removed from Service
230 kV Auto	94	25

Age Demographics 230 kV Auto

Figures 3-17 and 3-18 show the age demographics for both in service and removed from service transformer units.

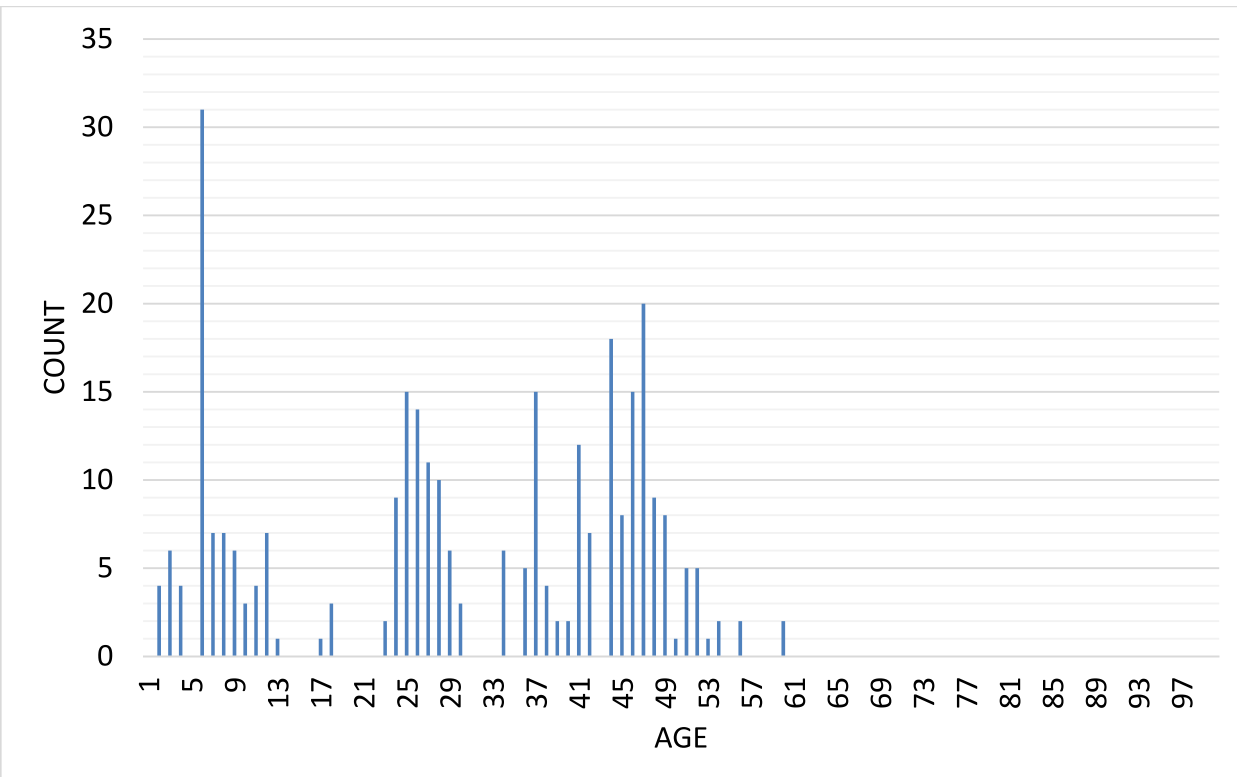

Figure 3-17
Age Demographics In-service 230 kV Auto

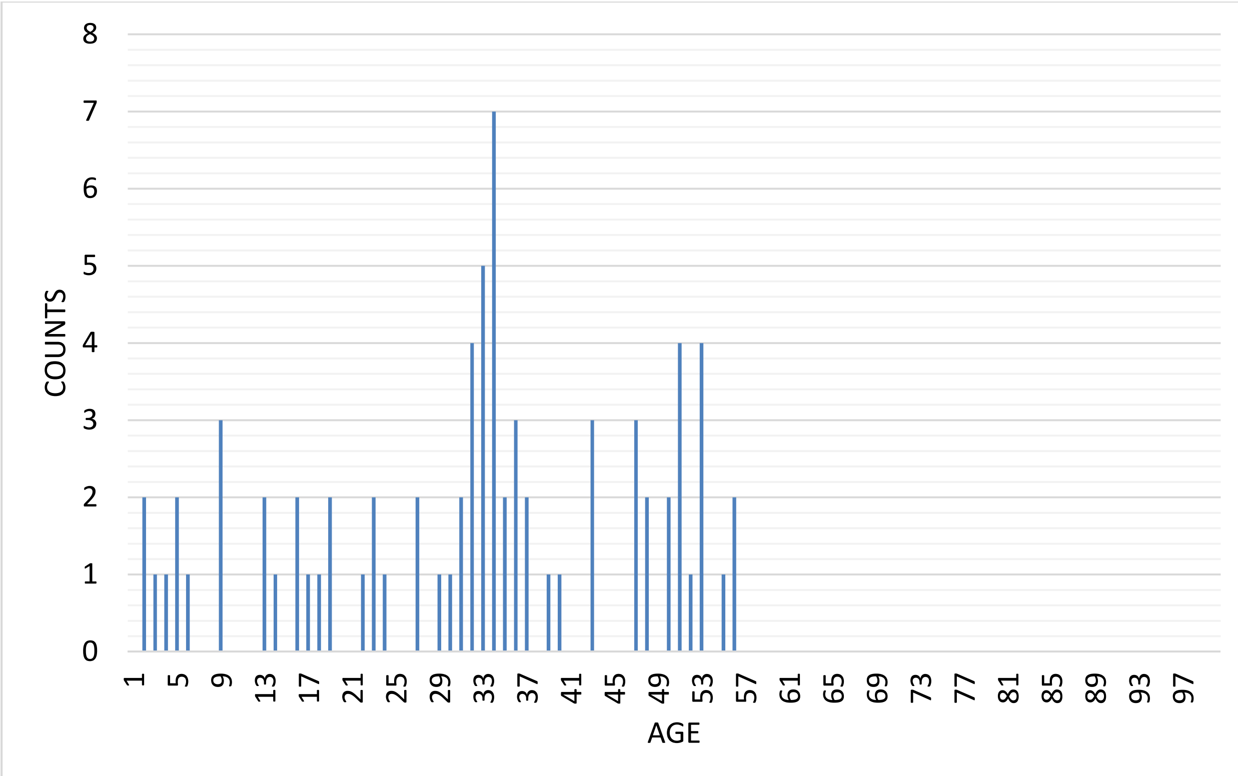

Figure 3-18
Age Demographics Removed From Service 230 kV Auto

Figures 3-19 and 3-20 show the Service Eras and Service Ages of the 230 kV Auto transformer group. The service eras and service ages plots shows the observation period for this transformer group where the observation period began in 1981.

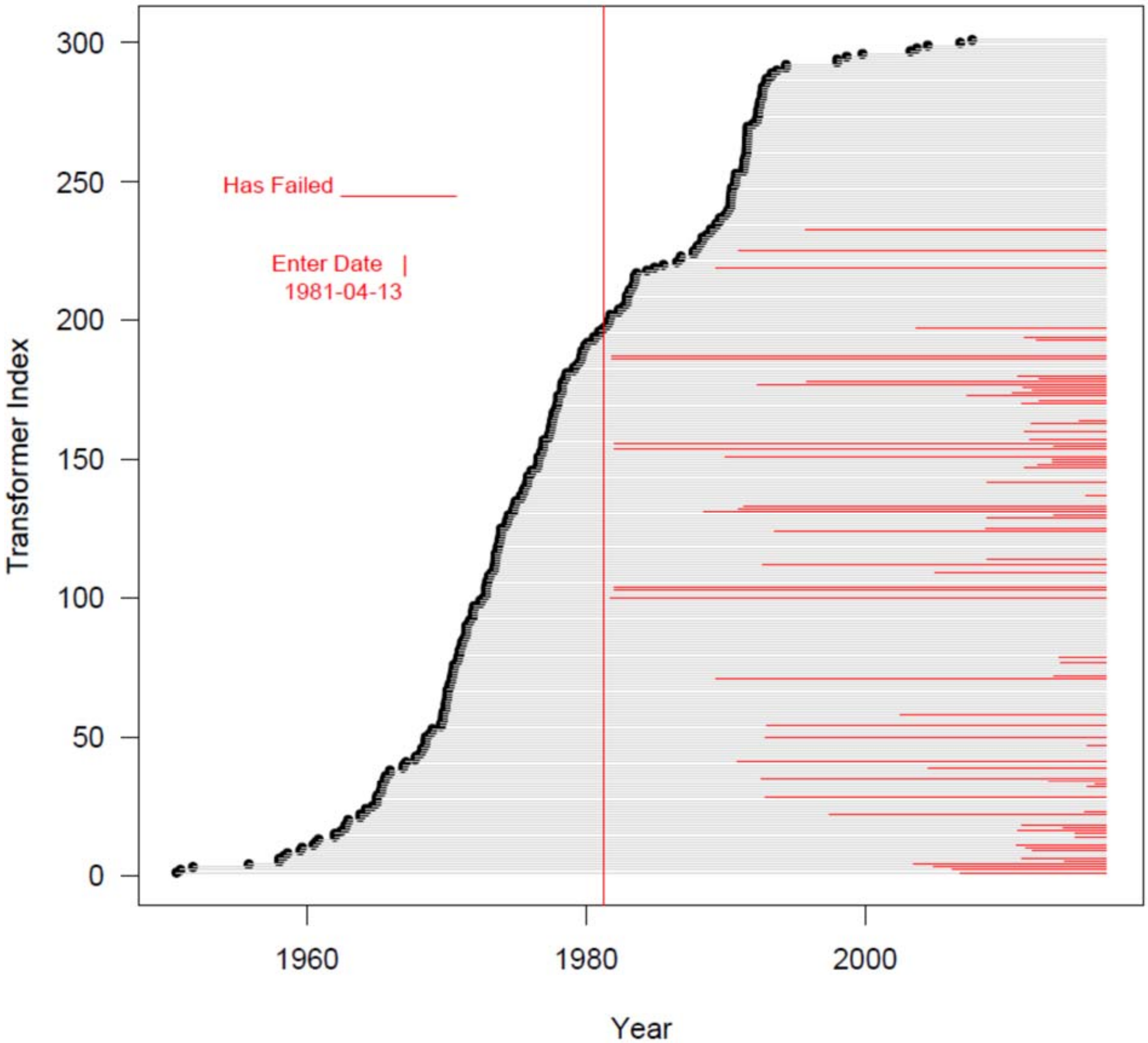

Figure 3-19
Service Eras 230 kV Auto

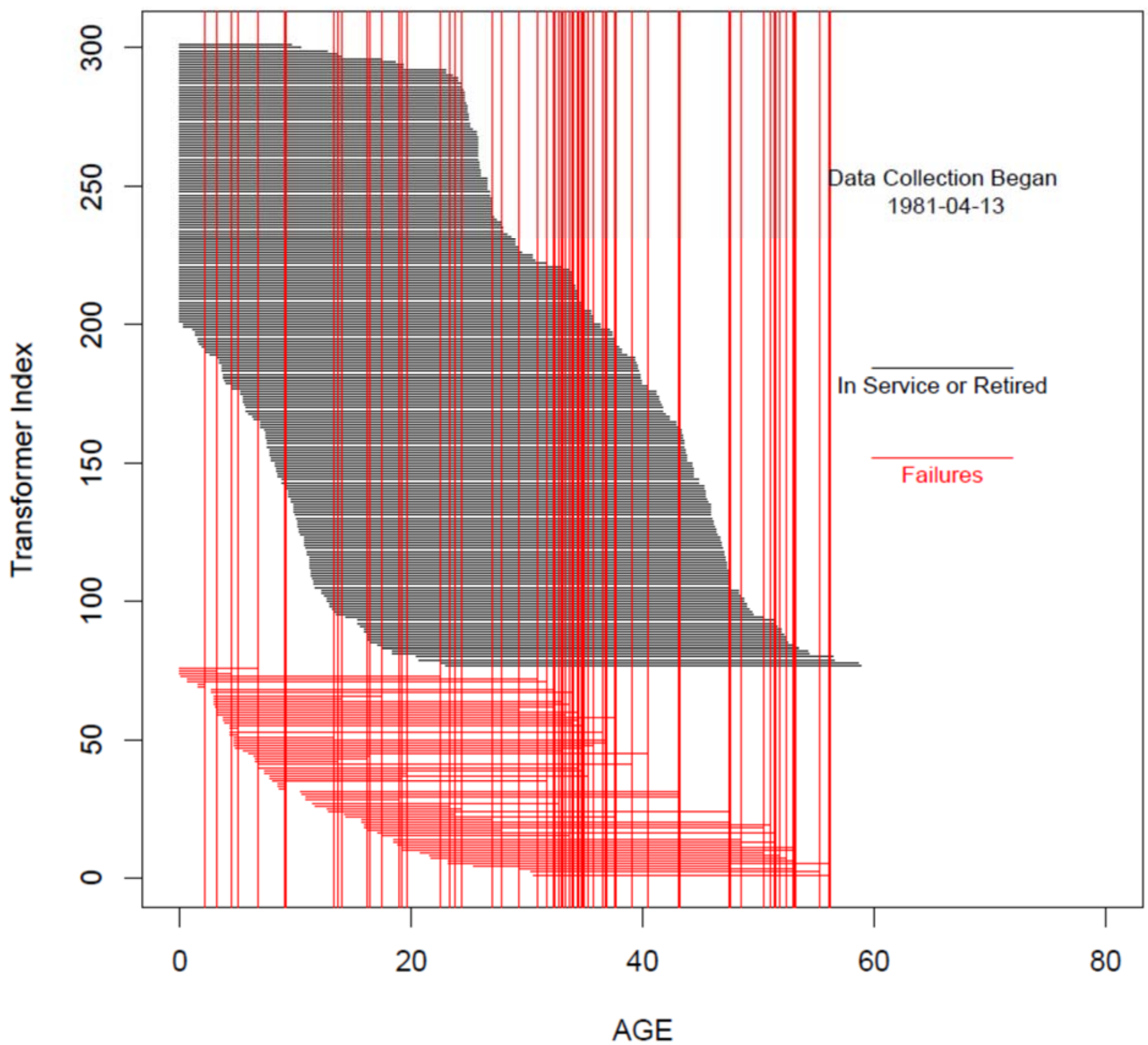

Figure 3-20
Service Ages 230 kV Auto

Removal Hazard Rate 230 kV Auto

Figure 3-21 show the removal rate developed using the in-service and removed from service data provided for the 230 kV Auto transformer. In the figure, probability of a 40 year old transformer being removed in its next year of life ranges from 0.01% to 1.6%. For a 60 year old transformer the probability of being removed in its next year of life ranges from 0.01% to 3.2%. Note the 95% confidence intervals. The bands become larger above age 50, reflecting the sparse number of recorded removals in these regions.

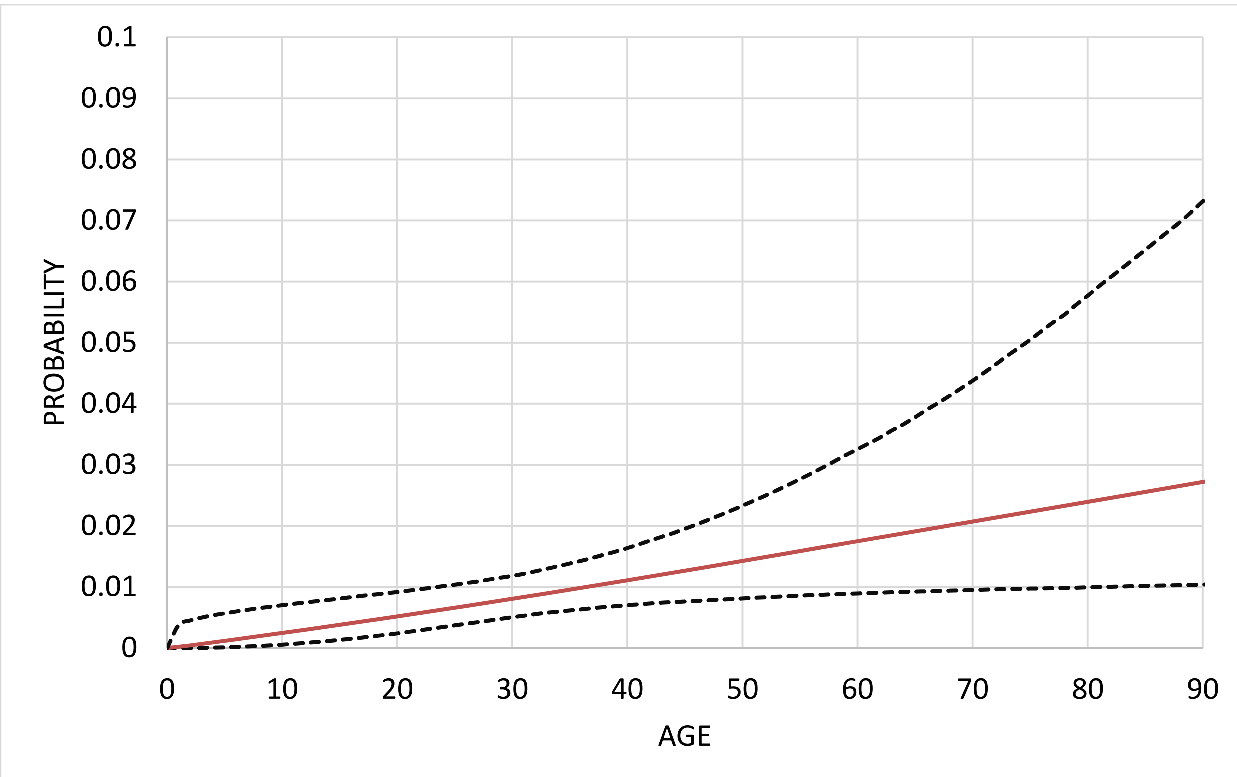

Figure 3-21
Removal Rate 230 kV Auto

Survival Function 230 kV Auto

Figure 3-22 show the survival function developed using the in-service and removed from service data provided for the 230 kV Auto transformer group. In the figure, the mean probability of a 40 year old transformer surviving (not being removed) in its next year of life ranges from 70% to 88%.

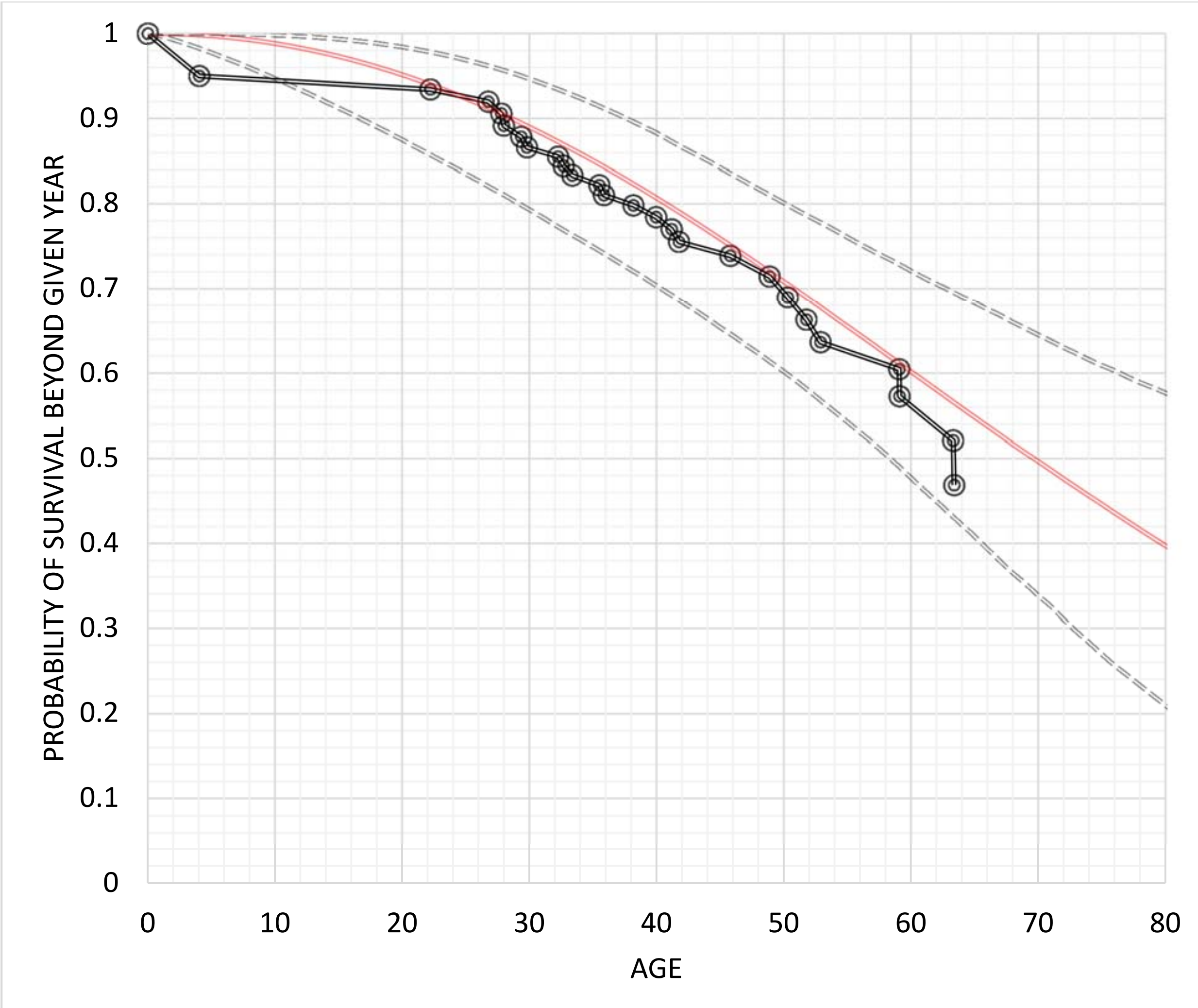

Figure 3-22
Survival Function 230 kV Auto

Forecasting Removals

Figures 3-23 and 3-24 show the predicted number of transformer removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-23. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 4 removals, we can say that we are 99% certain that the number of transformer removals will be 4 or fewer. Figure 3-24 presents the cumulative results combining each year of the five year period.

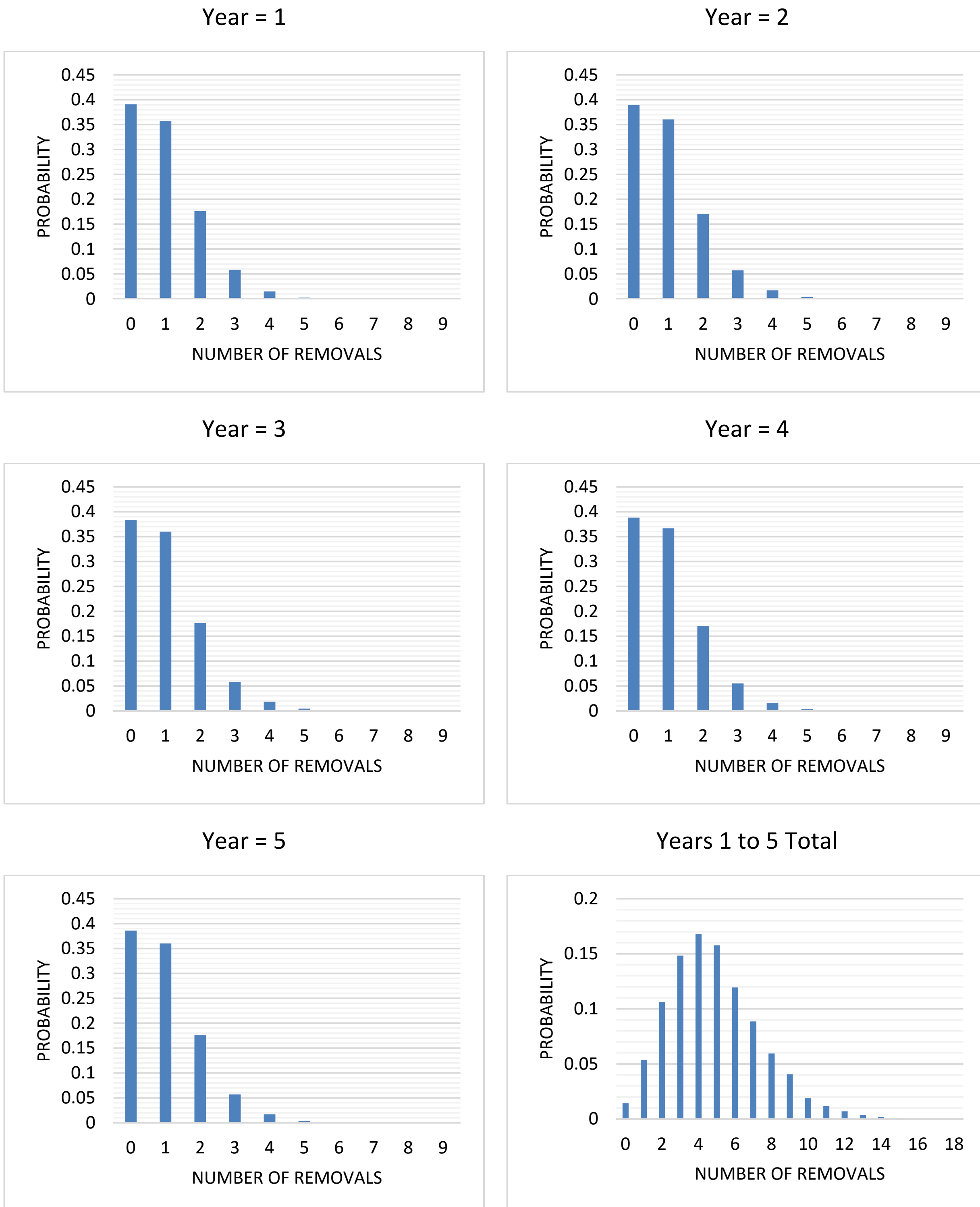

Figure 3-23
Predicted In-Service Transformer Removals for Each of the Next Five Years 230 kV Auto

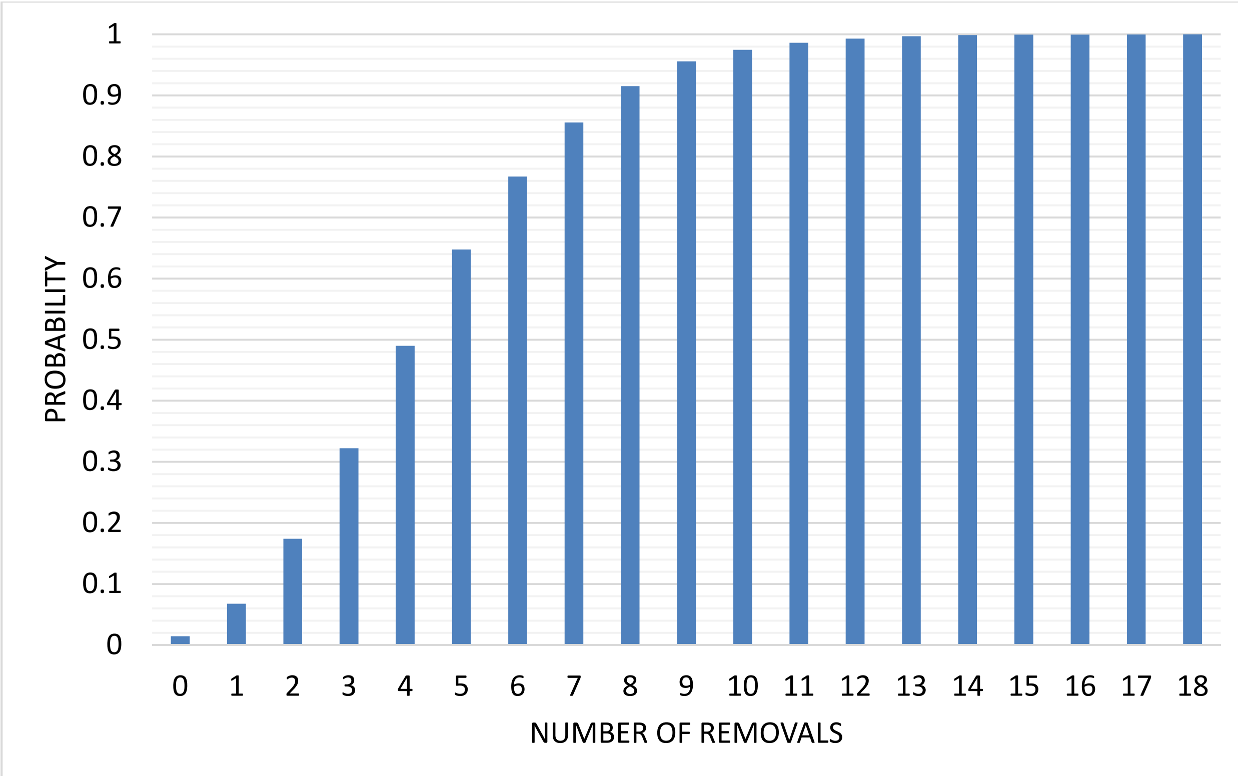

Figure 3-24
Cumulative Probability of In-Service Transformer Removals Next Five Years 230 kV Auto

500 kV Auto Removal Analysis

The following provides the results of the 500 kV Auto transformer group analyzed using the method describe in Chapter 2. More granular groupings, for example by number of phases or MVA, were not feasible because of the lack of data or the reduced number of data points that would result. Table 3-4 shows the number of transformers in-service and removed from service.

Table 3-4
Transformer Group Data 500 kV Auto

Group	In-service	Removed from Service
500 kV Auto	48	21

Age Demographics 500 kV Auto

Figures 3-25 and 3-26 show the age demographics for both in service and removed from service transformer units.

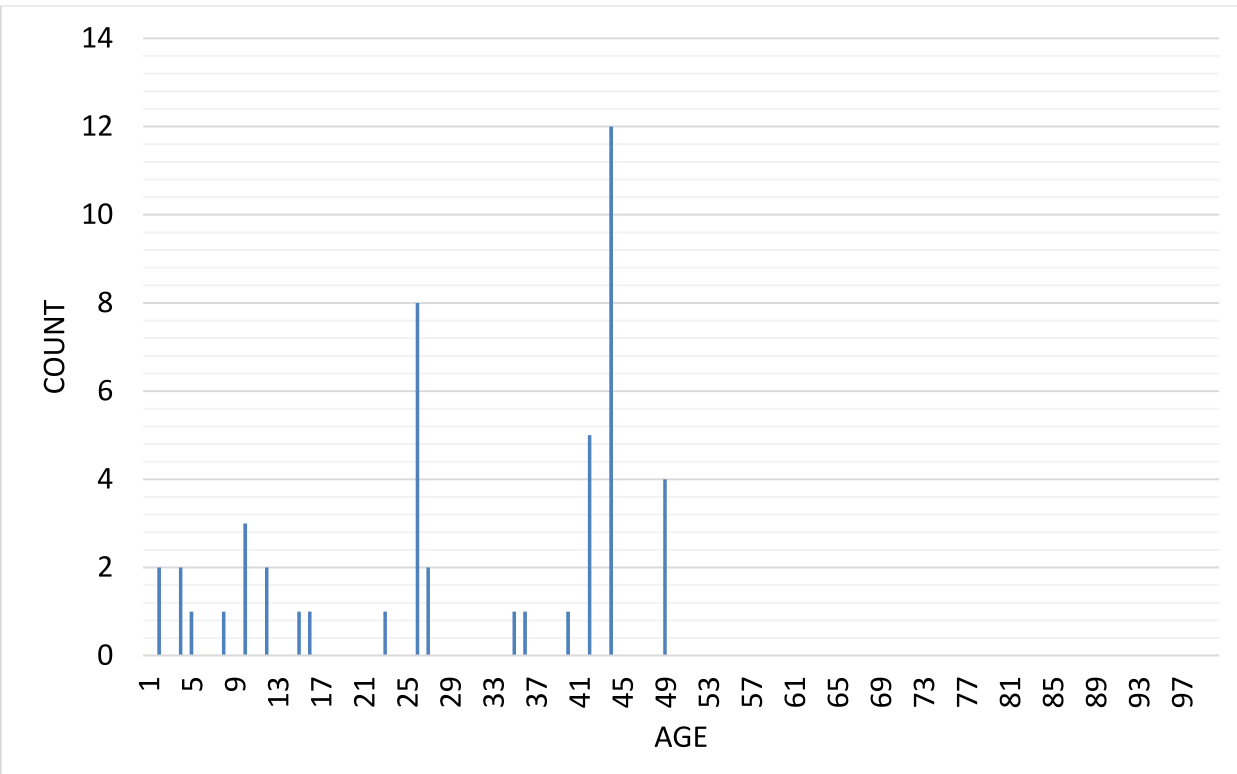

Figure 3-25
Age Demographics In-service 500 kV Auto

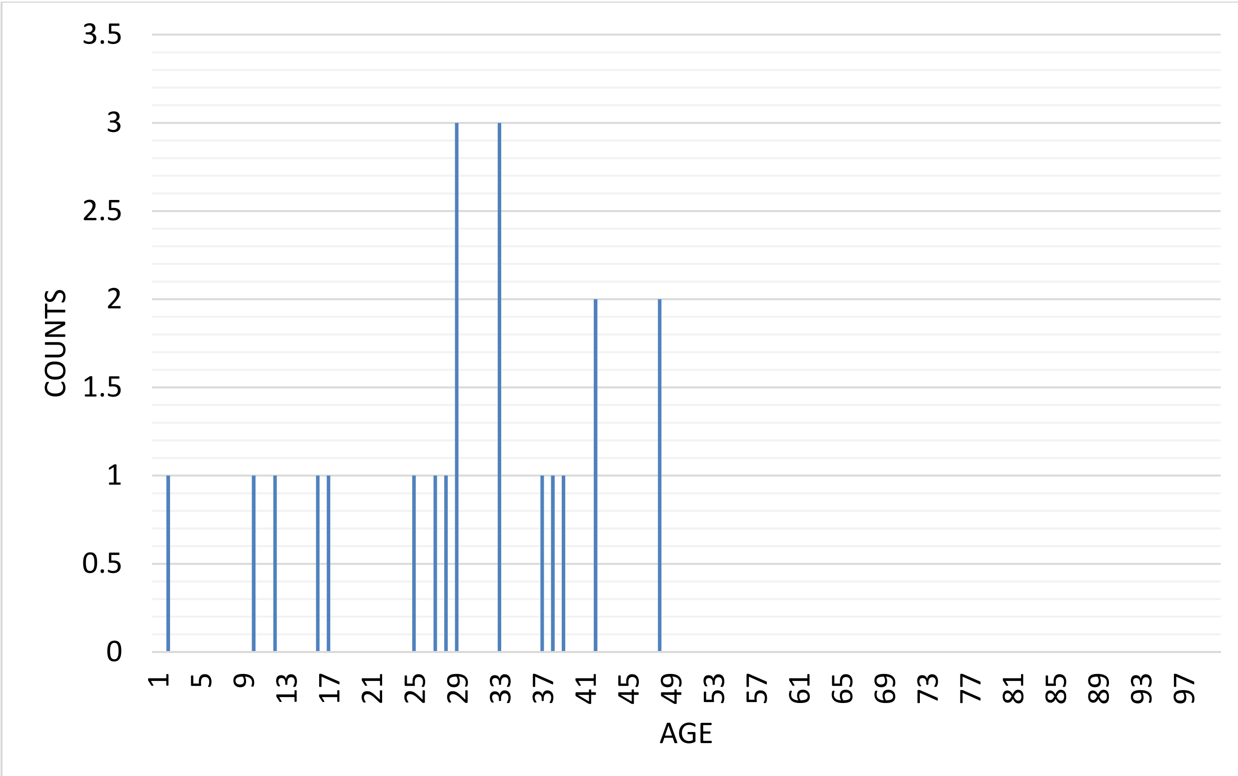

Figure 3-26
Age Demographics Removed From Service 500 kV Auto

Figures 3-27 and 3-28 show the Service Eras and Service Ages of the 500 kV Auto transformer group. The service eras and service ages plots shows the observation period for this transformer group where the observation period began in 1989.

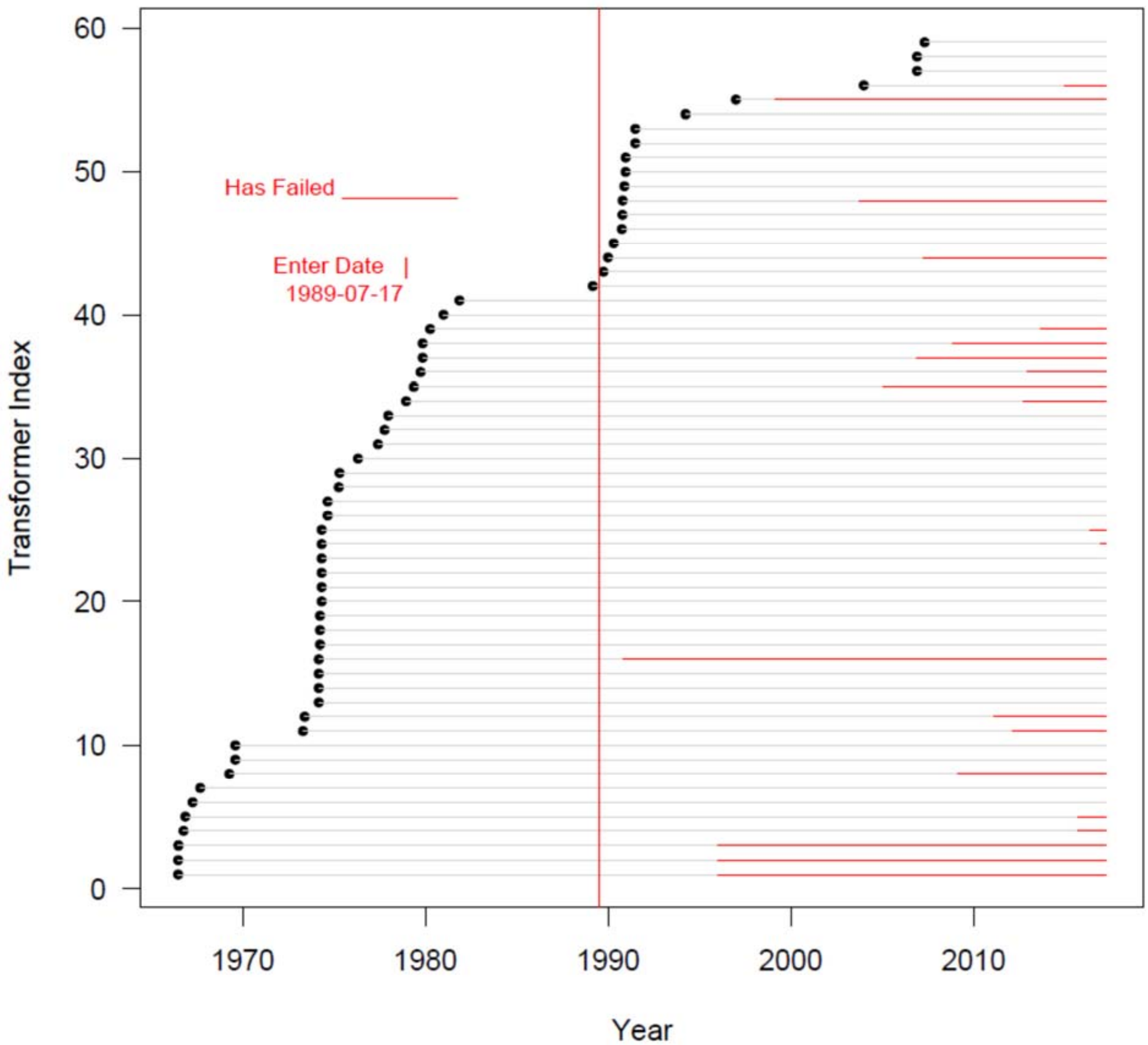

Figure 3-27
Service Eras 500 kV Auto

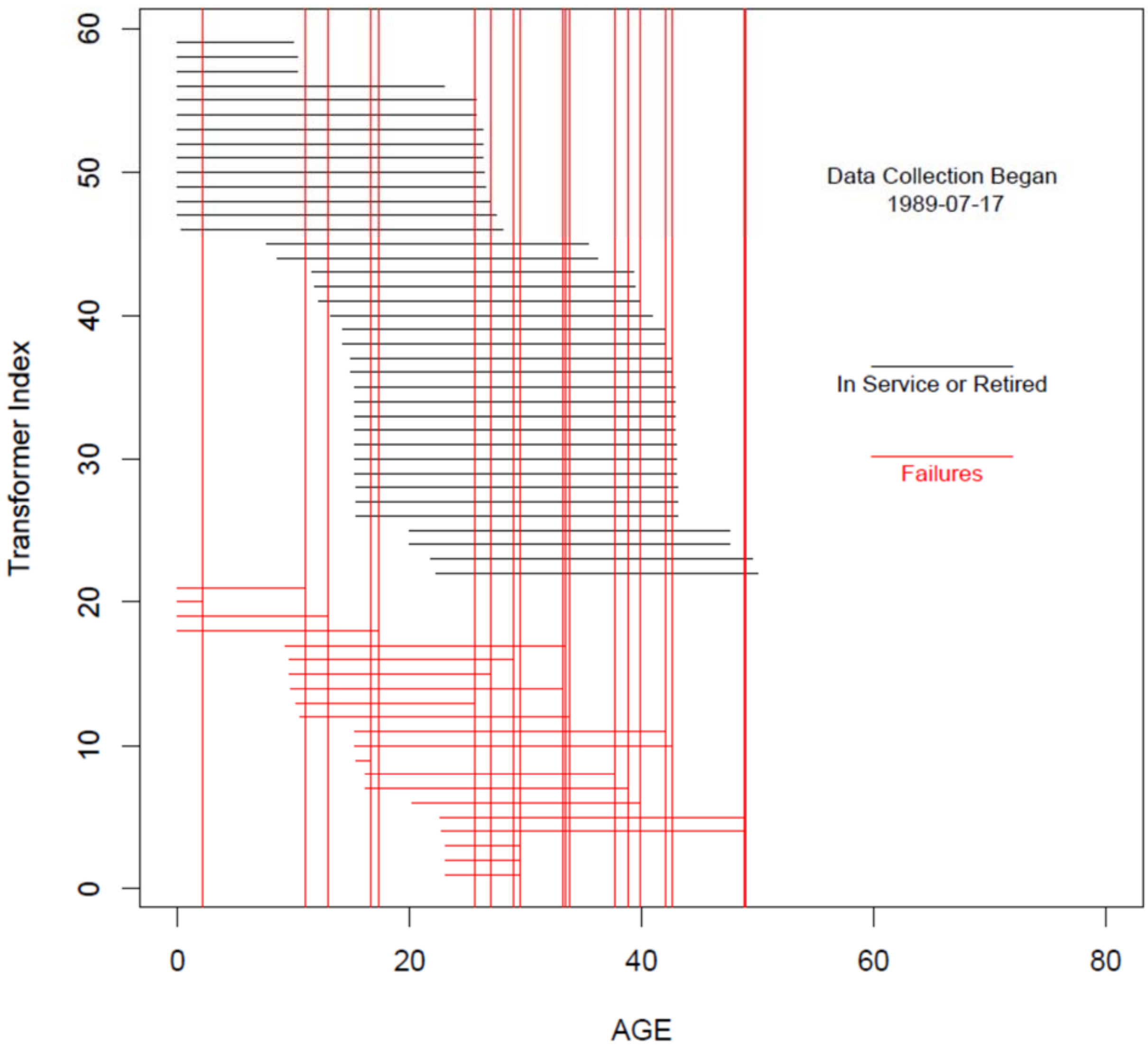

Figure 3-28
Service Ages 500 kV Auto

Removal Hazard Rate 500 kV Auto

Figure 3-29 show the removal rate developed using the in-service and removed from service data provided for the 500 kV Auto transformer. In the figure, probability of a 40 year old transformer being removed in its next year of life ranges from 1.2% to 3.8%. For a 60 year old transformer the probability of being removed in its next year of life ranges from 1.3% to 7%. Note the 95% confidence intervals. The bands become larger above age 50, reflecting the sparse number of recorded removals in these regions.

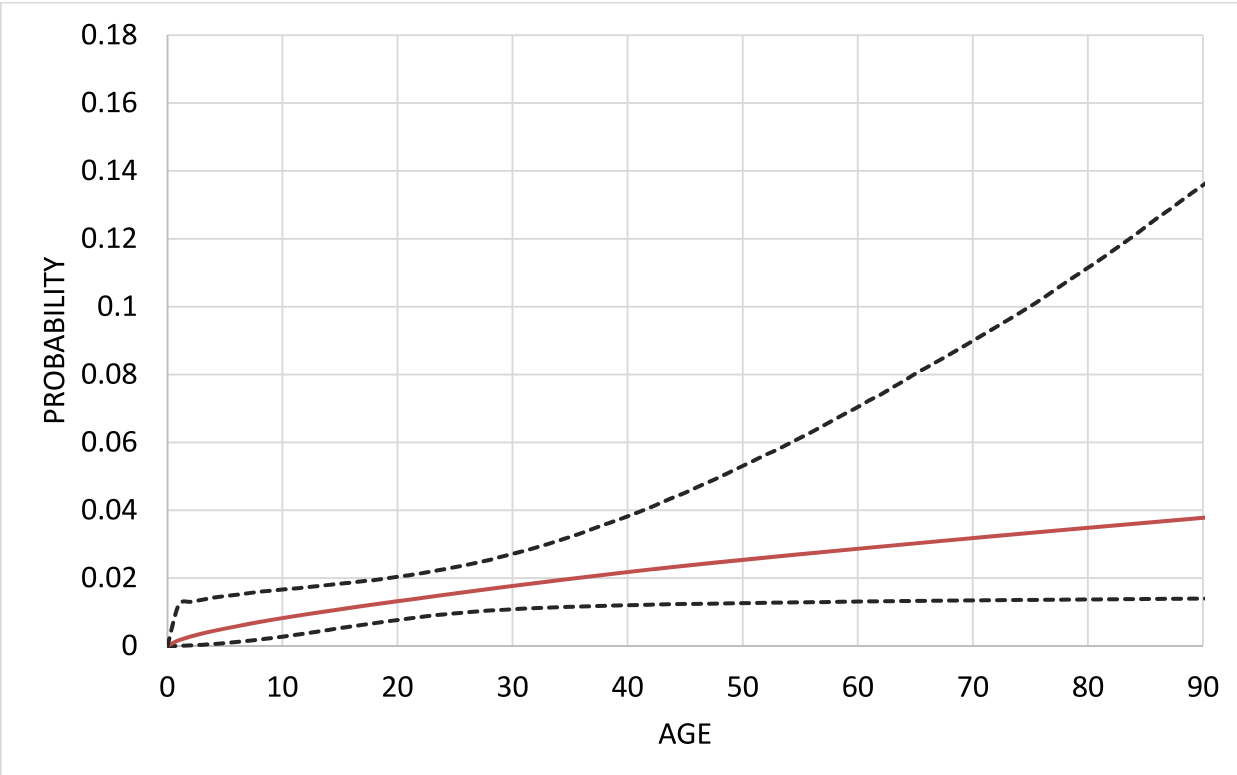

Figure 3-29
Removal Rate 500 kV Auto

Survival Function 500 kV Auto

Figure 3-30 show the survival function developed using the in-service and removed from service data provided for the 500 kV Auto transformer group. In the figure, the mean probability of a 40 year old transformer surviving (not being removed) in its next year of life ranges from 45% to 72%.

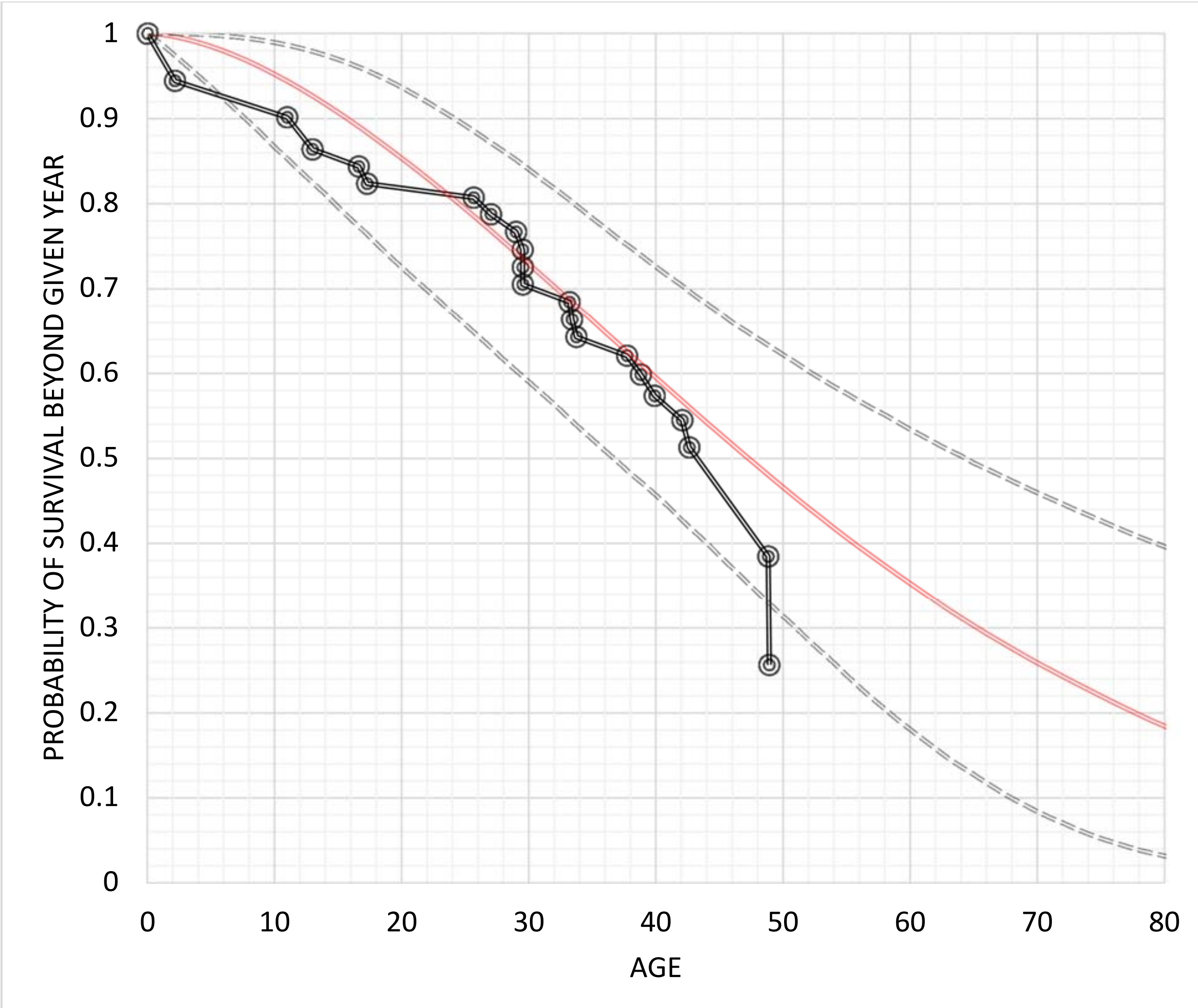

Figure 3-30
Survival Function 500 kV Auto

Forecasting Removals

Figures 3-31 and 3-32 show the predicted number of transformer removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-31. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 3 removals, we can say that we are 99% certain that the number of transformer removals will be 3 or fewer. Figure 3-32 presents the cumulative results combining each year of the five year period.

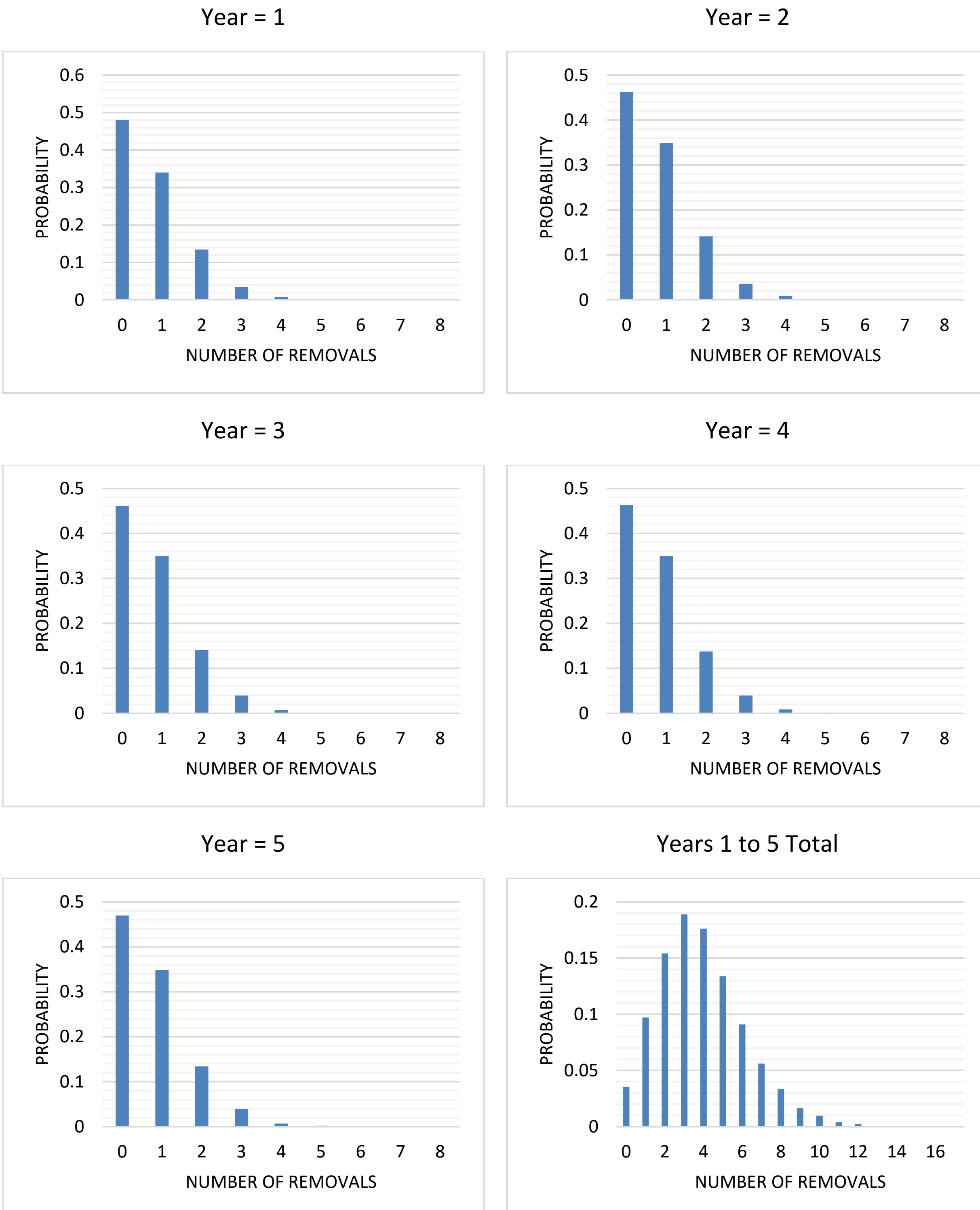

Figure 3-31
Predicted In-Service Transformer Removals for Each of the Next Five Years 500 kV Auto

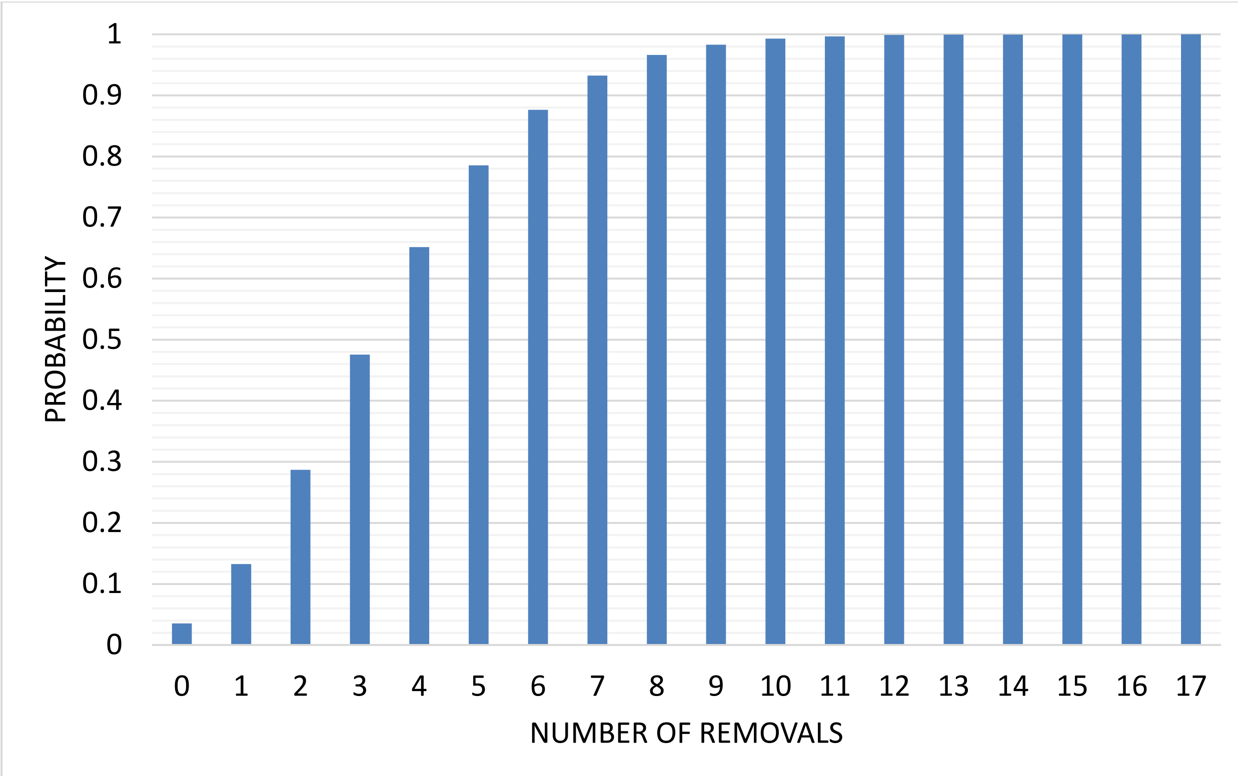

Figure 3-32
Cumulative Probability of In-Service Transformer Removals Next Five Years 500 kV Auto

500 kV Auto 250 MVA Single Phase Removal Analysis

The following provides the results of the 500 kV Auto 250 MVA Single Phase transformer group analyzed using the method describe in Chapter 2. Table 3-5 shows the number of transformers in-service and removed from service.

Table 3-5
Transformer Group Data 500 kV Auto 250 MVA Single Phase

Group	In-service	Removed from Service
500 kV Auto 250 MVA Single Phase	12	8

Age Demographics 500 kV Auto 250 MVA Single Phase

Figures 3-33 and 3-34 show the age demographics for both in service and removed from service transformer units.

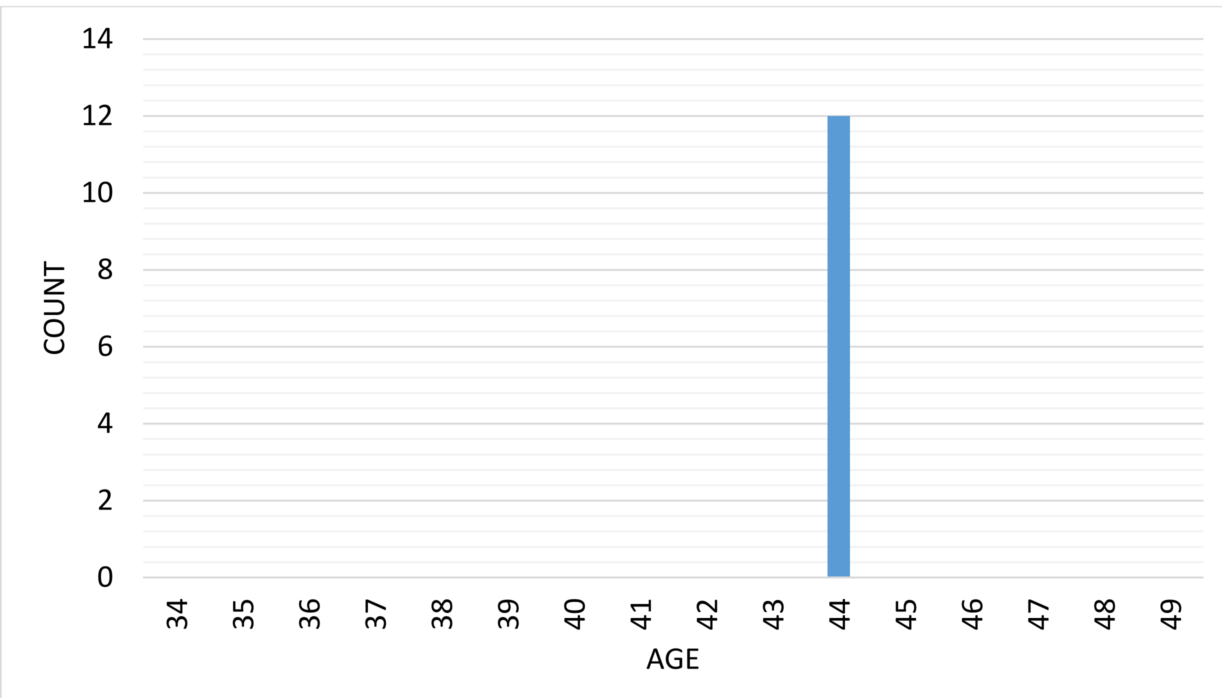

Figure 3-33
Age Demographics In-service 500 kV Auto 250 MVA Single Phase

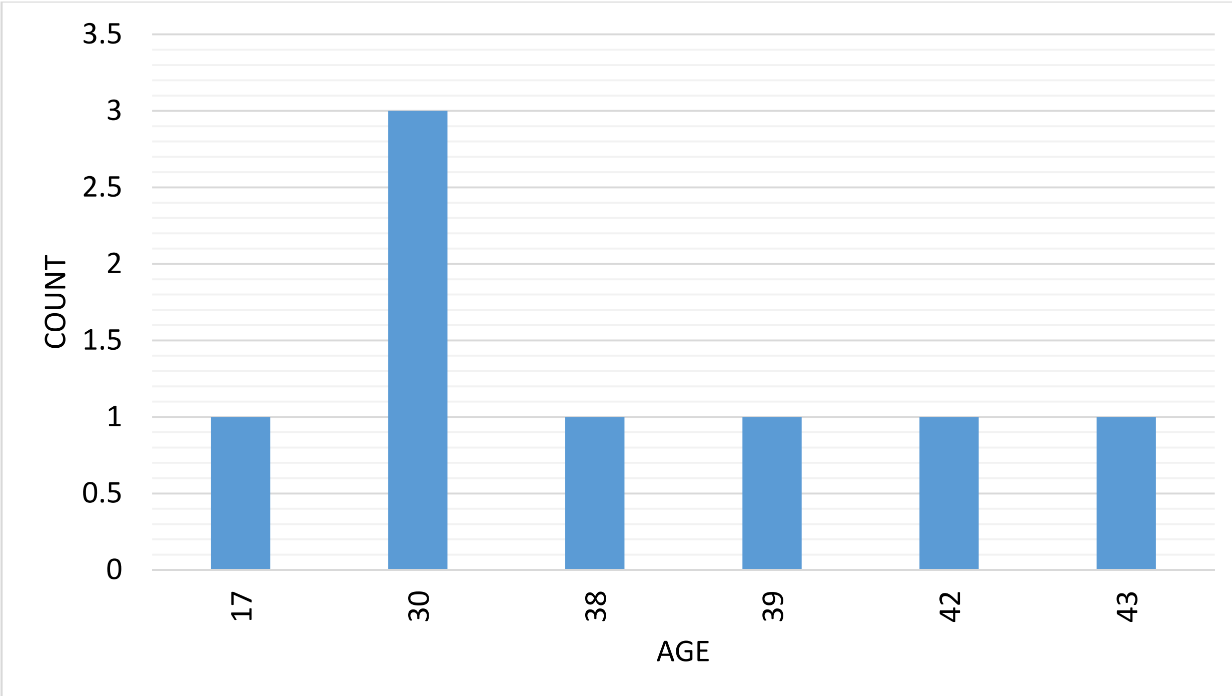

Figure 3-34
Age Demographics Removed From Service 500 kV Auto 250 MVA Single Phase

Figures 3-35 and 3-36 show the Service Eras and Service Ages of the 500 kV Auto 250 MVA Single Phase transformer group. The service eras and service ages plots shows the observation period for this transformer group where the observation period began in 1987.

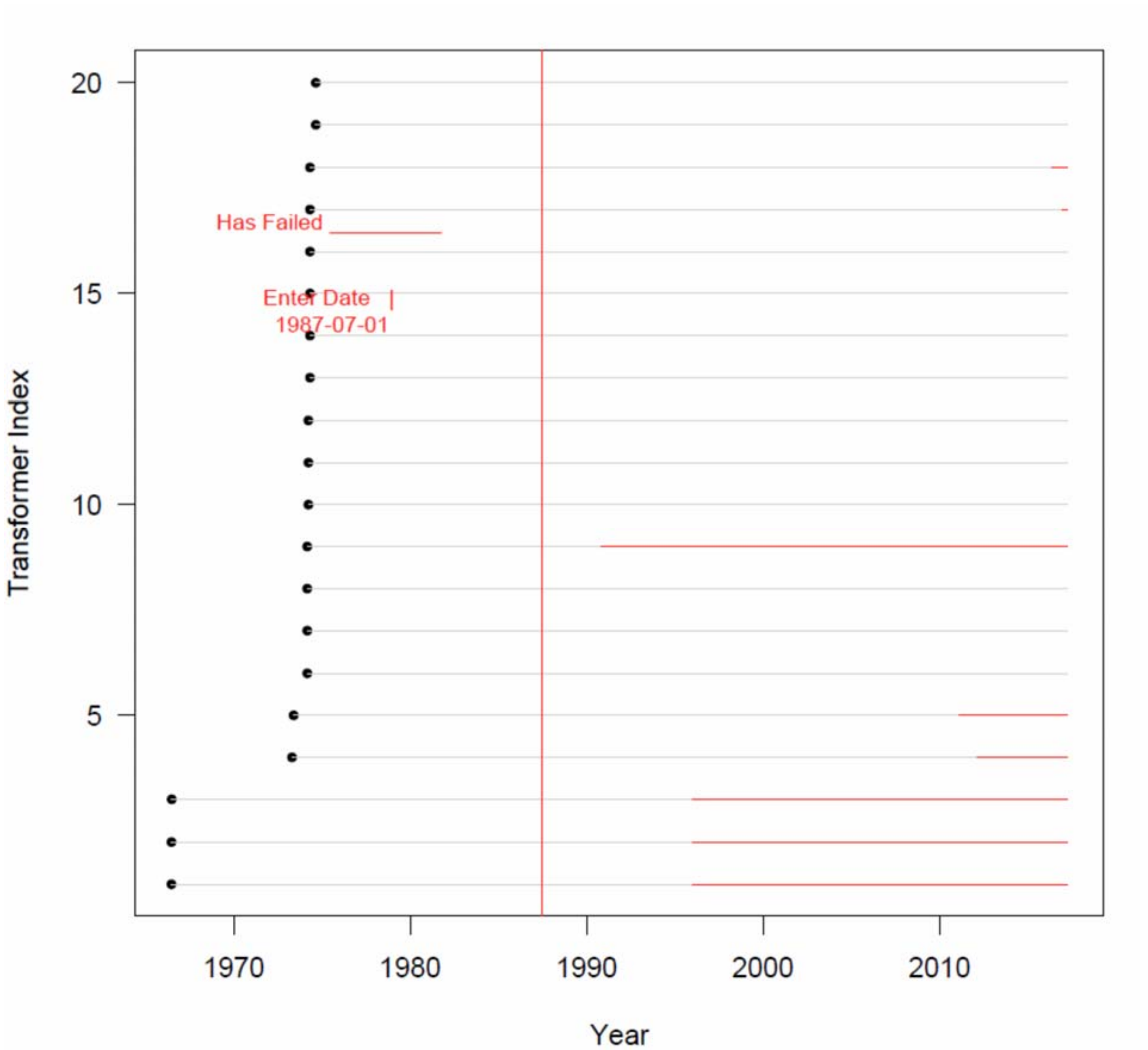

Figure 3-35
Service Eras 500 kV Auto 250 MVA Single Phase

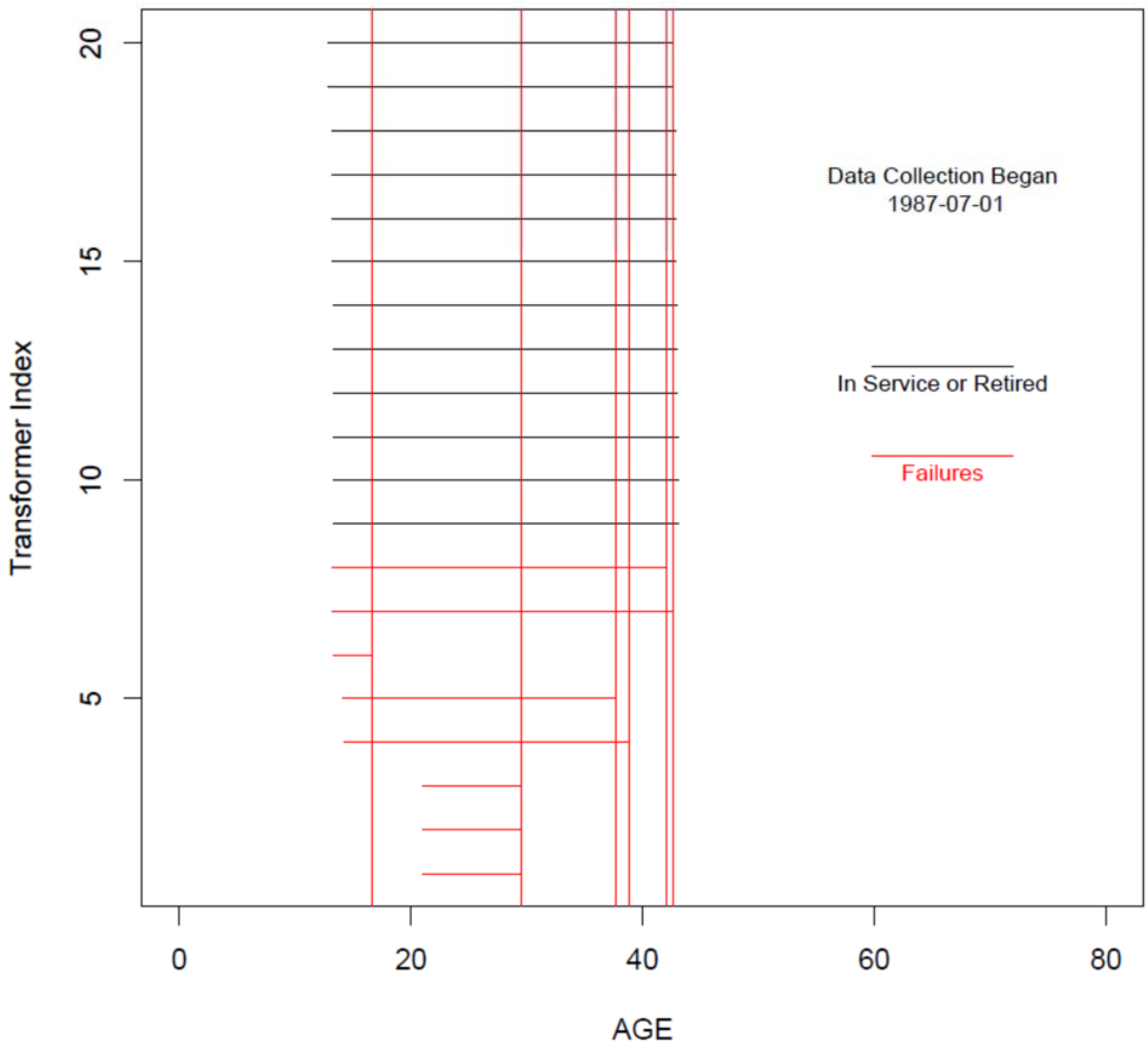

Figure 3-36
Service Ages 500 kV Auto 250 MVA Single Phase

Removal Hazard Rate 500 kV Auto 250 MVA Single Phase

Figure 3-37 shows the removal rate developed using the in-service and removed from service data provided for the 500 kV Auto 250 MVA Single Phase transformer. In the figure, probability of a 40 year old transformer being removed in its next year of life ranges from 0.8% to 5.2%. For a 60 year old transformer the probability of being removed in its next year of life ranges from 0.9% to 14.6%. Note the 95% confidence intervals. The bands become larger above age 40, reflecting the sparse number of recorded removals in these regions.

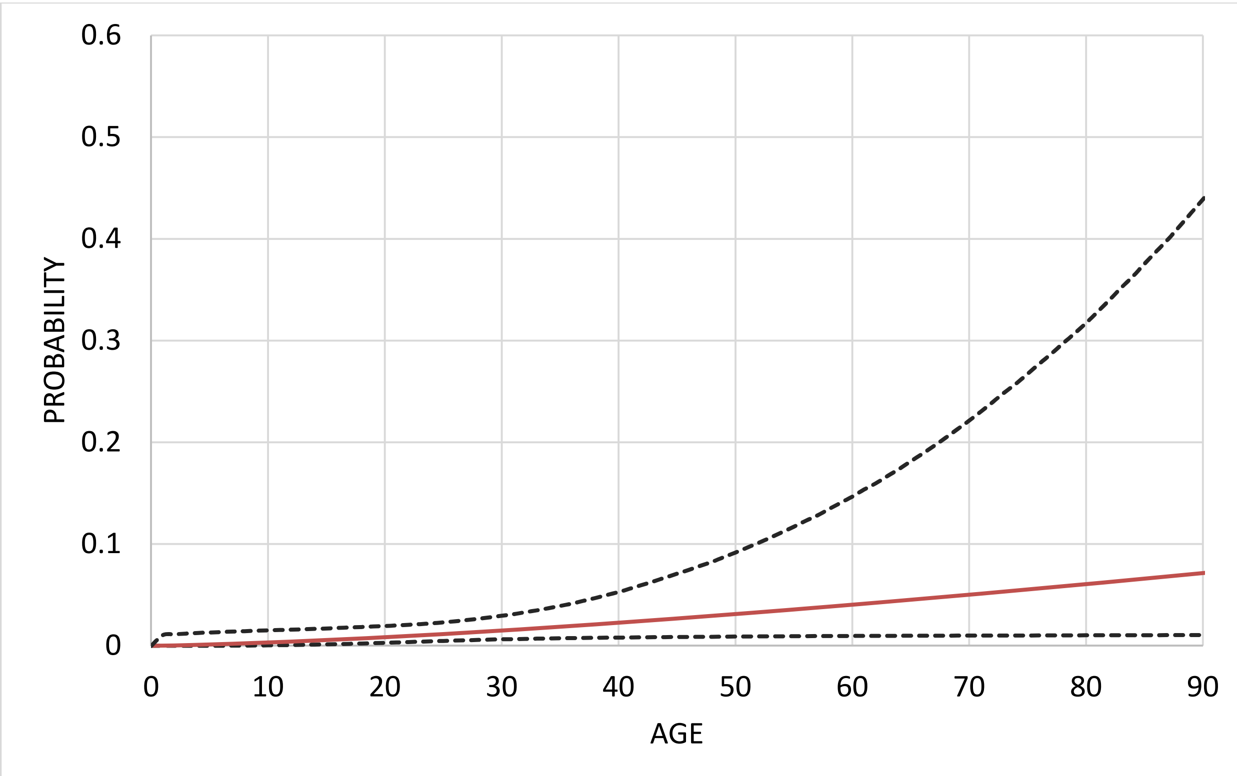

Figure 3-37
Removal Rate 500 kV Auto 250 MVA Single Phase

500 kV Auto 750 MVA Three Phase Removal Analysis

The following provides the results of the 500 kV Auto 750 MVA Three Phase transformer group analyzed using the method describe in Chapter 2. Table 3-6 shows the number of transformers in-service and removed from service.

Table 3-6
Transformer Group Data 500 kV Auto 750 MVA Three Phase

Group	In-service	Removed from Service
500 kV Auto 750 MVA Three Phase	32	10

Age Demographics 500 kV Auto 750 MVA Three Phase

Figures 3-38 and 3-39 show the age demographics for both in service and removed from service transformer units.

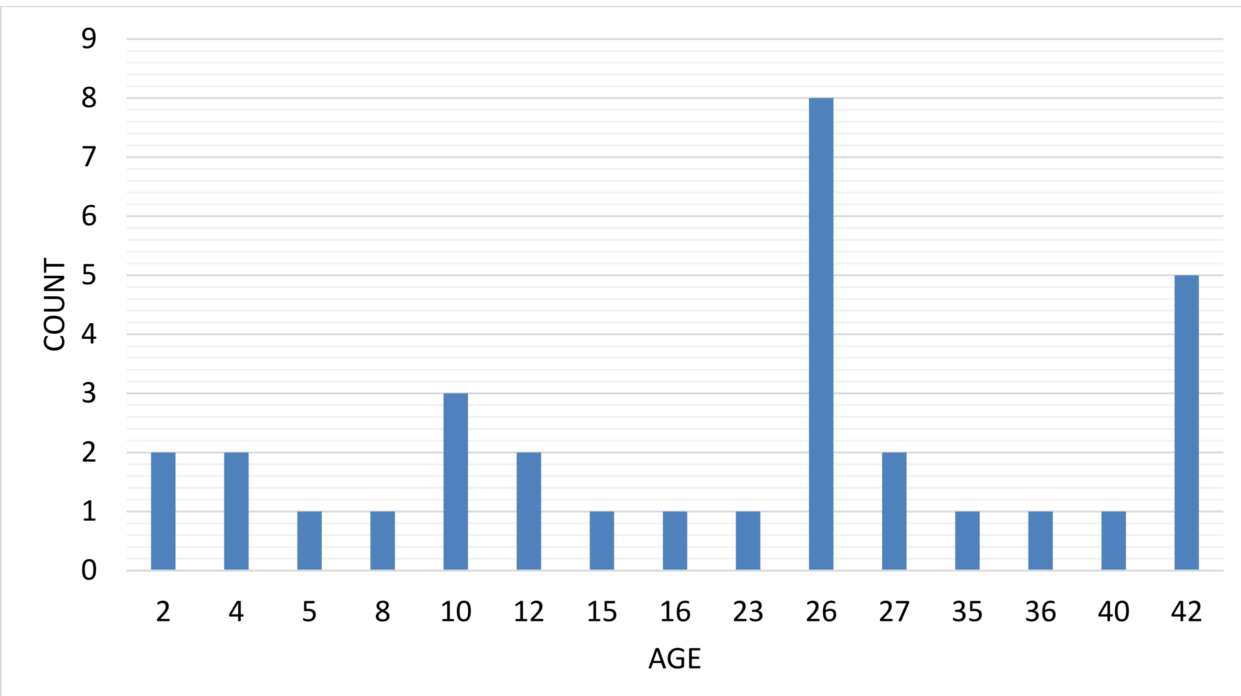

Figure 3-38
Age Demographics In-service 500 kV Auto 750 MVA Three Phase

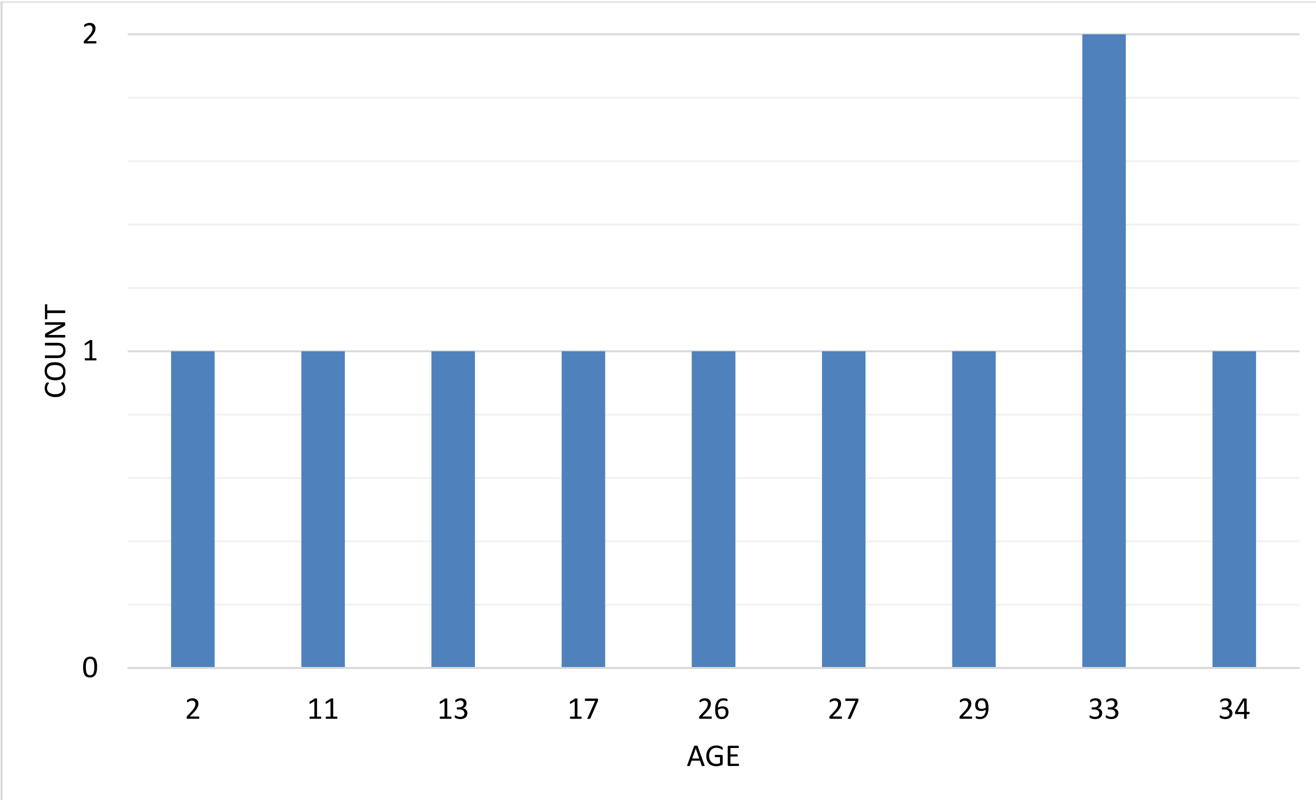

Figure 3-39
Age Demographics Removed From Service 500 kV Auto 750 MVA Three Phase

Figures 3-40 and 3-41 show the Service Eras and Service Ages of the 500 kV Auto 750 MVA Three Phase transformer group. The service eras and service ages plots shows the observation period for this transformer group where the observation period began in 1997.

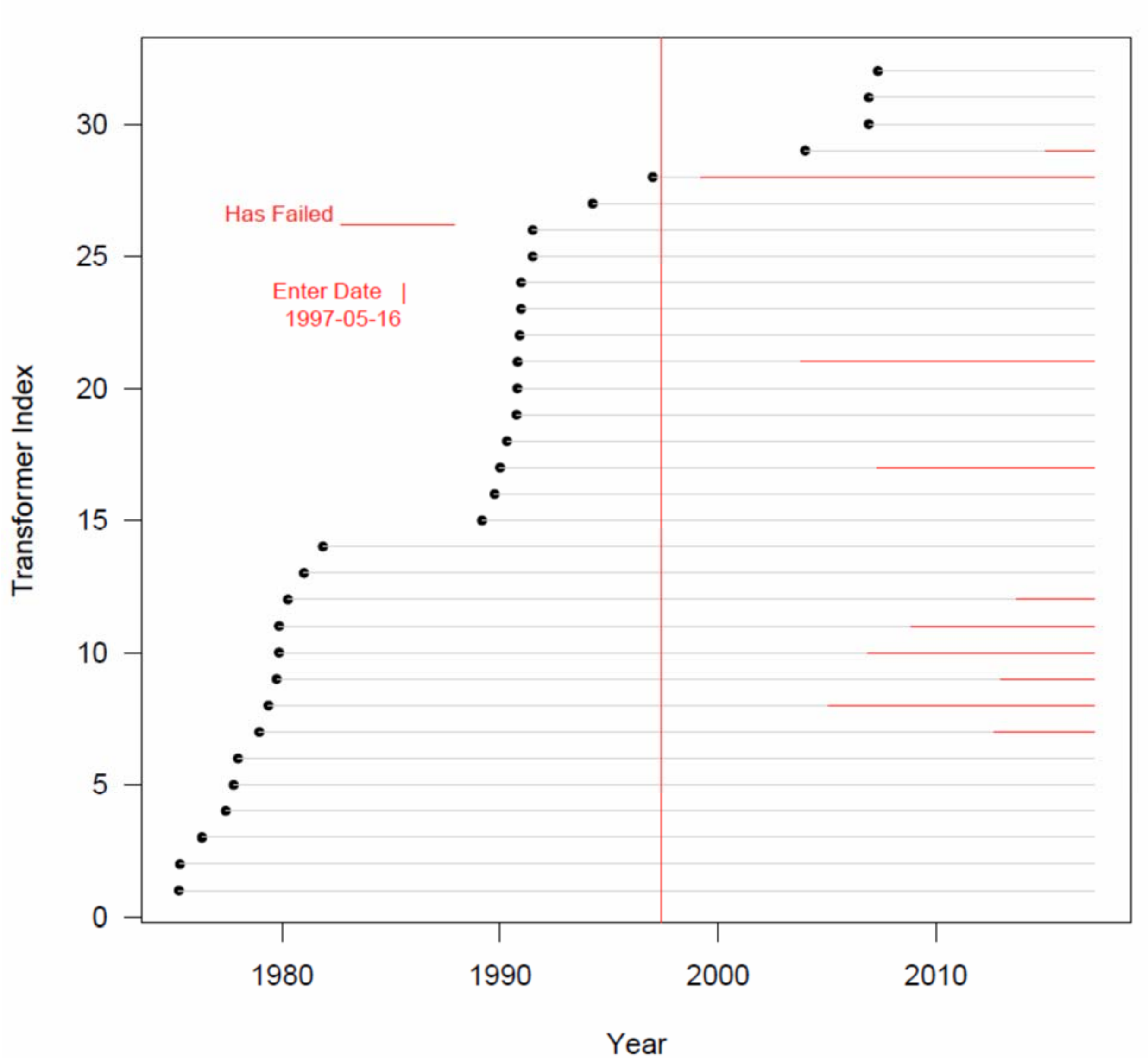

Figure 3-40
Service Eras 500 kV Auto 750 MVA Three Phase

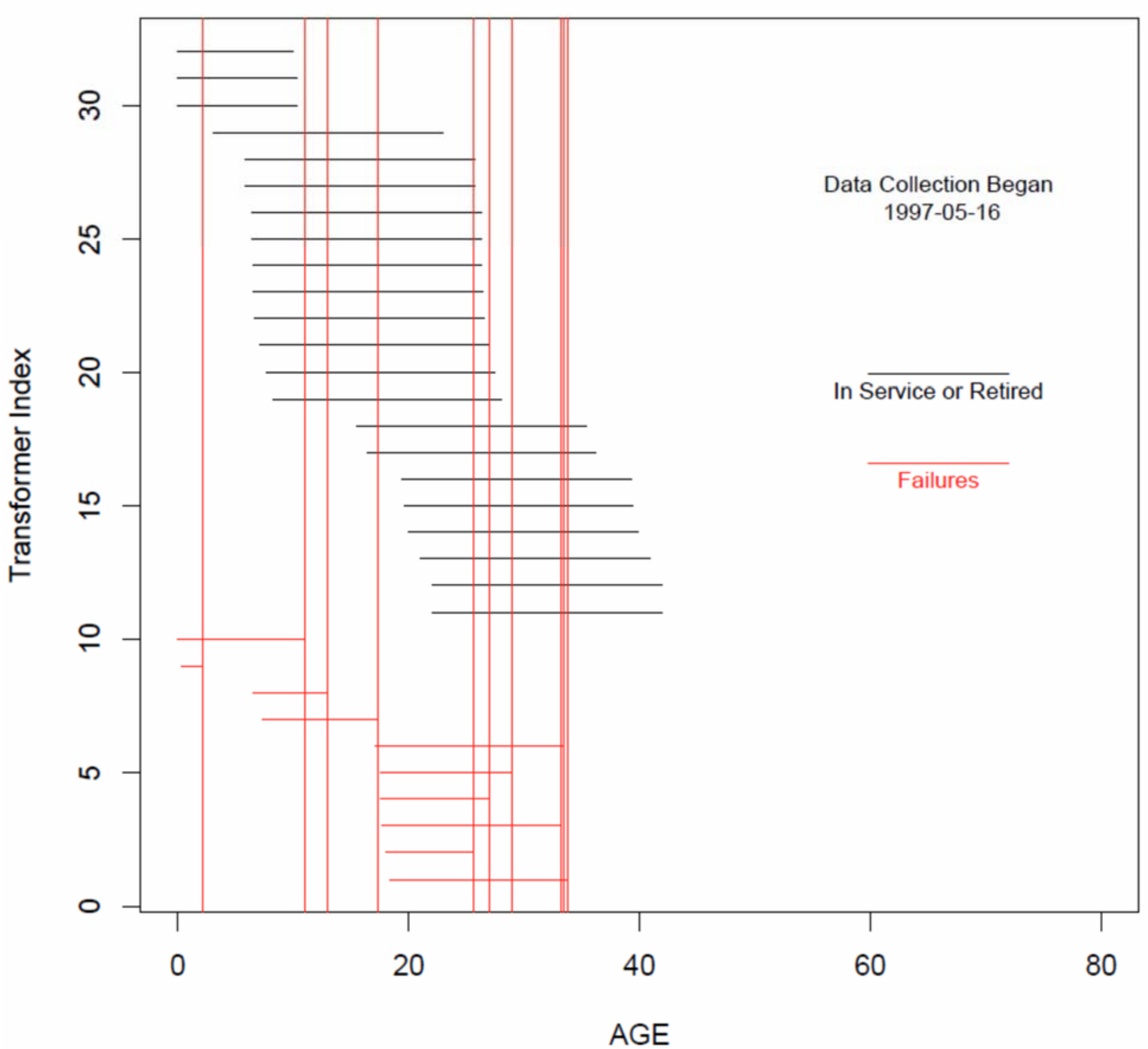

Figure 3-41
Service Ages 500 kV Auto 750 MVA Three Phase

Removal Hazard Rate 500 kV Auto 750 MVA Three Phase

Figure 3-42 shows the removal rate developed using the in-service and removed from service data provided for the 500 kV Auto 750 MVA Three Phase transformer. In the figure, probability of a 40 year old transformer being removed in its next year of life ranges from 0.9% to 6.7%. For a 60 year old transformer the probability of being removed in its next year of life ranges from 1% to 14.9%. Note the 95% confidence intervals. The bands become larger above age 30, reflecting the sparse number of recorded removals in these regions.

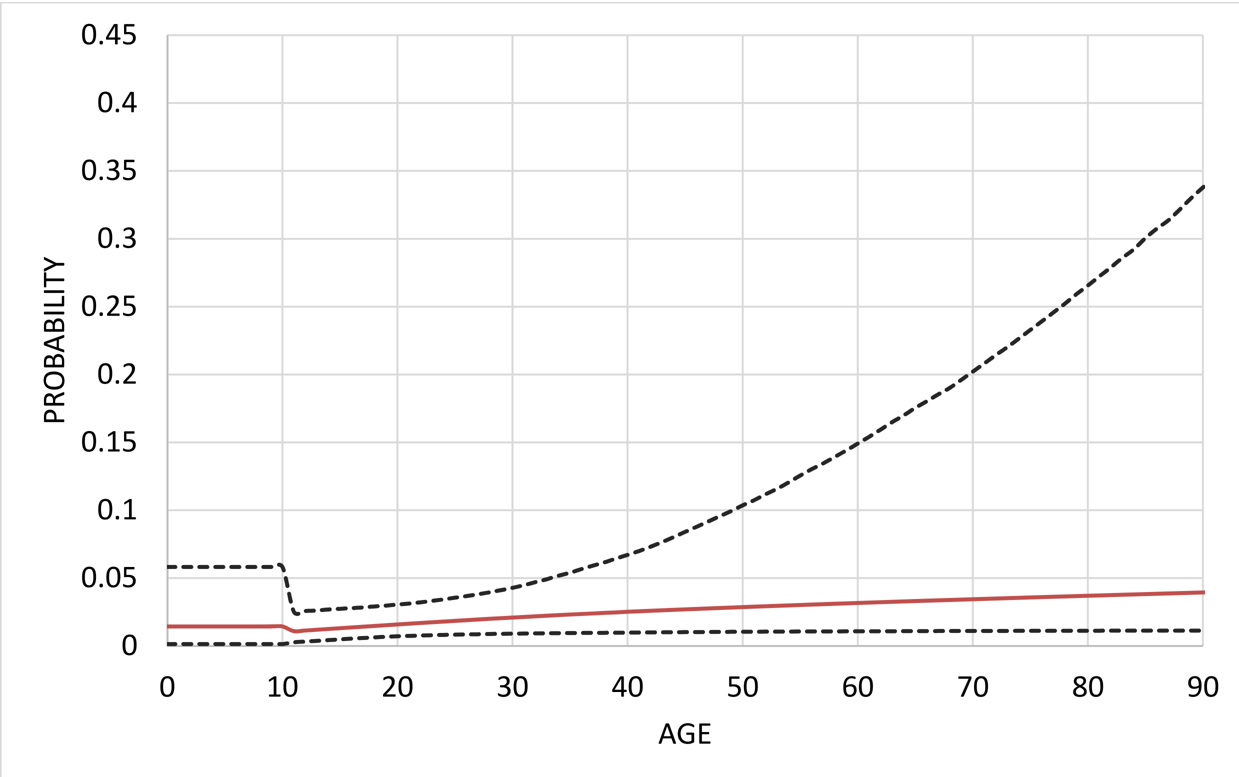

Figure 3-42
Removal Rate 500 kV Auto 750 MVA Three Phase

Removal Hazard Rate Comparison 500 kV Auto 750 MVA Three Phase and 500 kV Auto 250 MVA Single Phase

It can be seen in Figure 3-43 that no useful distinction can be made between the two derived removal hazard rates using the data provided.

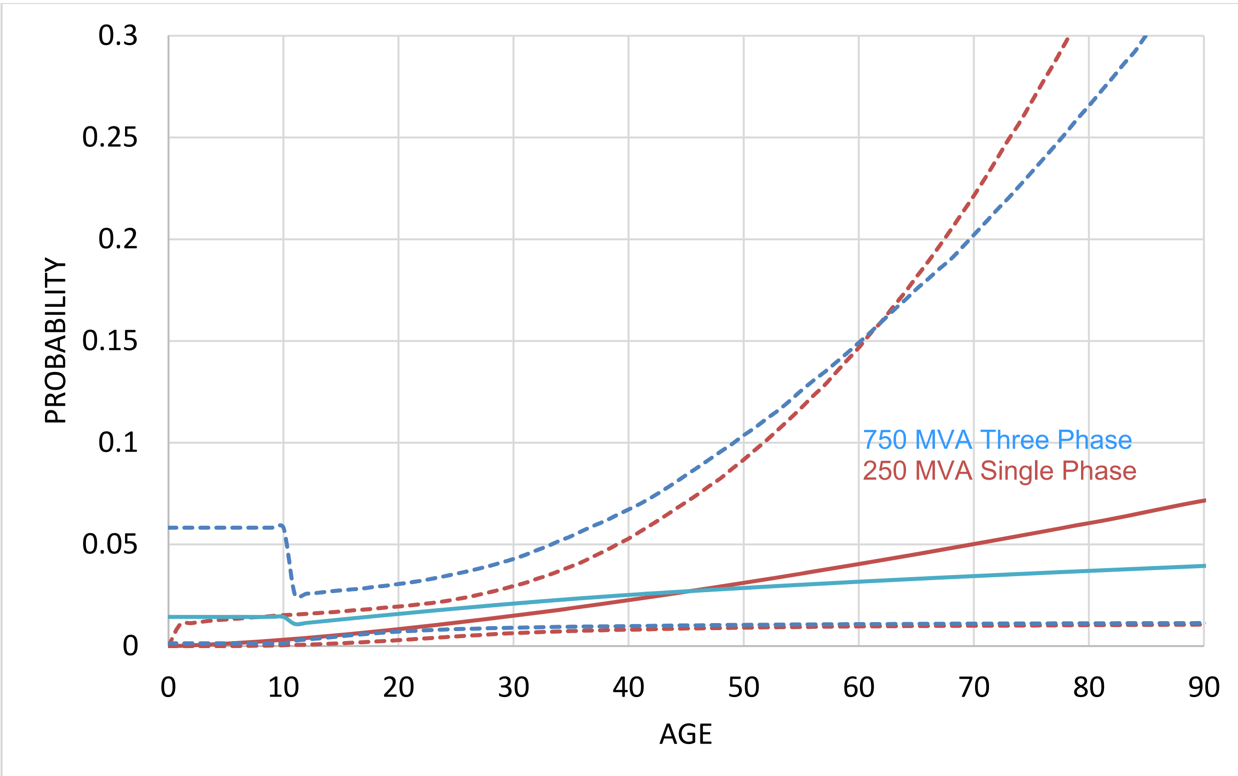

Figure 3-43
Removal Rate Comparison 500 kV Auto 750 MVA Three Phase and 500 kV Auto 250 MVA Single Phase

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Derivation of Circuit Breaker Hazard Functions

Derivation of Circuit Breaker Hazard Functions

Technical Update, February 2018

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Electric Power Research Institute (EPRI)
1300 West W.T. Harris Blvd.
Charlotte, NC28262

Principal Investigator
B. Desai
J. Bolano

Coplanar Consulting, LLC
893 Princess Drive
Yardley, PA 19067

Principal Investigator
M. Lebow

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EXECUTIVE SUMMARY

A key goal of asset management is to base decisions on an equipment fleet's mean life expectancy. Insights on the fleet mean life expectancy may be derived from careful analysis of historical replacement data. This report describes EPRI work to model and develop circuit breaker removal hazard rates from historical replacement records and apply them to forecast the number of circuit breakers expected to require replacement based on past replacement practices.

EPRI has developed a methodology using advanced statistical techniques for analyzing circuit breaker historical performance and applied it to the Hydro One Networks Inc. transmission circuit breaker fleet. Hydro One Networks Inc. provided in-service and removed from service data for their circuit breaker fleet. Using this data, EPRI developed models for removal rates of circuit breakers as a function of their age. The models along with information about the current fleet were used to project the number of circuit breakers expected to be removed from service over the next five year period assuming past practices are continued to be followed. The results are provided in circuit breaker groups by voltage rating and interrupting mediums.

Keywords
Circuit Breakers
Asset Management
Industry-wide Database
Fleet Management

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1
SUPPLIEDCIRCUIT BREAKER DATA

Data Received

Hydro One Networks Inc. (Hydro One) provided the following data as shown in Table 1-1. The circuit breaker fleet has been grouped by voltage rating in kV and interrupting mediums.

Table 1-1
Circuit breaker Group Data

Group	In-service	Removed from Service
13 – 27 kV Air Blast	37	21
13 kV Air Magnetic	251	72
13 – 27 kV Gas	911	163
13 – 27 kV Oil	835	357
13 – 27 kV Vacuum	344	30
44 kV Gas	363	40
44 kV Oil	443	77
115 kV Gas	308	33
115 kV Oil	227	255
230 kV Gas	417	28
230 kV Oil	167	123
230 kV Air Blast	100	99
500 kV Gas	100	4
500 kV Air Blast	47	13

In-service Data

The in-service data provided by Hydro One consists of 4450 Circuit Breakers as of third quarter 2017. The data included the following fields:

- Substation
- Position
- Serial Number
- Manufacturer
- Voltage Rating
- Date Installed
- Age
- Interrupting Medium

Figure 1-1 shows the age demographics of the in-service circuit breaker fleet as of third quarter 2017.

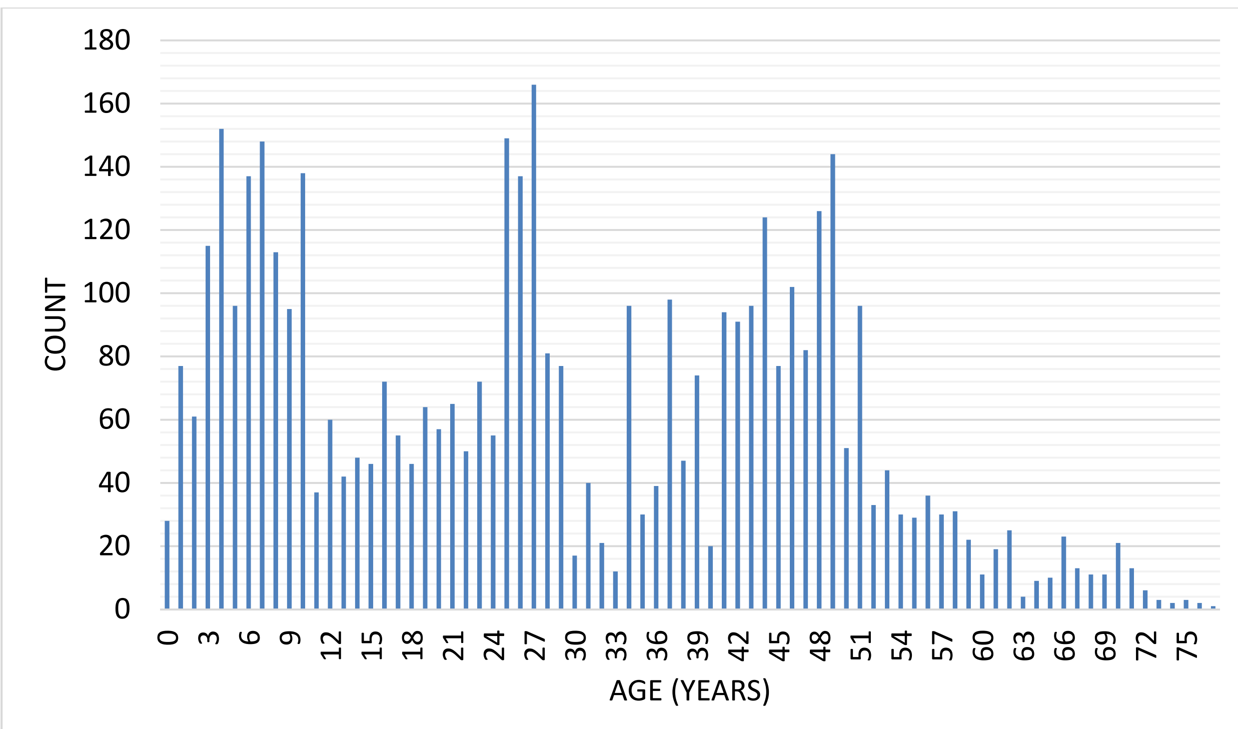

Figure 1-1
In-service Circuit Breaker Age Demographics

Removed from Service Data

The removed from service data provided by Hydro One consists of 1218circuit breakers as of third quarter 2017. No reason for removal was provided. The data included the following fields:

- Substation
- Position
- Serial Number
- Manufacturer
- Voltage Rating
- Date Installed
- Date Removed
- Age
- Interrupting Medium

Figure 1-2 shows the age demographics of the removed from service circuit breakers from the period of 1981 to third quarter 2017.

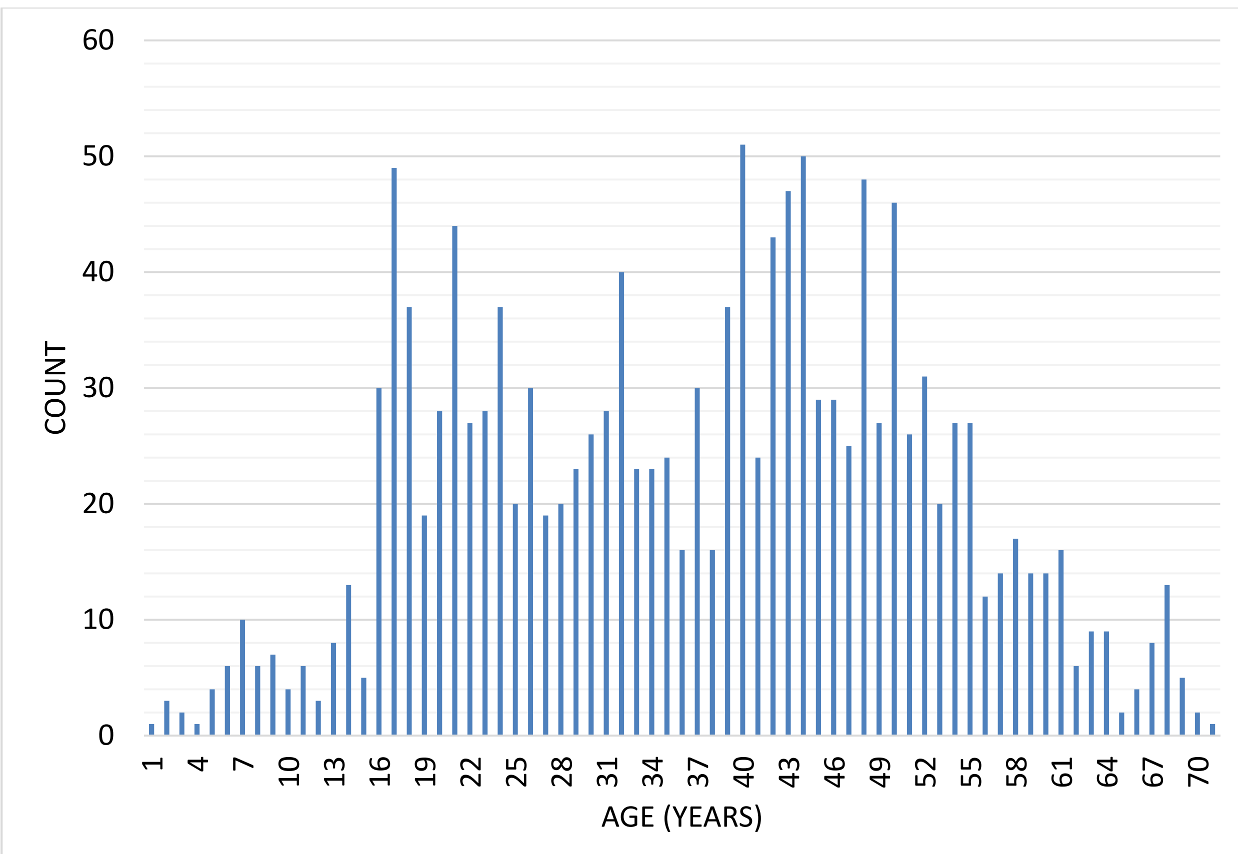

Figure 1-2
Removed from Service Circuit Breaker Age Demographics

2
REMOVAL RATE MODELING

Modeling

EPRI has developed a proven analytic methodology for analyzing circuit breaker event data. The methodology has been demonstrated with a number of utilities' datasets. The modeling methodology assumes a Weibull hazard function for the underlying data described by two parameters, shape and scale. The problem is then to develop the most likely shape and scale values based on the empirical data. A Bayesian approach is utilized.

Analysis began with a "prior distribution" based on the results of EPRI observations of previous utilities circuit breaker data set of in-service and failures. In the Bayesian paradigm, this current knowledge about the model parameters is expressed by placing a probability distribution on the parameters, the prior distribution. As new data, in this case removal observations, becomes available, the information contained regarding the model parameters is expressed in a likelihood, which is proportional to the distribution of the observed data given the model parameters. This information (from removal data) is then combined with the prior distribution to produce a new, upgraded probability distribution formally called the posterior distribution or updated distribution. The calculation involves multidimensional integration of complicated functions and is computationally intense and a Markov Chain Monte Carlo, MCMC, method was used.

The process will be described using the 44 kV oil circuit breaker data as an example. Figure 2-1 is a bivariate plot showing the calculation results for removal for the 44 kV oil circuit breaker population. The blue dots represent a random sample of 9,600 pairs from the updated distribution of shape and scale given the information from the data provide Hydro One. The red ellipse contains the central 95% of the distribution, that is, where most (95%) of the pairs are located. The red dot is the mean of the upgraded Weibull parameter knowledge, the expected shape and scale values. From these upgraded shape and scale parameters removal predictions for currently in-service circuit breakers can be made.

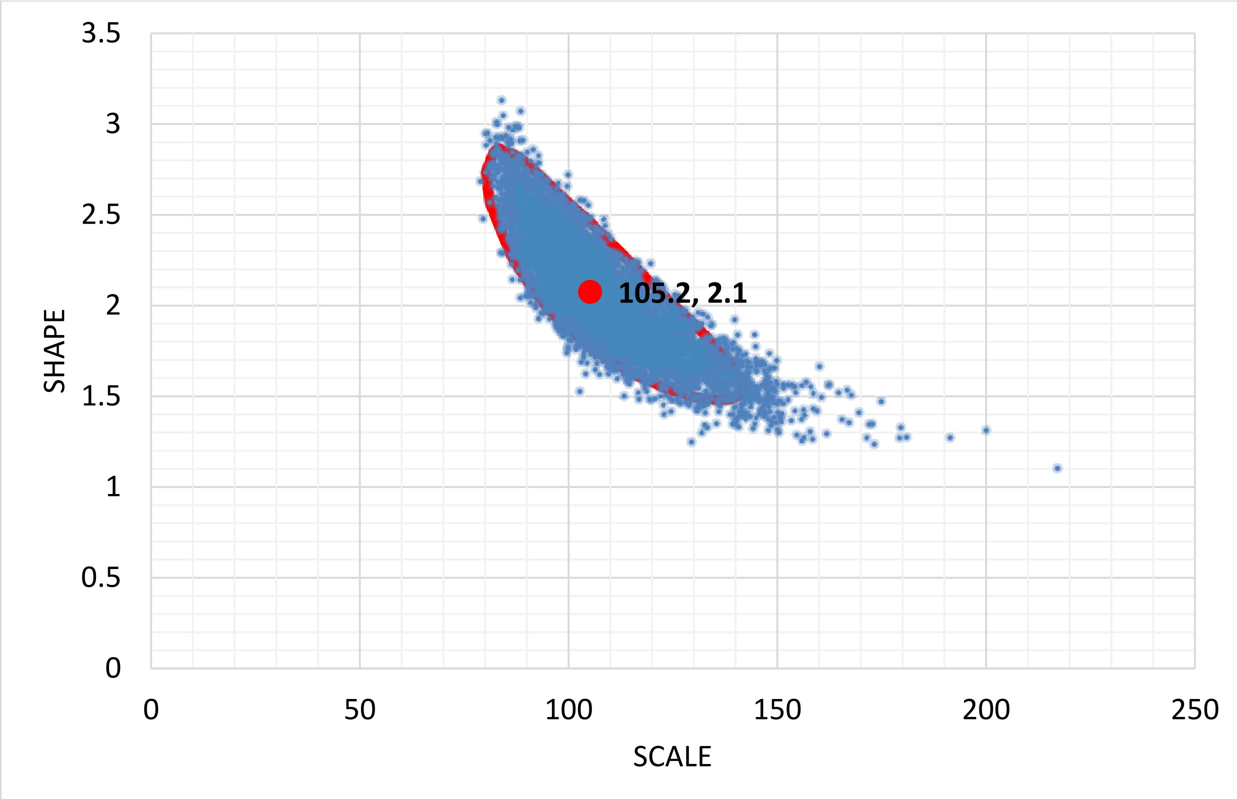

Figure 2-1
Bayesian Result44 kV Oil Circuit breakers

Fitting the data to the Model

The removal rate model is verified by comparing the sample cumulative hazard function calculated from the actual event data (the removals) against the cumulative hazard functions created from the Weibull model. There are cumulative hazard functions for each MCMC observation. For each age from 0 to 100, we calculate the median cumulative hazard rate and the corresponding 95% credibility interval. This calculation provides the median cumulative hazard rate (solid red line) for the model shown in Figure 2-2. The dashed red lines give the 95% credibility interval for these calculations. The black line is the actual event data cumulative hazard function calculated using the Nelson-Aalen technique. The Nelson-Aalen technique is an established statistical technique for developing a non-parametric estimate of the cumulative hazard function based on the observed data.

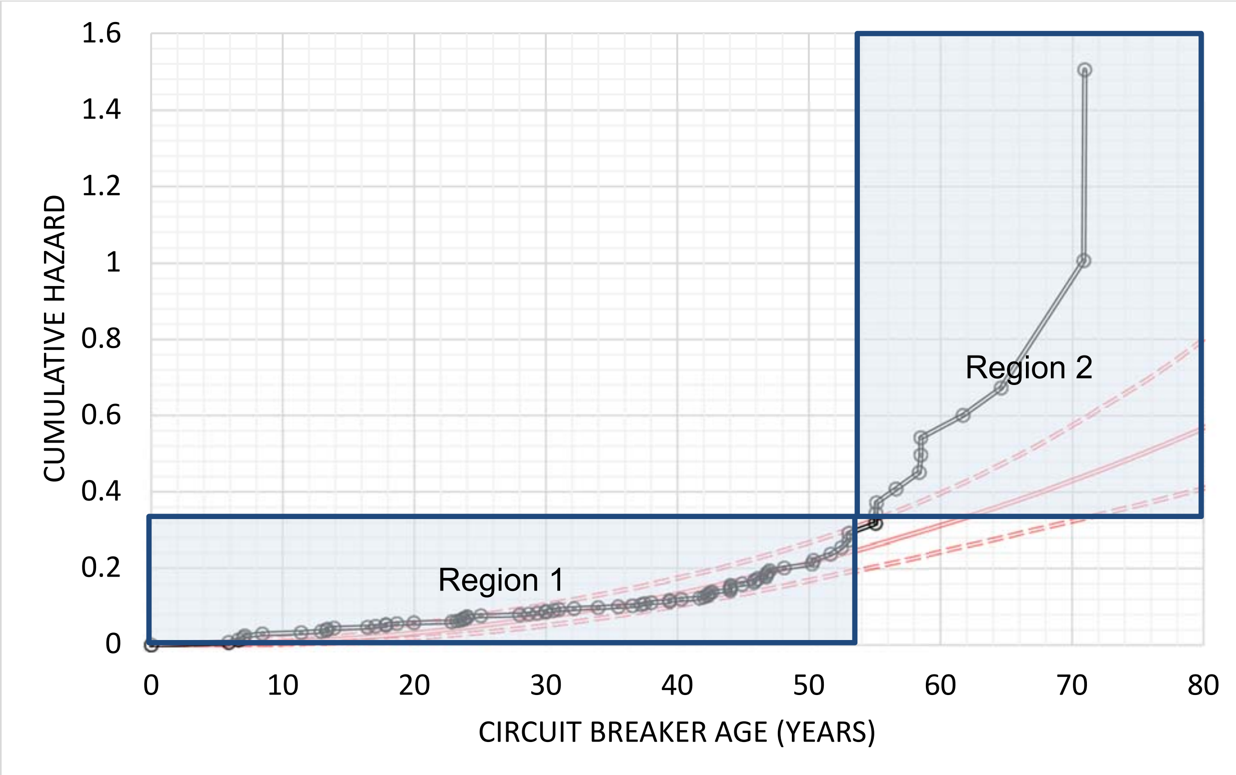

Figure 2-2
Comparison of Model and Sample Cumulative Hazard Functions44kV Oil Circuit breakers

Figure 2-2 for the 44 kV oil circuit breaker group show two regions with different levels of agreement between the red and black lines. A good Weibull model fit for most of the life (Region 1) and a much steeper replacement rate (black line) than provided by the Weibull model in later life (Region 2). However, younger power circuit breakers are rarely replaced except for failure. Therefore, Region 1 may be a reasonable model for the failure hazard rate. The transition point between the two regions could indicate the following:

- The onset of a failure process that is more dominant in older units.
- The result of discretionary replacement decisions.
- Some combination of both failure process and discretionary replacement.

Since the reasons for removal are not noted, failures and discretionary replacements cannot be distinguished.

Modeling Assumptions

- The starting data is complete and contains all removals and in-service units for the period within 1982 through third quarter 2017.
- The criteria for removal have been constant over the historical period being analyzed.

- Future criteria for removals will be the same as in the past.
- Any external effects on removal rates (e.g. budget constraints) were constant over the historical period and will be unchanged over the forecast period.
- Underlying wear-out processes will not change.
- It is important to note that the hazard rate function derived is for removals, not failures.

Modeling Results

There are currently 443 circuit breakers in service of various ages in the 44 kV oil group. Based on the age of each individual circuit breaker, the distributions of the number of removals was predicted from a Monte Carlo simulation.

Each of the 9,600 pair results from the analyses results (Figure 2-1) is used in a Monte Carlo simulation to generate the expected number of removals. Each shape and scale pair defines a Weibull distribution. This distribution is applied to each of the in-service circuit breakers and the number of removals are summed for the total population for that particular distribution.

The resulting histogram of the sum of the number of removals recorded in each plot (Figure 2-3) gives the probability distribution of removals. The entire process is then repeated for the next year with each circuit breaker's age incremented by one.

Figure 2-3 shows the predicted number of removals of the currently in-service circuit breakers for each of the next five years and the five year total.

The figure can be interpreted as probability distributions. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 8 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 8 or fewer.

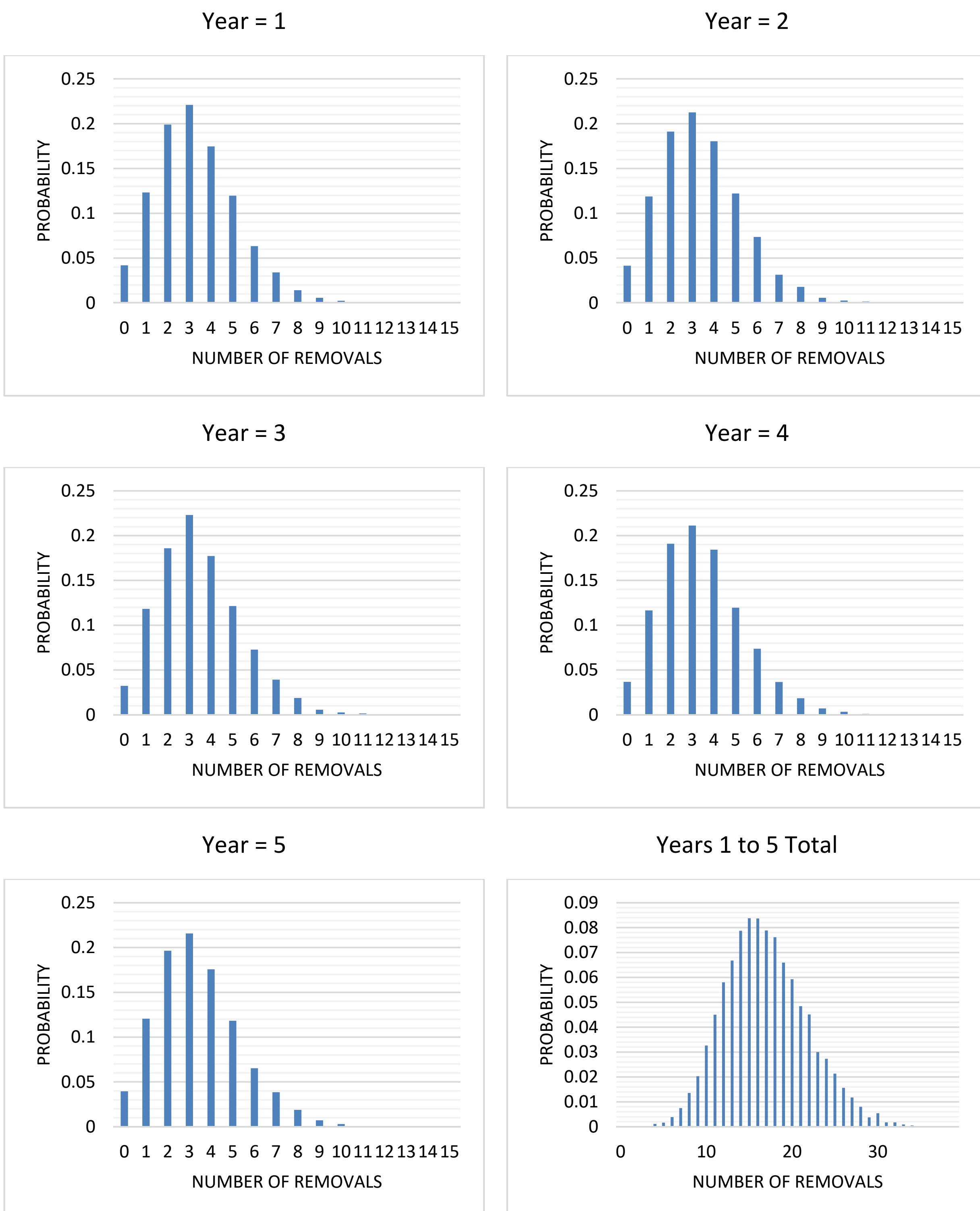

Figure 2-3
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years44 kV Oil Circuit breakers

3
REMOVAL ANALYSIS RESULTS

Using the data provided by Hydro One described in Chapter 1. The following chapter provides the results of the application of the model describe in Chapter 2 for each of the circuit breaker groupings.

Each group results will include the following plots:

In-service Age Demographics: Shows the age distribution in years for the specific circuit breaker group.

Removed from Service: Shows the age distribution in years for the specific circuit breaker group.

Service Eras: Provides information about the completeness of the data set. The horizontal axis is in years. Each horizontal line represents a circuit breaker recorded. The black lines show the installation dates. If a line is gray, the circuit breaker is still in service. If a line turns red, the circuit breaker has been removed from service on the date of the color change.

Service Ages: Provides information about the completeness of the data set. The horizontal axis is the age of the circuit breakers. Each horizontal line represents a distinct circuit breaker denoted by an index number. The removals and in-service are separated and then ordered by installation date. The horizontal line lengths represent the ages for which each circuit breaker was in the record, that is, how long it was observed after the truncation date. The left end point of each horizontal line is the Enter Age. The vertical red lines are removal ages.

Removal Hazard Function: The Weibull model hazard function provides the rate of removal. It can be interpreted as the conditional probability of removal in the next unit of time conditioned on surviving up to the beginning of that time unit.

Survival Function: The survival function derived from the Weibull model provides the rate of survival (not being removed).Shows the expected rate of survival per year as the circuit breaker ages. The middle line is the mean value. The top and bottom lines show the 95% confidence limits. The black line is the actual event data survival function calculated using the Kaplan-Meier technique. The Kaplan-Meier technique is an established statistical technique for developing a non-parametric estimate of the survival function based on the observed data.

Yearly Removal Predictions for the Next Five Years: Shows the predicted number of removals of the currently in-service circuit breakers for each of the next five years. The hazard functions has been convoluted with the corresponding in-service population to provide forecasts of anticipated removals.

Cumulative Five Year Removal Predictions: Shows the cumulative predicted number of removals of the currently in-service circuit breakers for next the five years.

13 – 27 kV Air Removal Analysis

The following provides the results of the 13 – 27 kV air blast circuit breaker group analyzed using the method describe in Chapter 2. Table 3-1 shows the number of circuit breakers in-service and removed from service.

Table 3-1
Circuit breaker Group Data 13 – 27 kV Air Blast

Group	In-service	Removed from Service
13 – 27 kV Air Blast	37	21

Age Demographics13 – 27 kV Air Blast

Figures 3-1 and 3-2 show the age demographics for both in service and removed from service circuit breaker units.

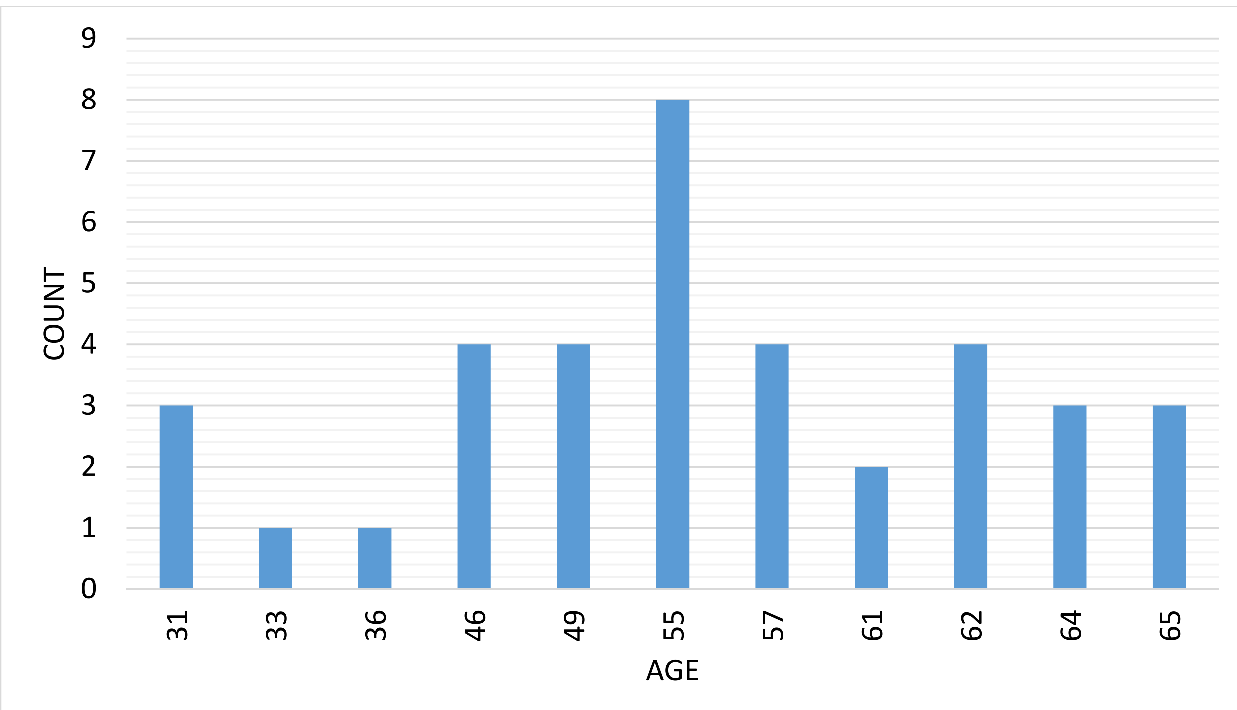

Figure 3-1
Age Demographics In-service 13 – 27 kV Air Blast

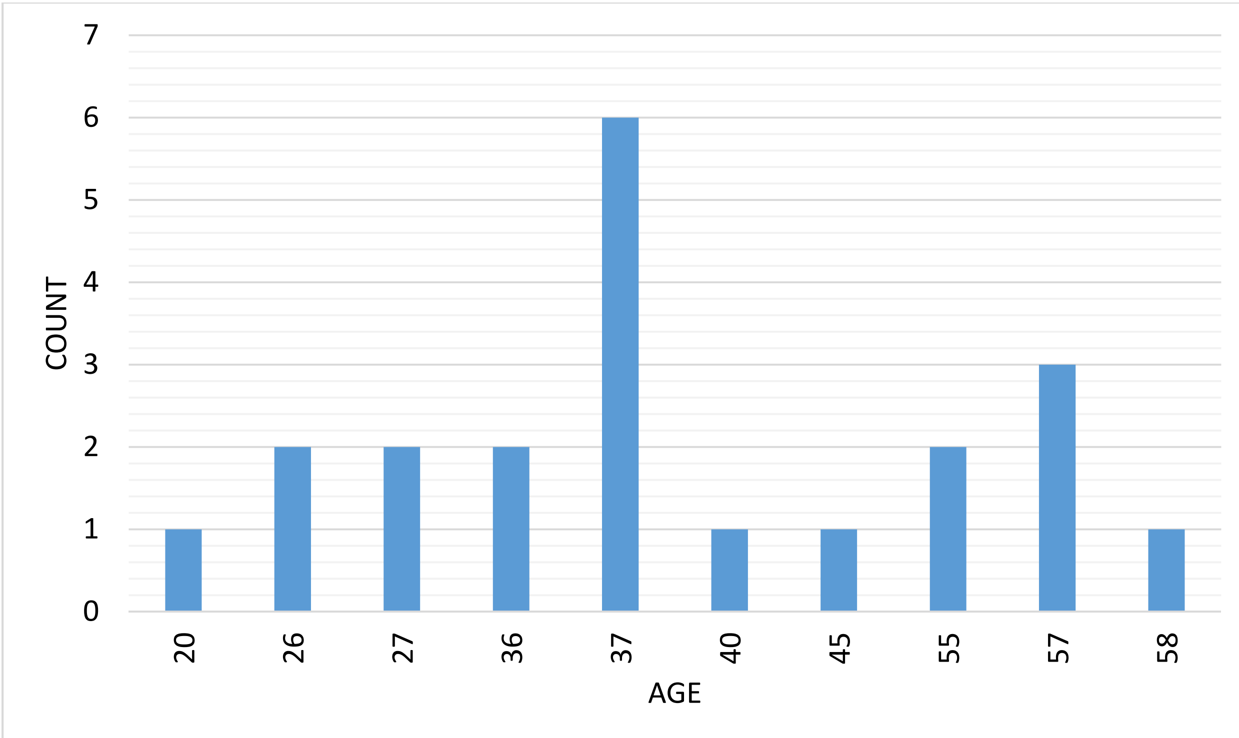

Figure 3-2
Age Demographics Removed From Service 13 – 27 kV Air Blast

Figures 3-3 and 3-4 show the Service Eras and Service Ages of the 13 – 27 kV Air Blast circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1994.

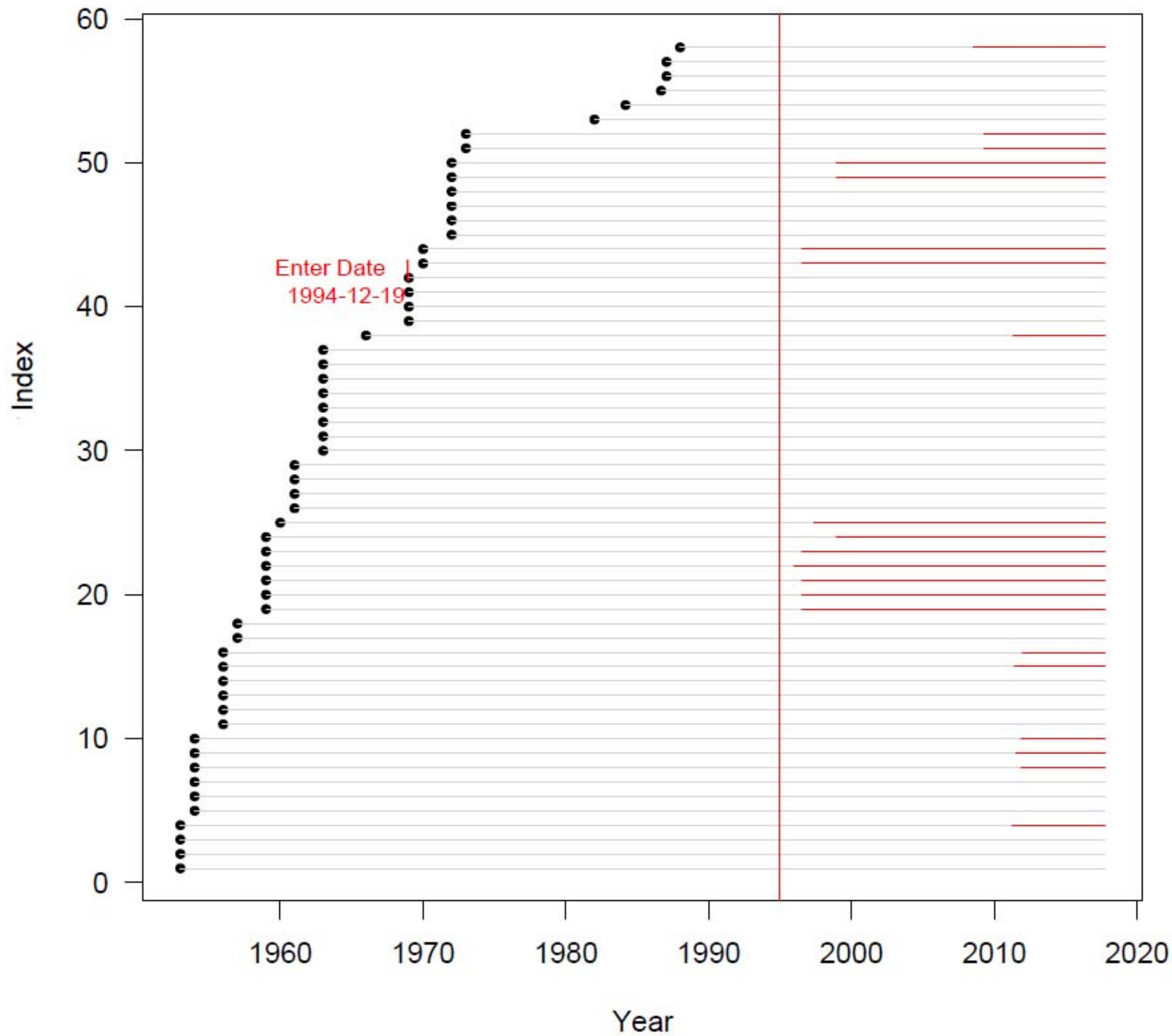

Figure 3-3
Service Eras 13 – 27 kV Air Blast

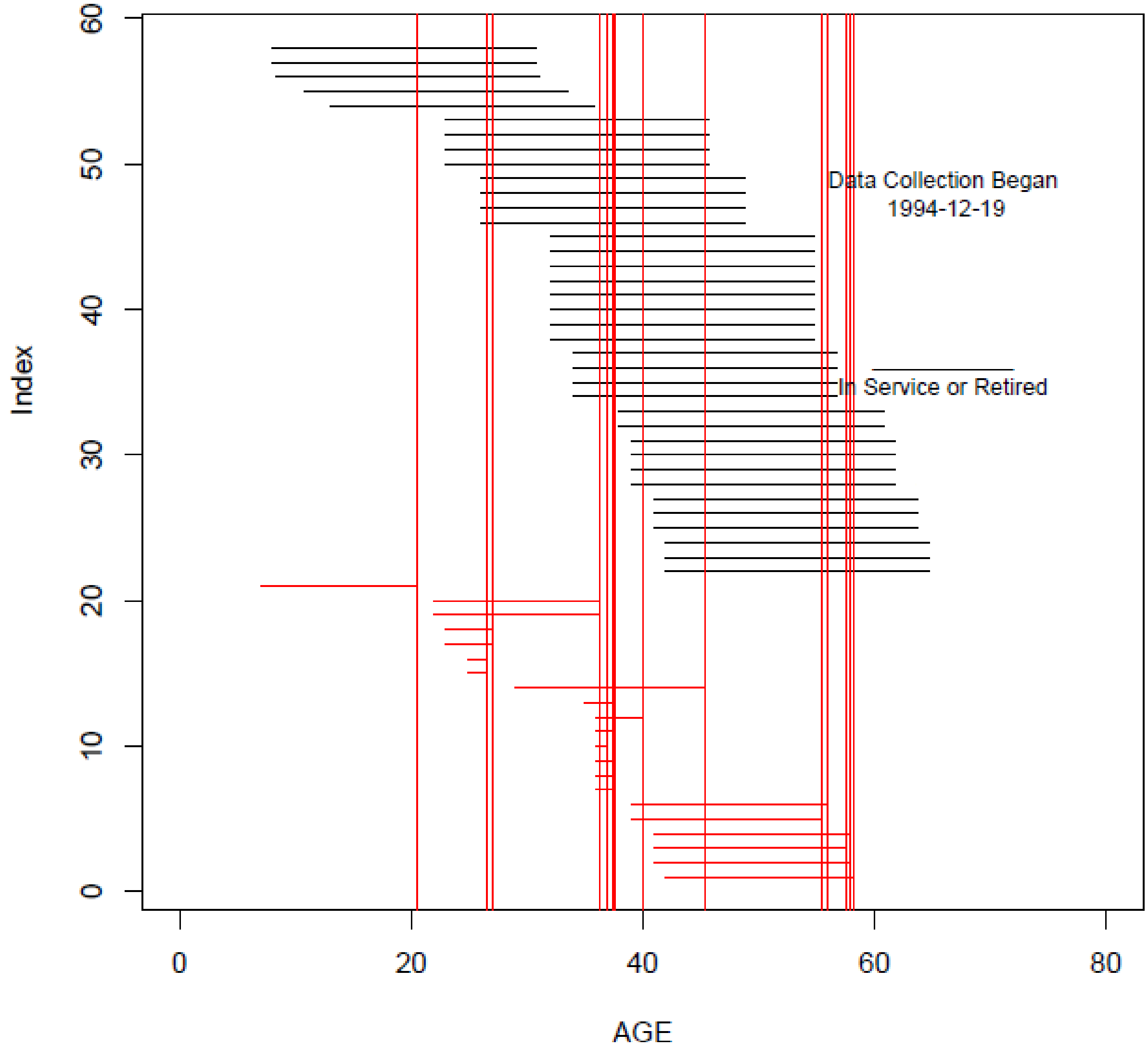

Figure 3-4
Service Ages 13 – 27 kV Air Blast

Removal Hazard Rate13 – 27 kV Air Blast

Figure 3-5 shows the removal rate developed using the in-service and removed from service data provided for the 13 – 27 kV Air Blast circuit breaker. In the figure, probability of a 20 year old circuit breaker being removed in its next year of life ranges from 0.6% to 2.3%. For a 40 year old circuit breaker the probability of being removed in its next year of life ranges from 1.1% to 2.8%.

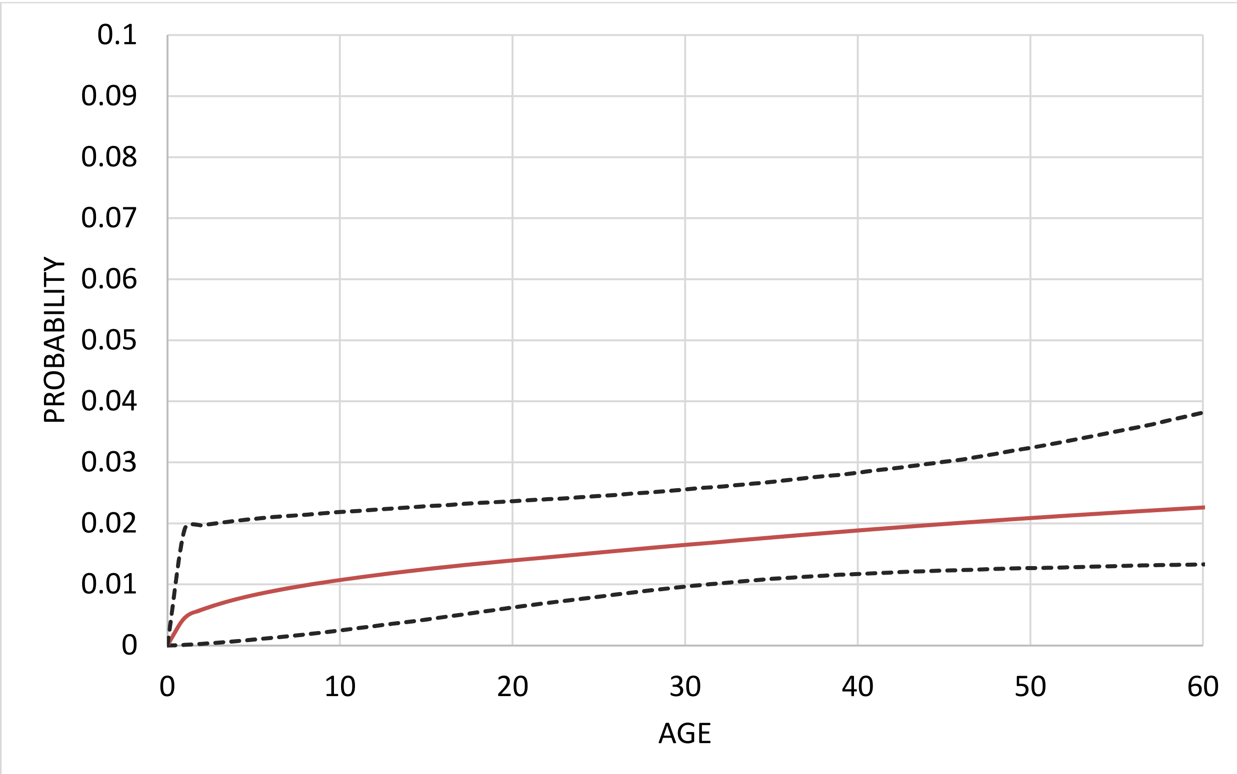

Figure 3-5
Removal Hazard Rate 13 – 27 kV Air Blast

Survival Function 13 – 27 kV Air Blast

Figure 3-6 shows the survival function developed using the in-service and removed from service data provided for the 13 – 27 kV Air Blast circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 38% to 77%.

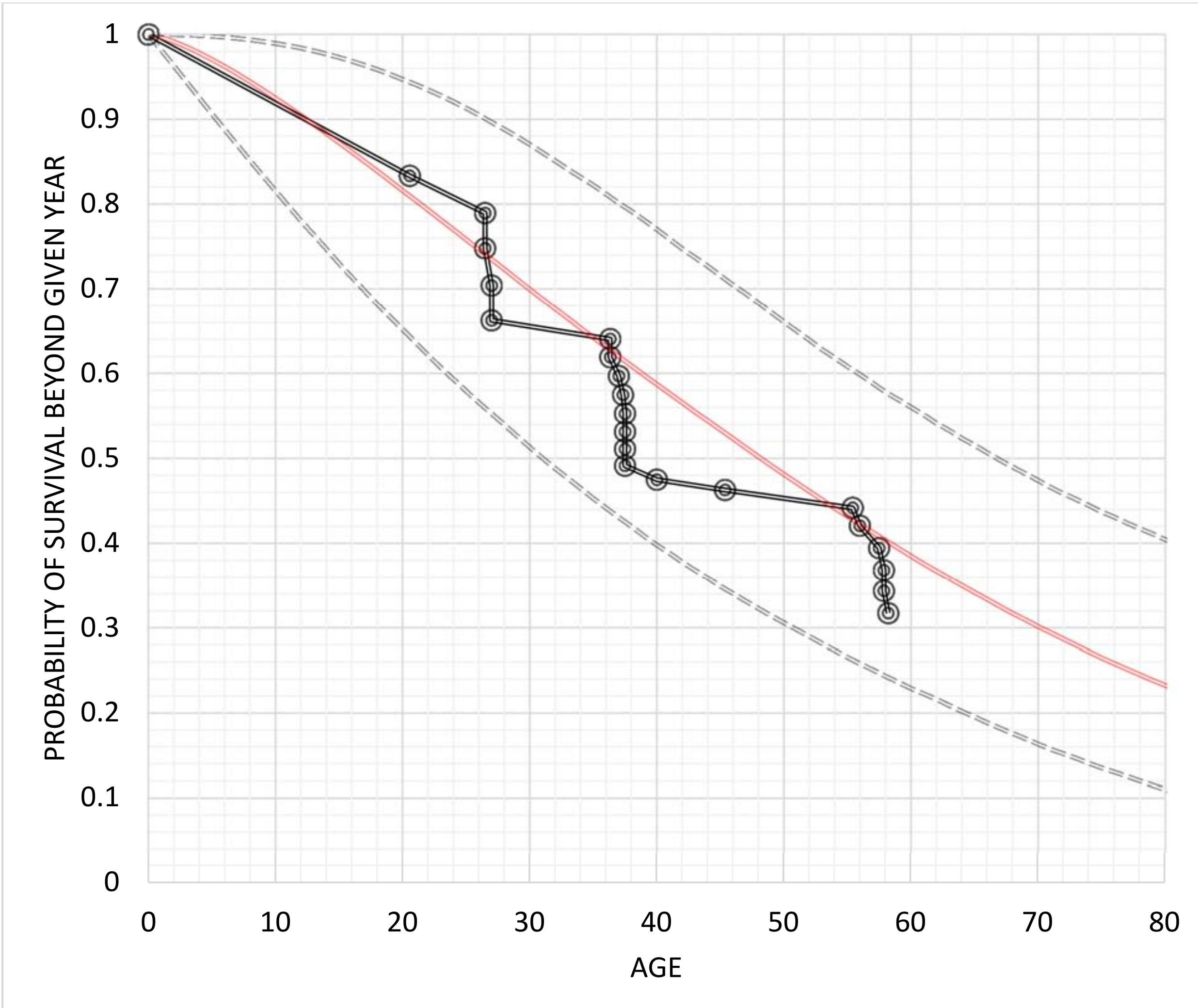

Figure 3-6
Survival Function 13 – 27 kV Air Blast

Forecasting Removals

Figures 3-7 and 3-8 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-7. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 3 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 3 or fewer. Figure 3-8 presents the cumulative results combining each year of the five year period.

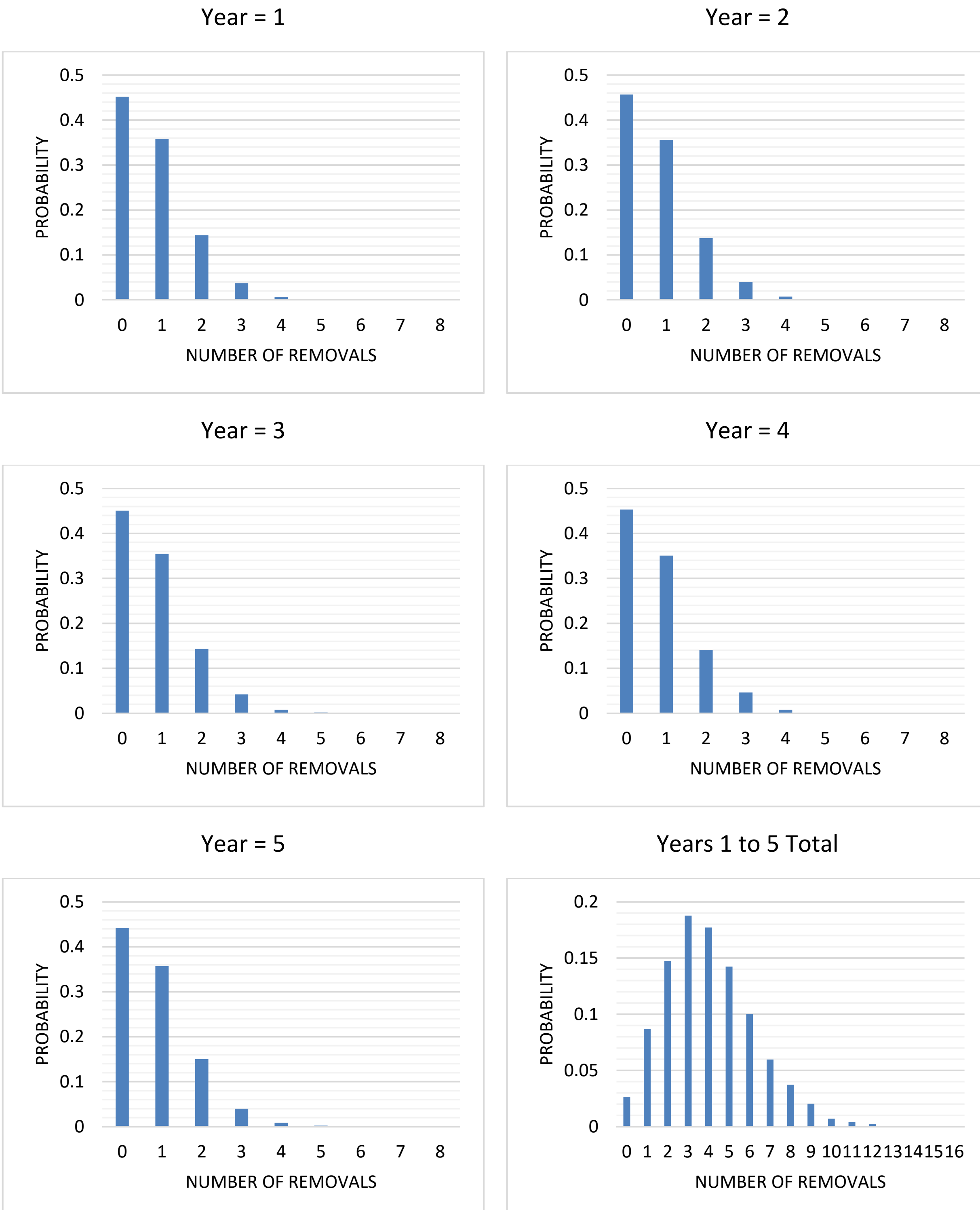

Figure 3-7
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 13 – 27 kV Air Blast Circuit breakers

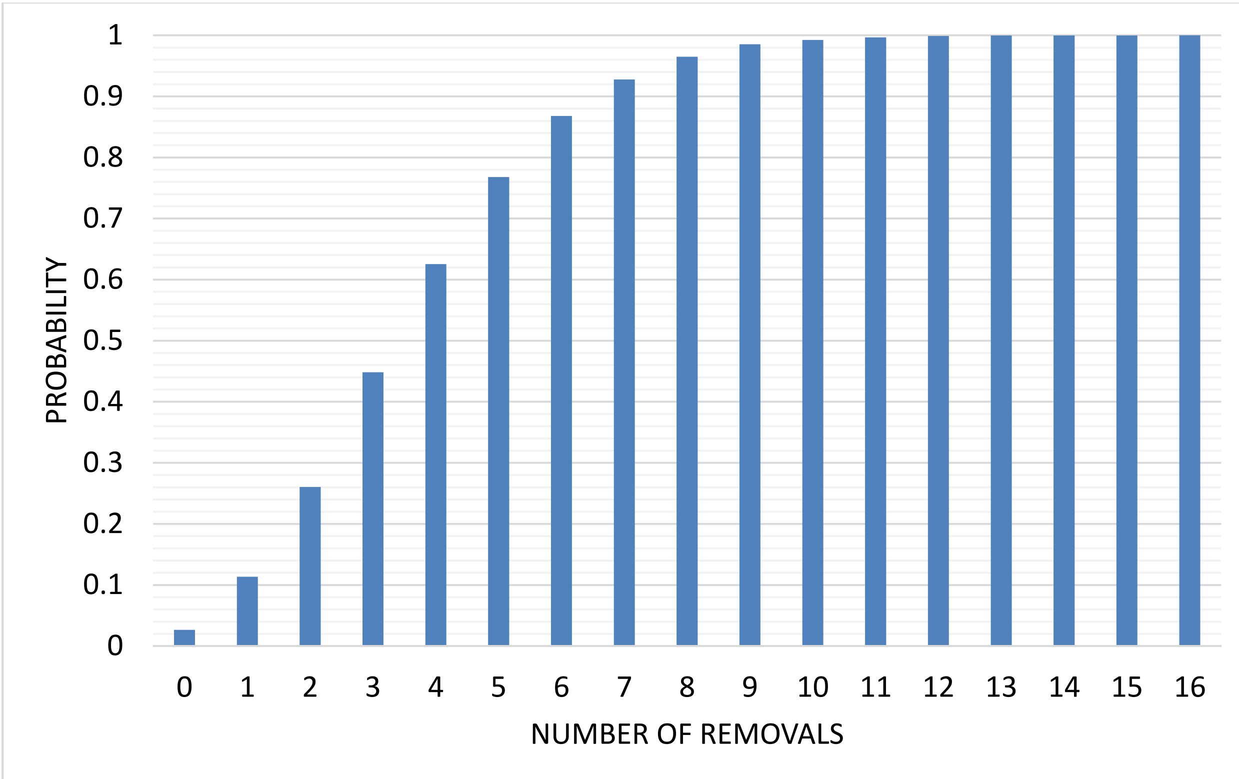

Figure 3-8
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 13 – 27 kV Air Blast

13 – 27 kV Gas Removal Analysis

The following provides the results of the 13 – 27 kV Gas circuit breaker group analyzed using the method describe in Chapter 2. Table 3-2 shows the number of circuit breakers in-service and removed from service.

Table 3-2
Circuit breaker Group Data 13 – 27 kV Gas

Group	In-service	Removed from Service
13 – 27 kV Gas	911	163

Age Demographics 13 – 27 kV Gas

Figures 3-9 and 3-10 show the age demographics for both in service and removed from service circuit breaker units.

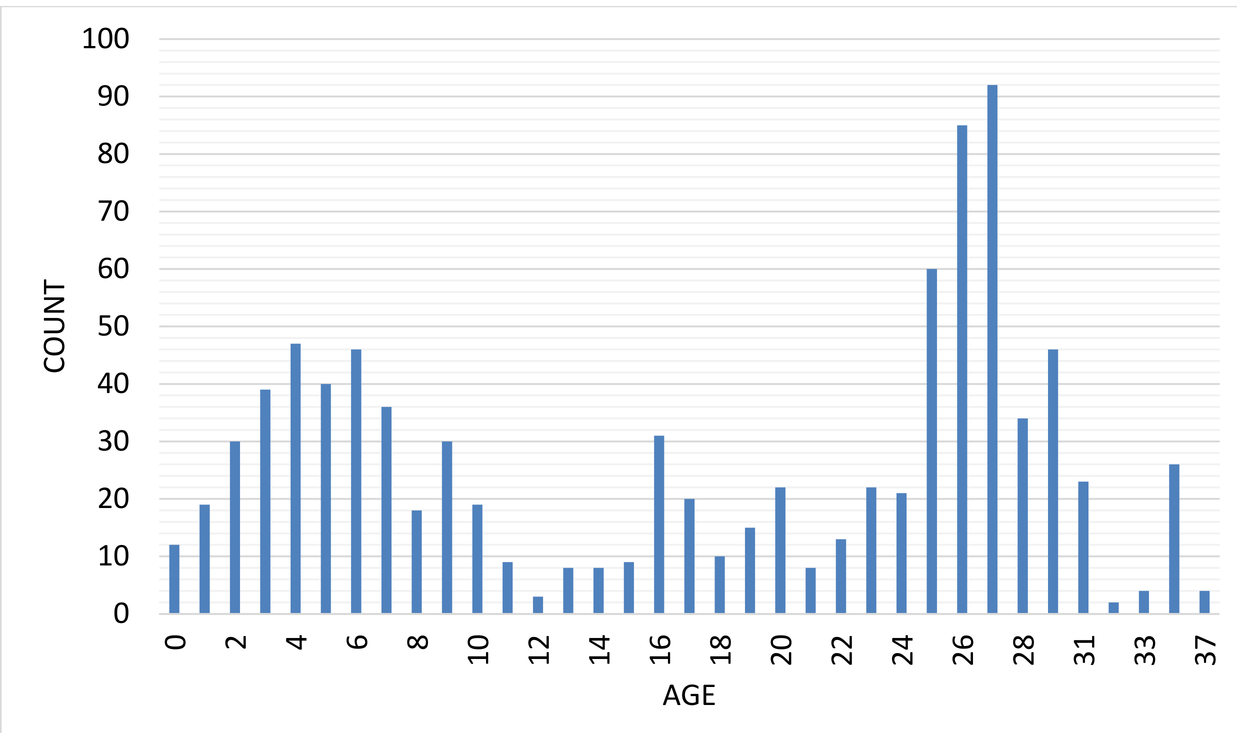

Figure 3-9
Age Demographics In-service 13 – 27 kV Gas

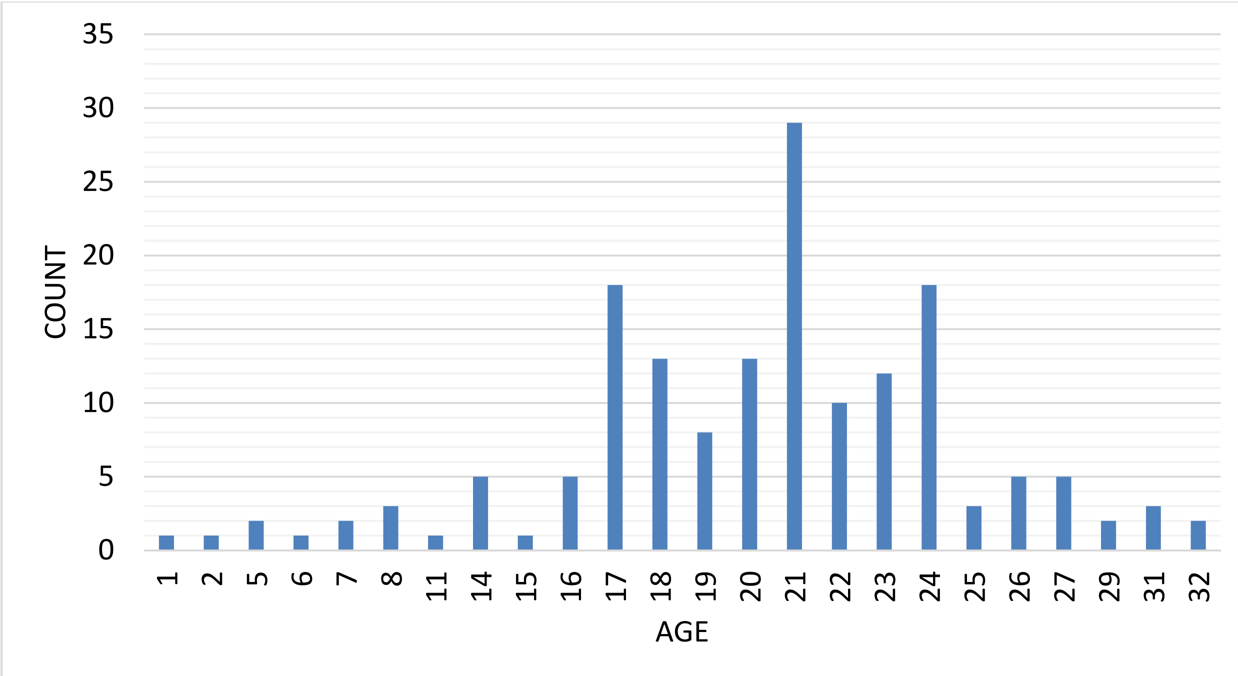

Figure 3-10
Age Demographics Removed From Service 13 – 27 kV Gas

Figures 3-11 and 3-12 show the Service Eras and Service Ages of the 13 – 27 kV Gas circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1992.

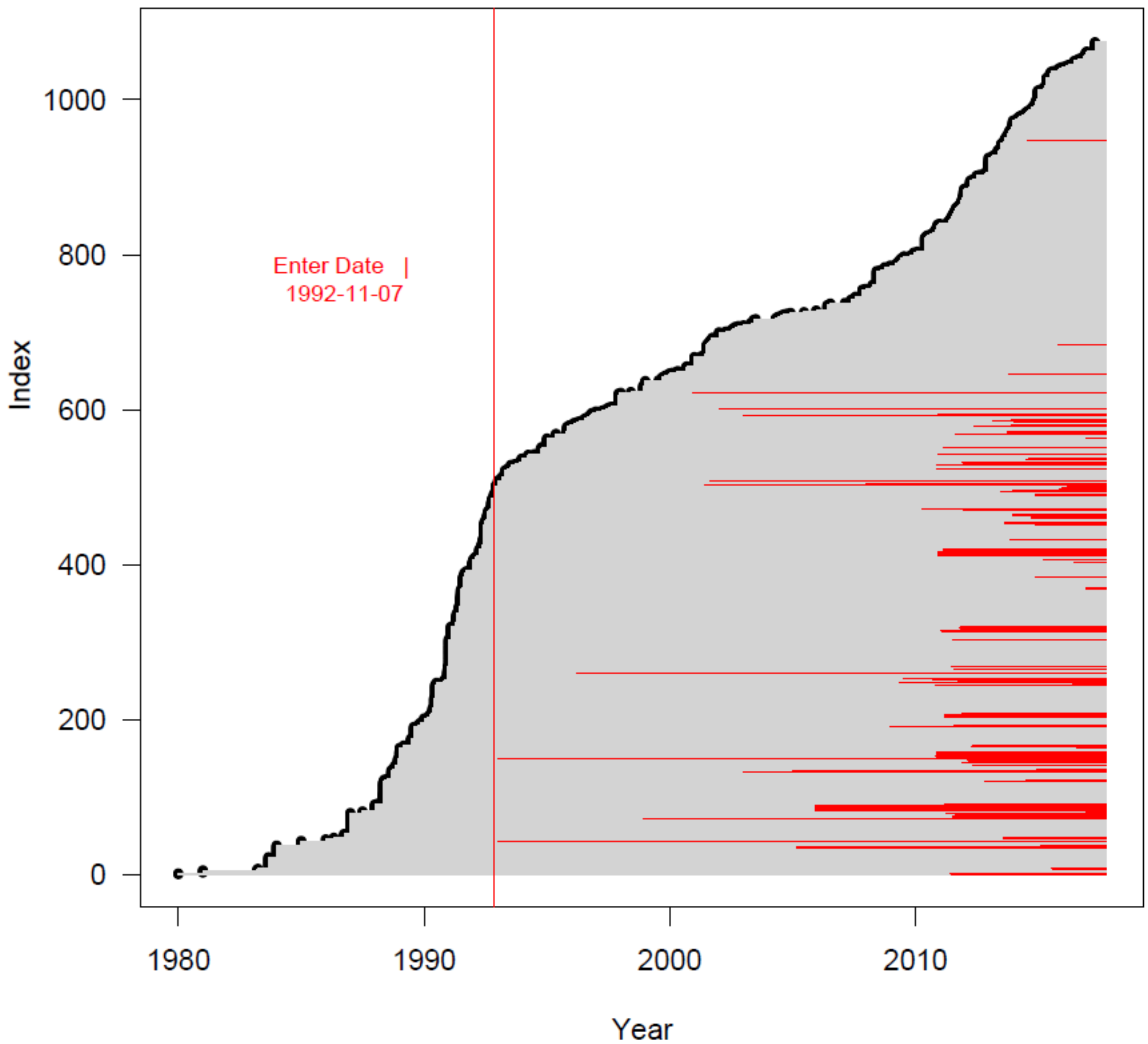

Figure 3-11
Service Eras 13 – 27 kV Gas

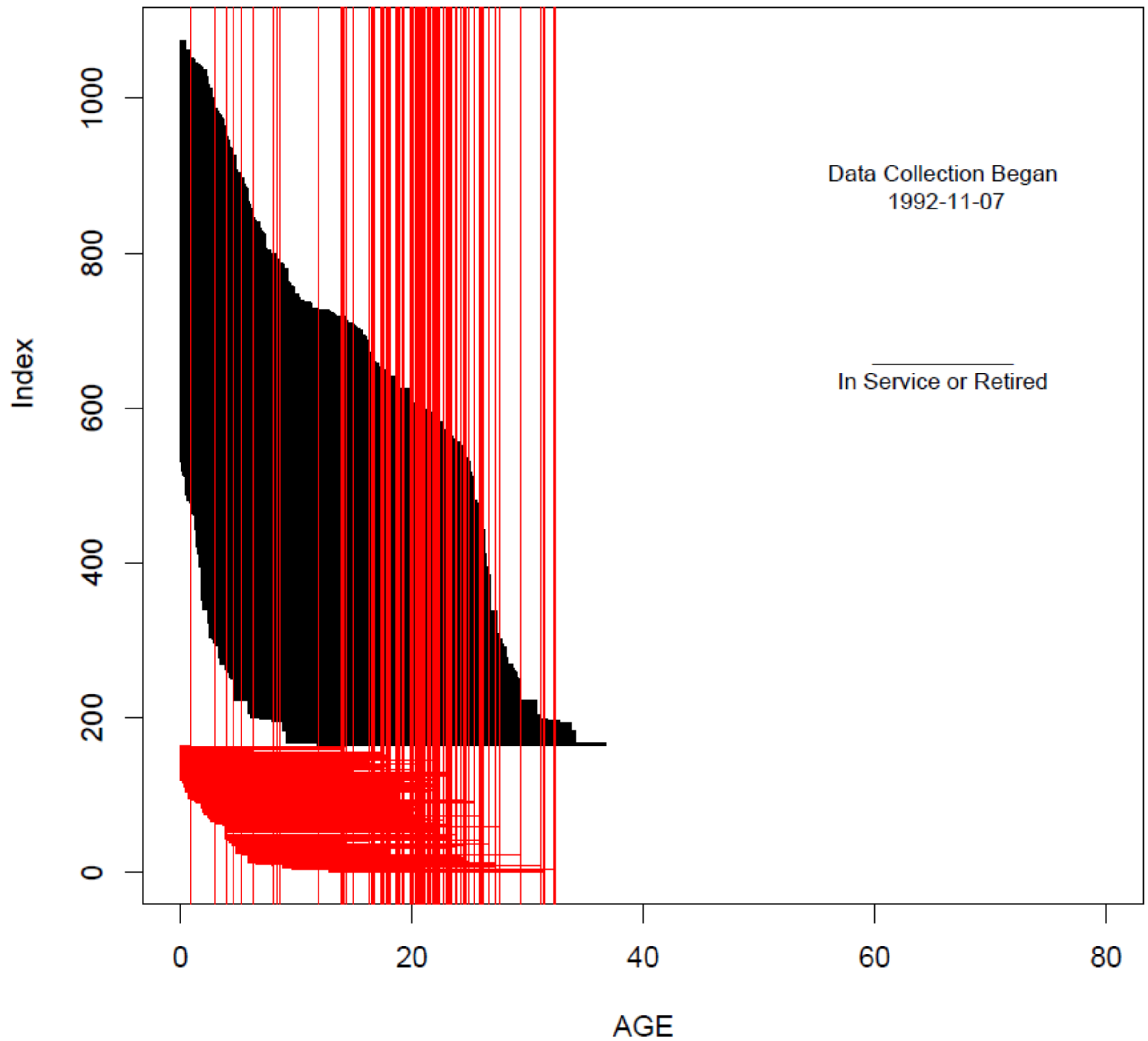

Figure 3-12
Service Ages 13 – 27 kV Gas

Removal Hazard Rate 13 – 27 kV Gas

Figure 3-13 shows the removal rate developed using the in-service and removed from service data provided for the 13 – 27 kV Gas circuit breaker. In the figure, probability of a 40 year old circuit breaker being removed in its next year of life ranges from 0.5% to 1.2%. For a 60 year old circuit breaker the probability of being removed in its next year of life ranges from 1.1% to 3.2%. Note the 95% confidence intervals. The bands become larger above age50, reflecting the sparse number of recorded removals in these regions.

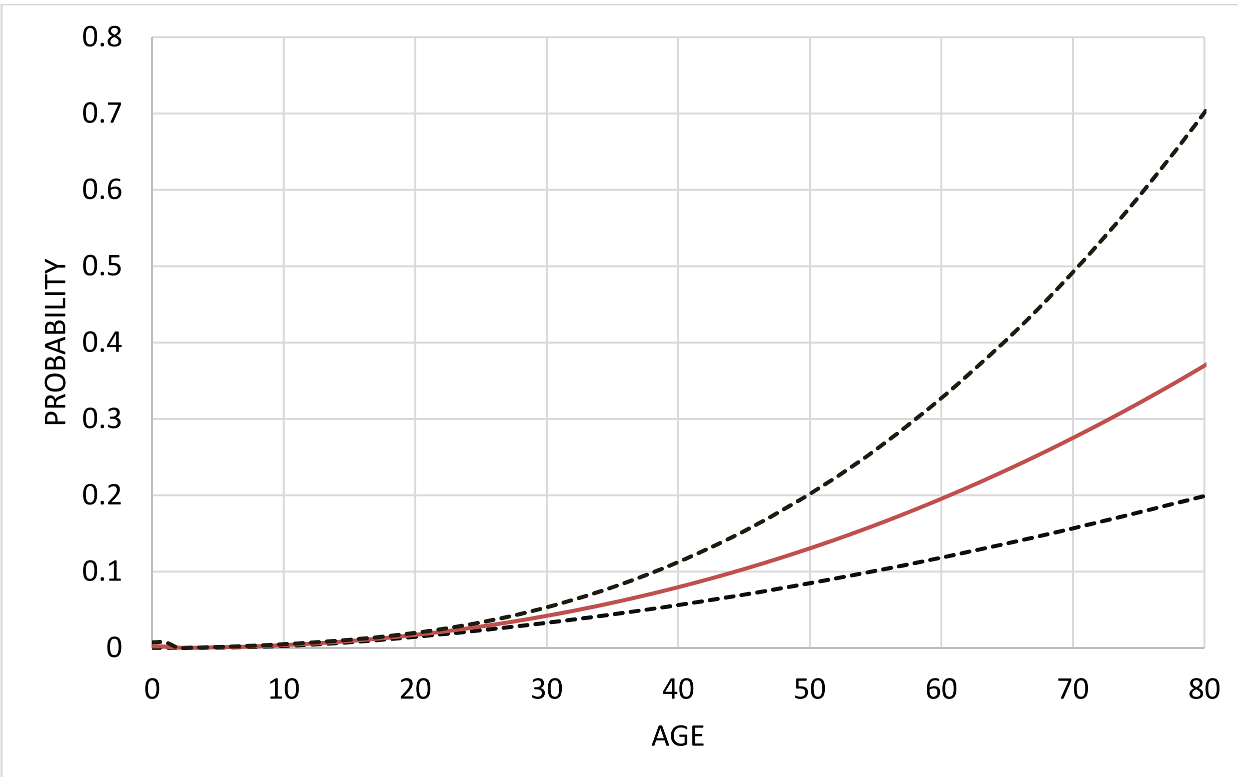

Figure 3-13
Removal Rate 13 – 27 kV Gas

Survival Function 13 – 27 kV Gas

Figure 3-14 shows the survival function developed using the in-service and removed from service data provided for the 13 – 27 kV Gas circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 28% to 45%.

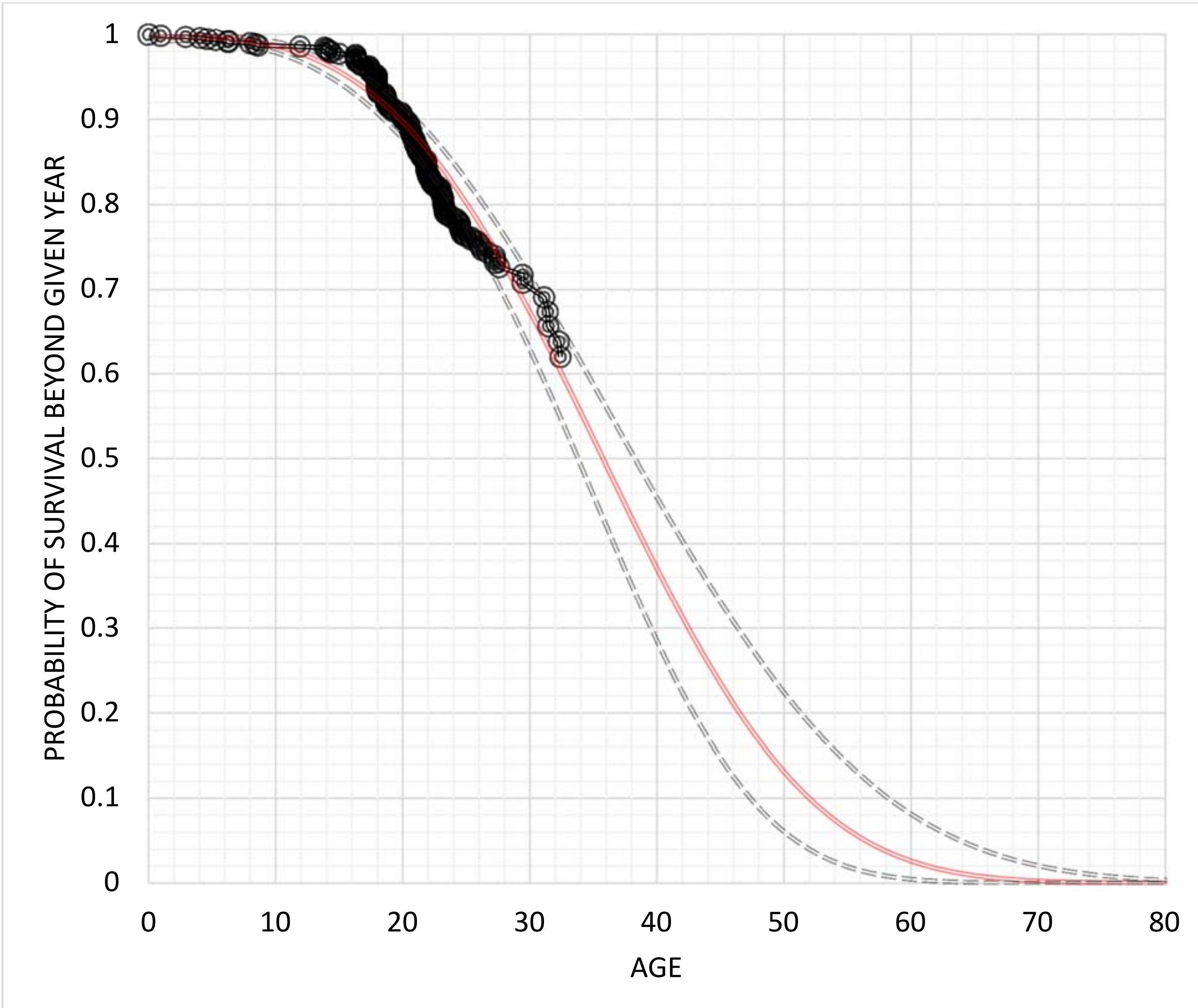

Figure 3-14
Survival Function 13 – 27 kV Gas

Forecasting Removals

Figures 3-15 and 3-16 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-15. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 27 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 27 or fewer. Figure 3-15 presents the cumulative results combining each year of the five year period.

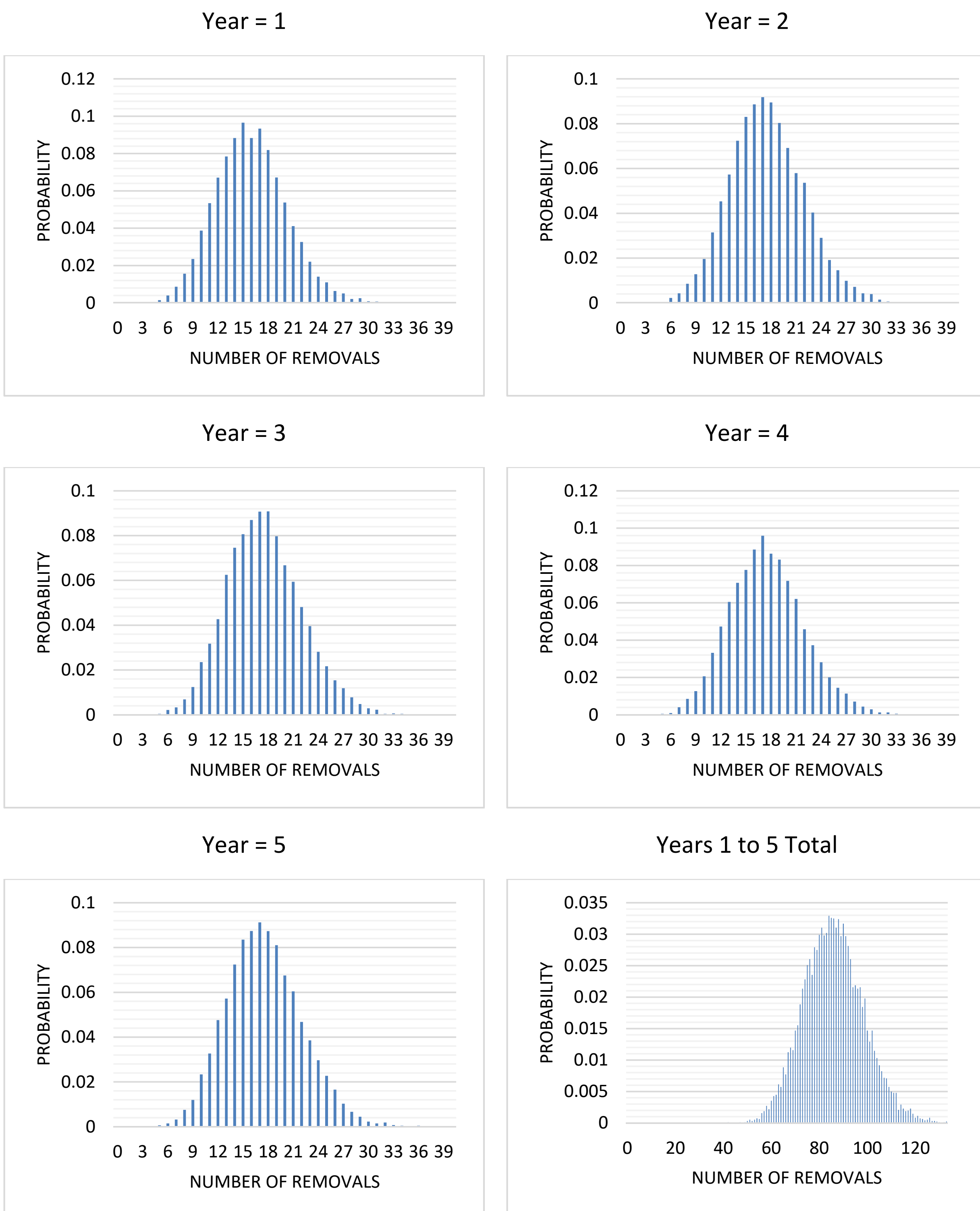

Figure 3-15
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 13 – 27 kV Gas

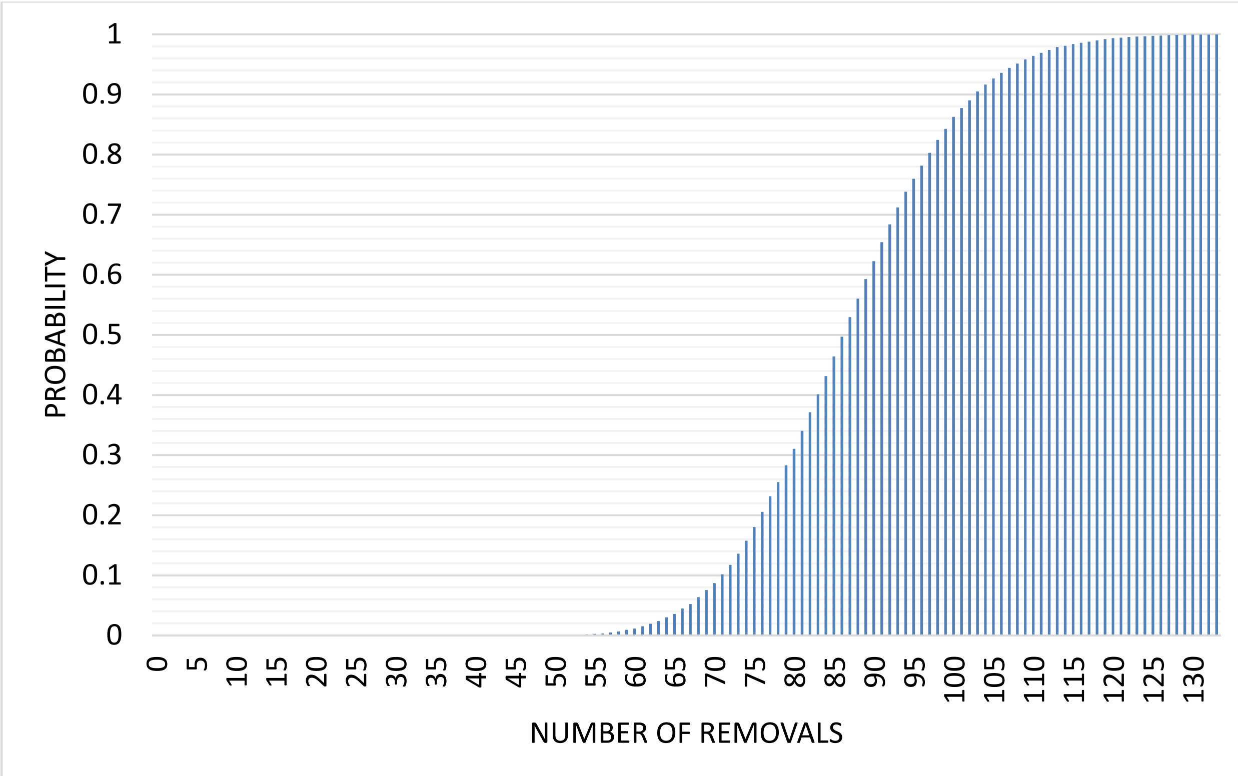

Figure 3-16
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 13 – 27 kV Gas

13 – 27 kV Oil Auto Removal Analysis

The following provides the results of the 13 – 27 kV Oil circuit breaker group analyzed using the method describe in Chapter 2. Table 3-3 shows the number of circuit breakers in-service and removed from service.

Table 3-3
Circuit breaker Group Data 13 – 27 kV Oil

Group	In-service	Removed from Service
13 – 27 kV Oil	835	357

Age Demographics 13 – 27 kV Oil

Figures 3-17 and 3-18 show the age demographics for both in service and removed from service circuit breaker units.

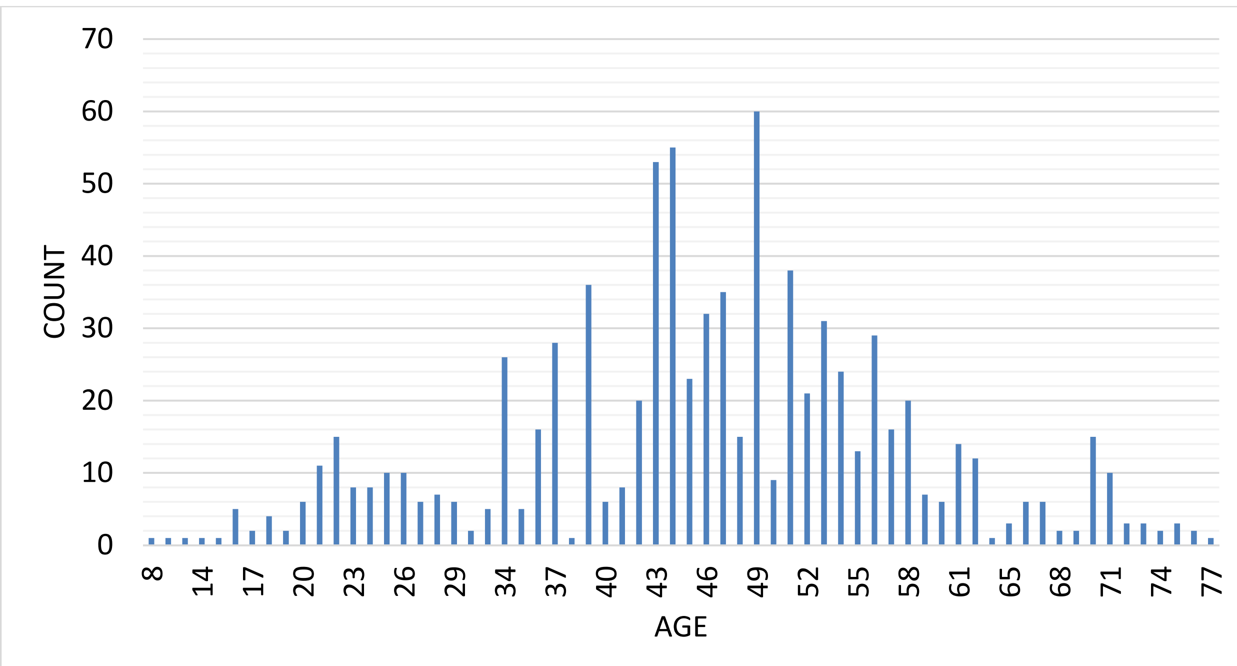

Figure 3-17
Age Demographics In-service 13 – 27 kV Oil

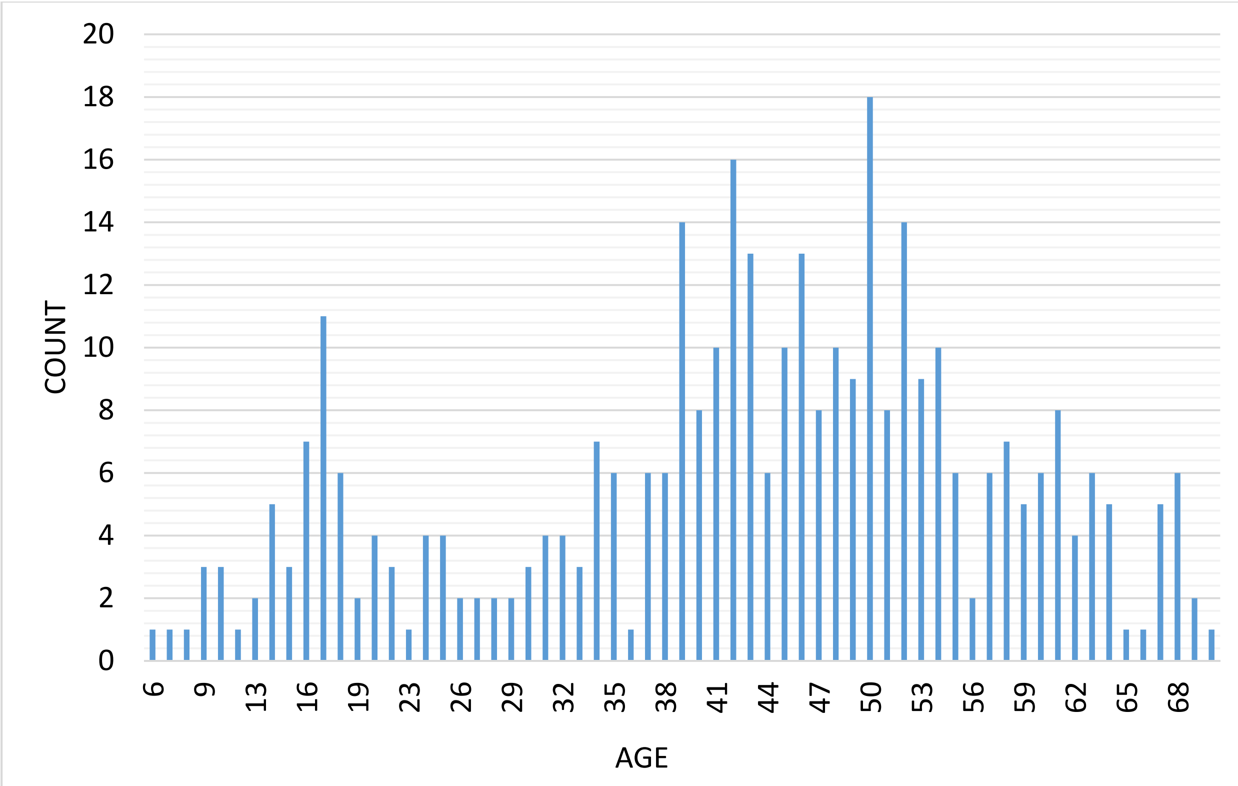

Figure 3-18
Age Demographics Removed From Service 13 – 27 kV Oil

Figures 3-18 and 3-19 show the Service Eras and Service Ages of the 13 – 27 kV Oil circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1988.

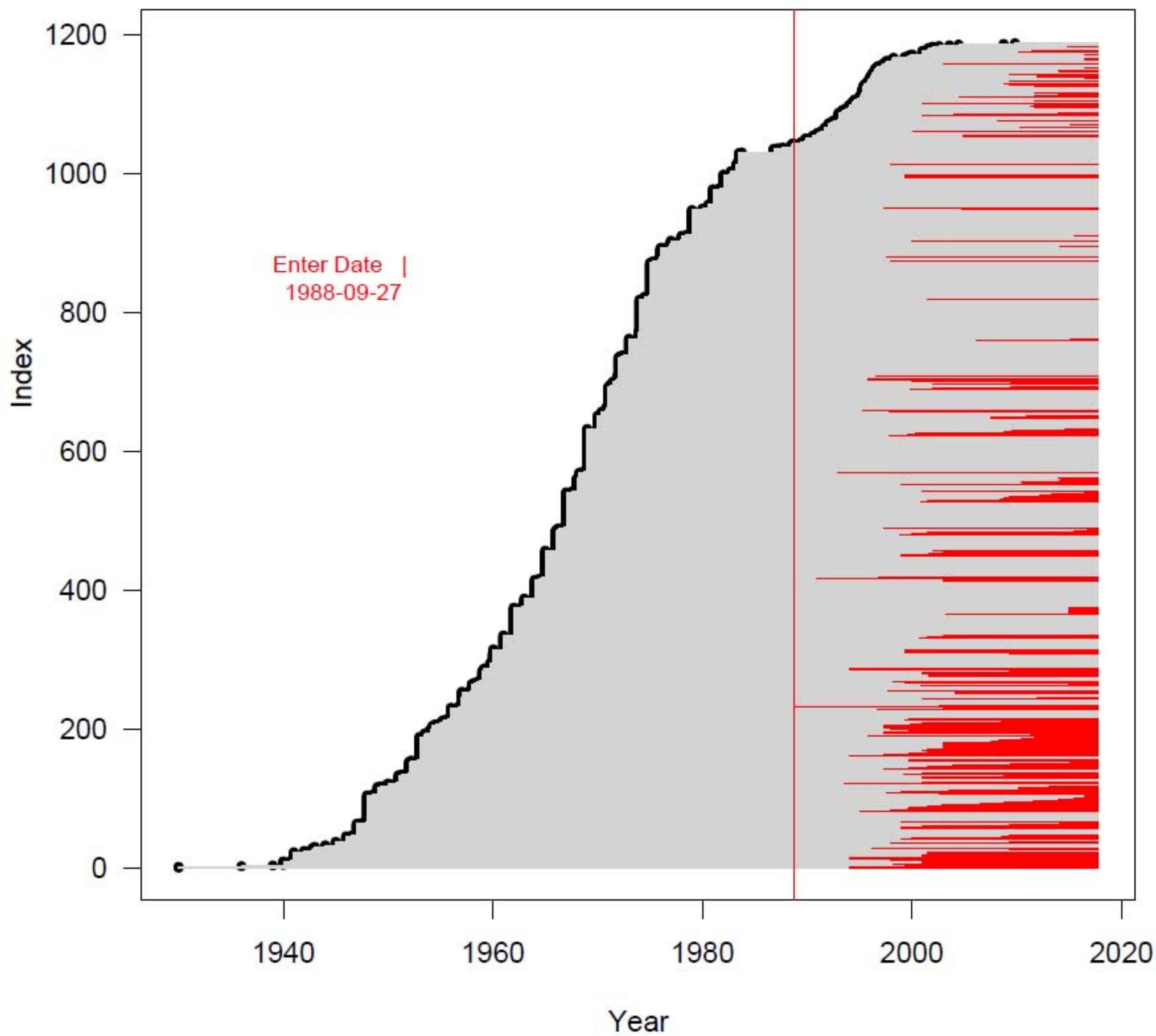

Figure 3-19
Service Eras 13 – 27 kV Oil

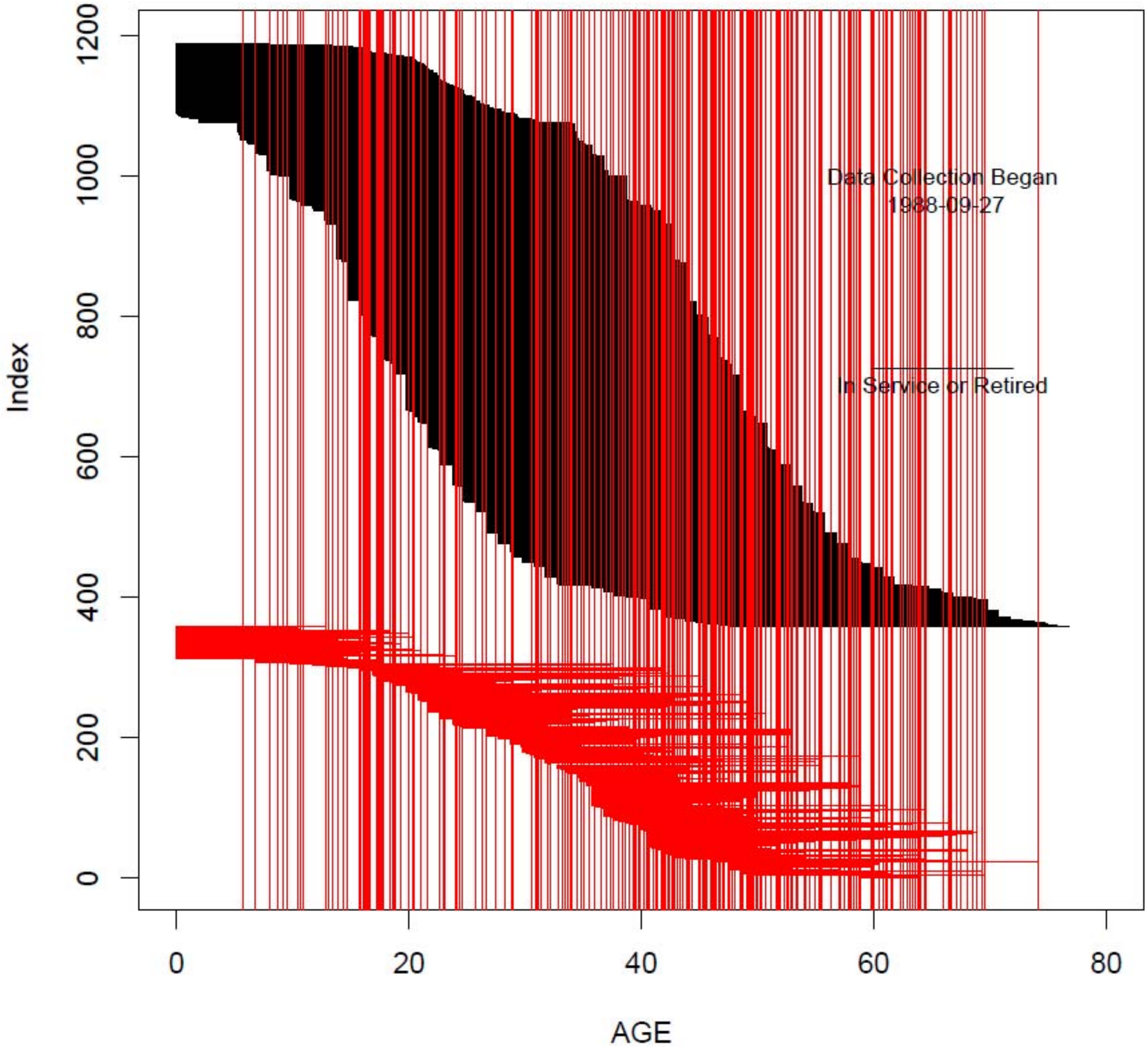

Figure 3-20
Service Ages 13 – 27 kV Oil

Removal Hazard Rate13 – 27 kV Oil

Figure 3-21 shows the removal rate developed using the in-service and removed from service data provided for the 13 – 27 kV Oil circuit breaker. In the figure, probability of a 40 year old circuit breaker being removed in its next year of life ranges from 1.3% to 1.7%. For a 60 year old circuit breaker the probability of being removed in its next year of life ranges from 2.4% to 3.3%. Note the 95% confidence intervals. The bands become larger above age 60, reflecting the sparse number of recorded removals in these regions.

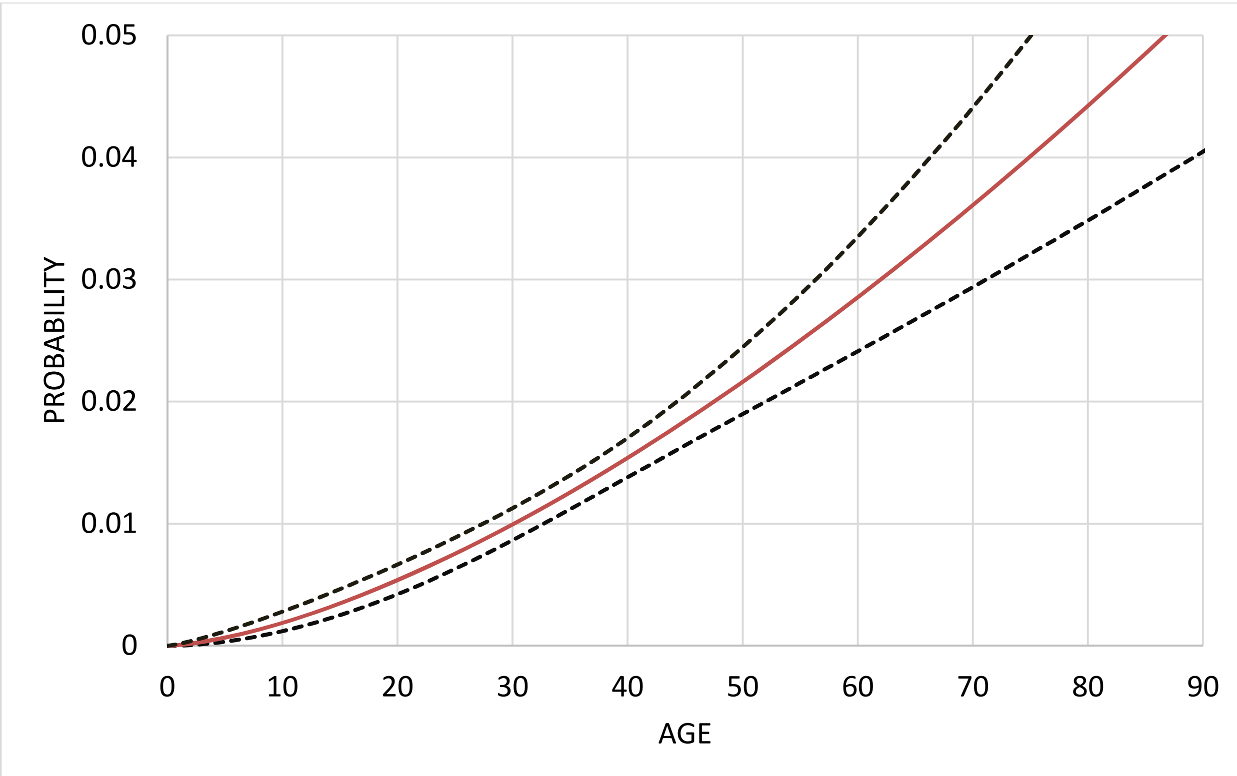

Figure 3-21
Removal Rate 13 – 27 kV Oil

Survival Function 13 – 27 kV Oil

Figure 3-22 show the survival function developed using the in-service and removed from service data provided for the 13 – 27 kV Oil circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 75% to 81%.

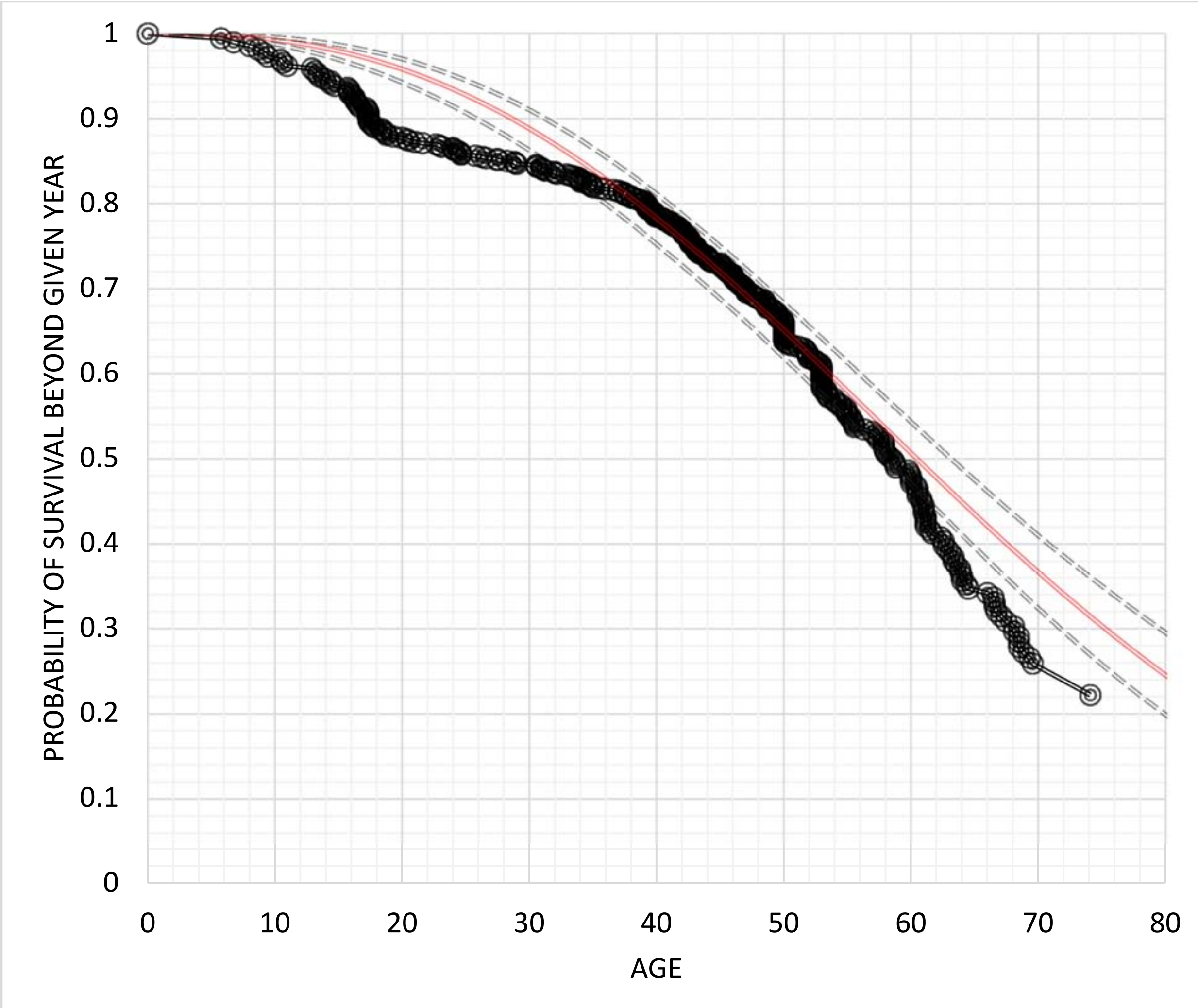

Figure 3-22
Survival Function 13 – 27 kV Oil

Forecasting Removals

Figures 3-23 and 3-24 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-23. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 26 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 26 or fewer. Figure 3-24 presents the cumulative results combining each year of the five year period.

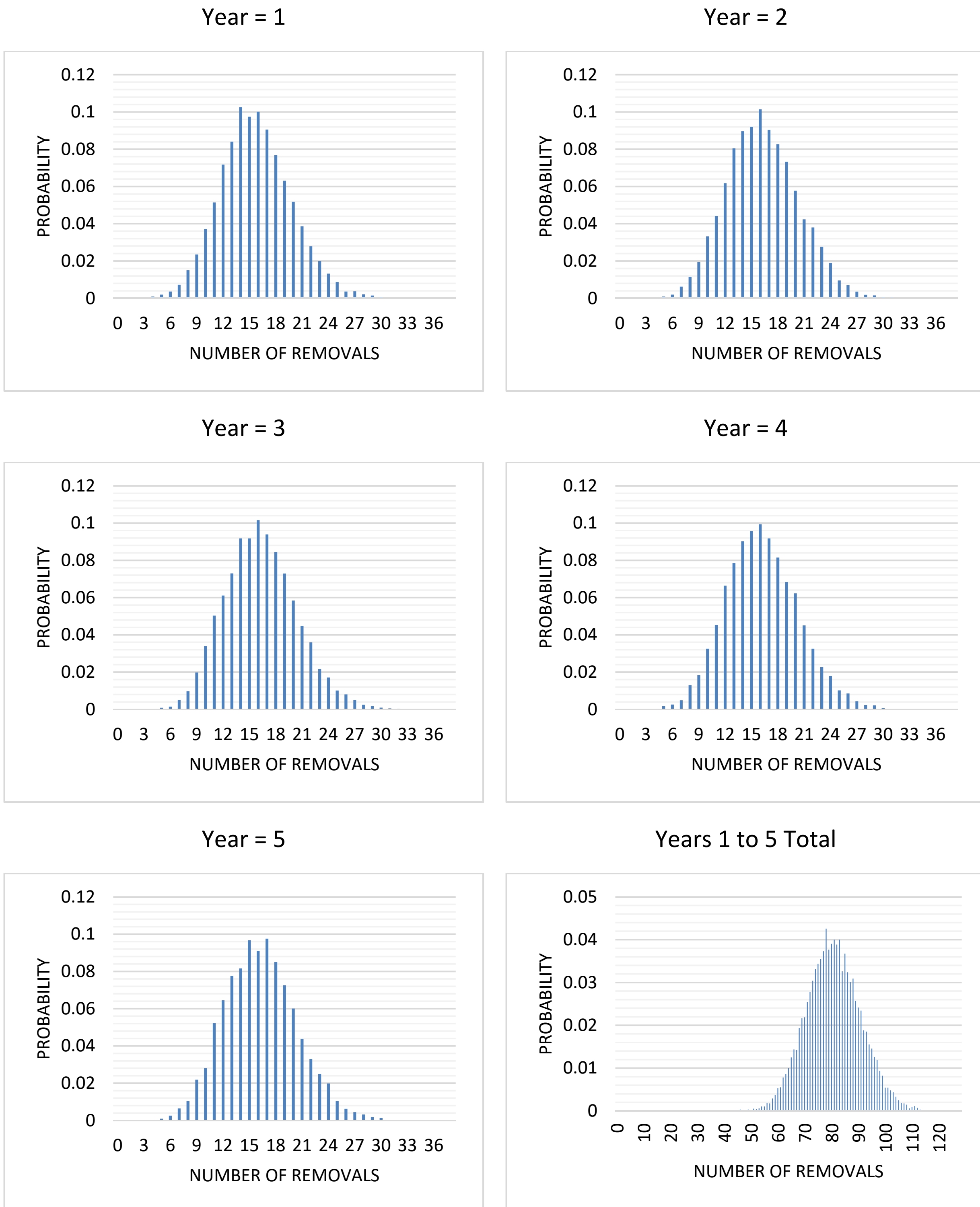

Figure 3-23
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 13 – 27 kV Oil

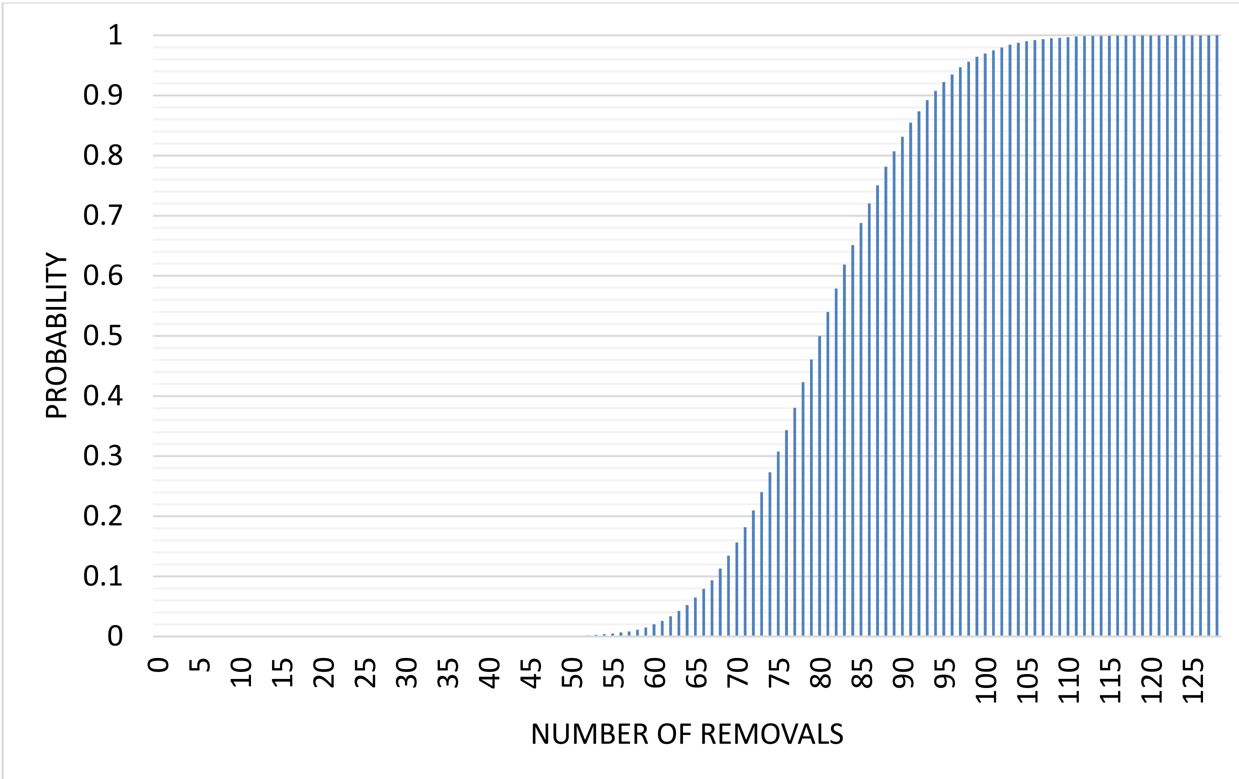

Figure 3-24
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 13 – 27 kV Oil

13 – 27 kV Vacuum Removal Analysis

The following provides the results of the 13 – 27 kV Vacuum circuit breaker group analyzed using the method describe in Chapter 2. Table 3-4 shows the number of circuit breakers in-service and removed from service.

Table 3-4
Circuit breaker Group Data 13 – 27 kV

Group	In-service	Removed from Service
13 – 27 kV Vacuum	344	30

Age Demographics 13 – 27 kV Vacuum

Figures 3-25 and 3-26 show the age demographics for both in service and removed from service circuit breaker units.

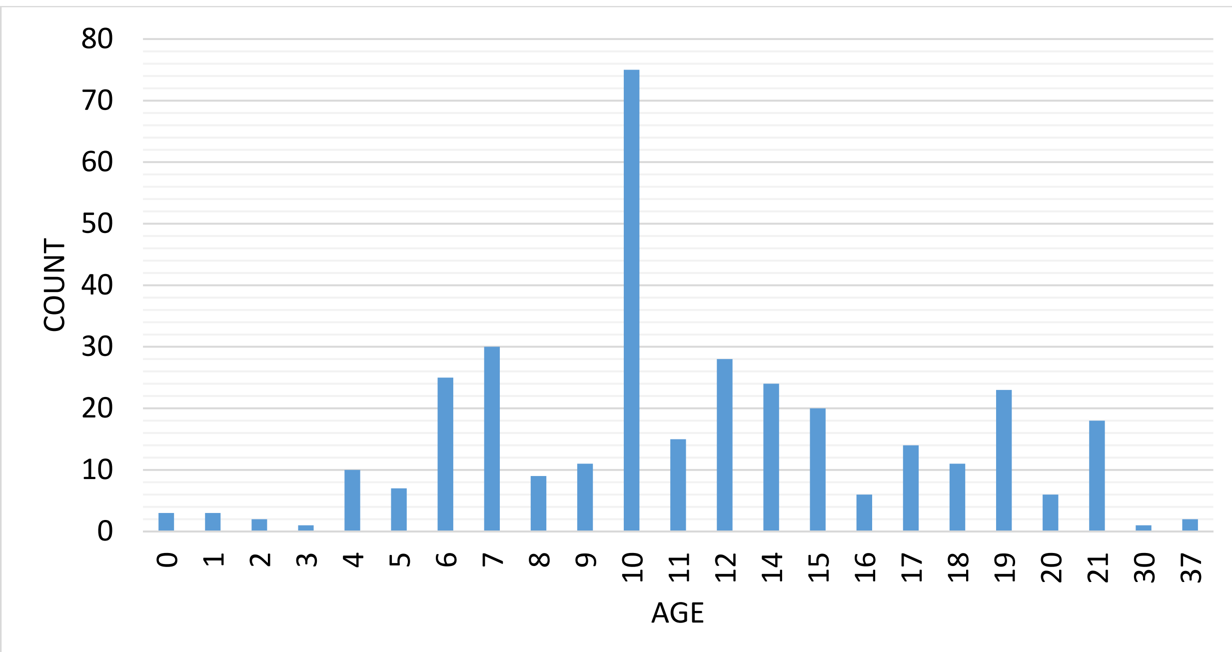

Figure 3-25
Age Demographics In-service 13 – 27 kV Vacuum

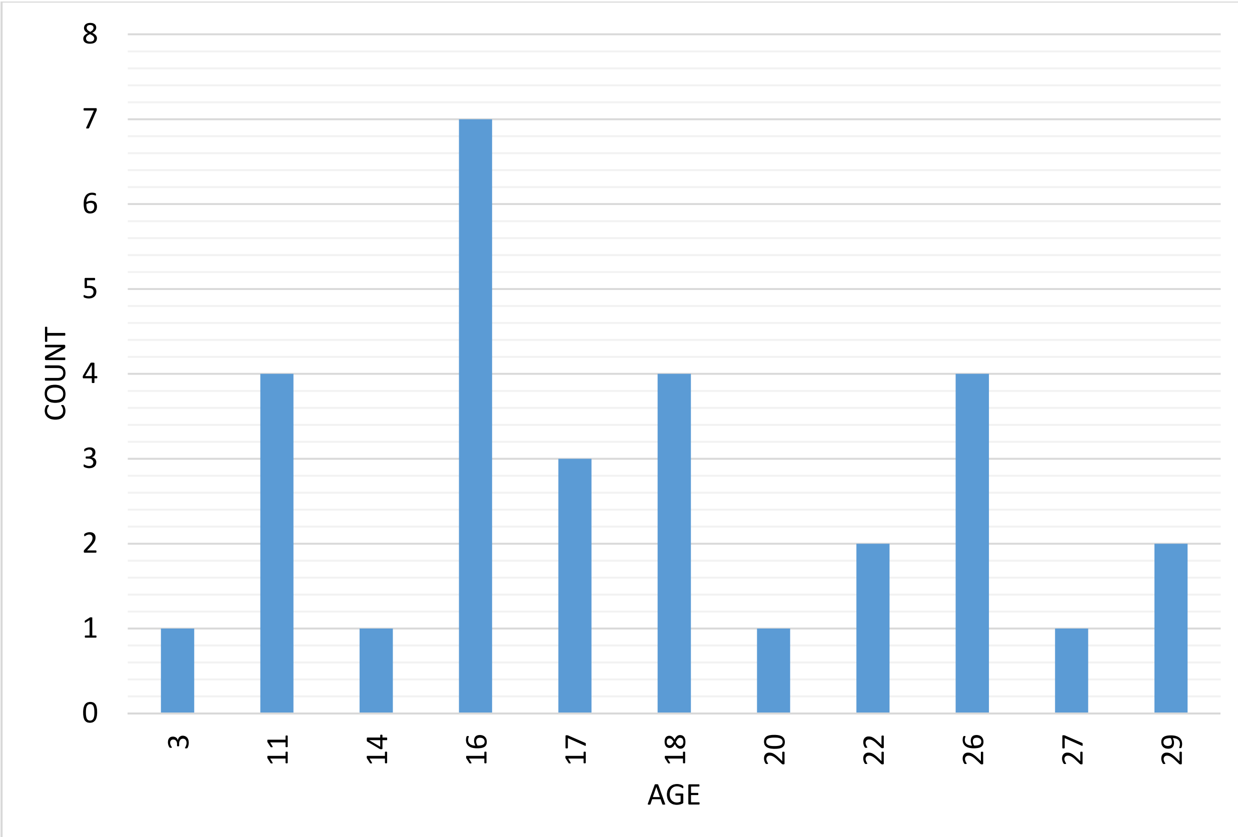

Figure 3-26
Age Demographics Removed From Service 13 – 27 kV Vacuum

Figures 3-27 and 3-28 show the Service Eras and Service Ages of the 13 – 27 kV Vacuum circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 2001.

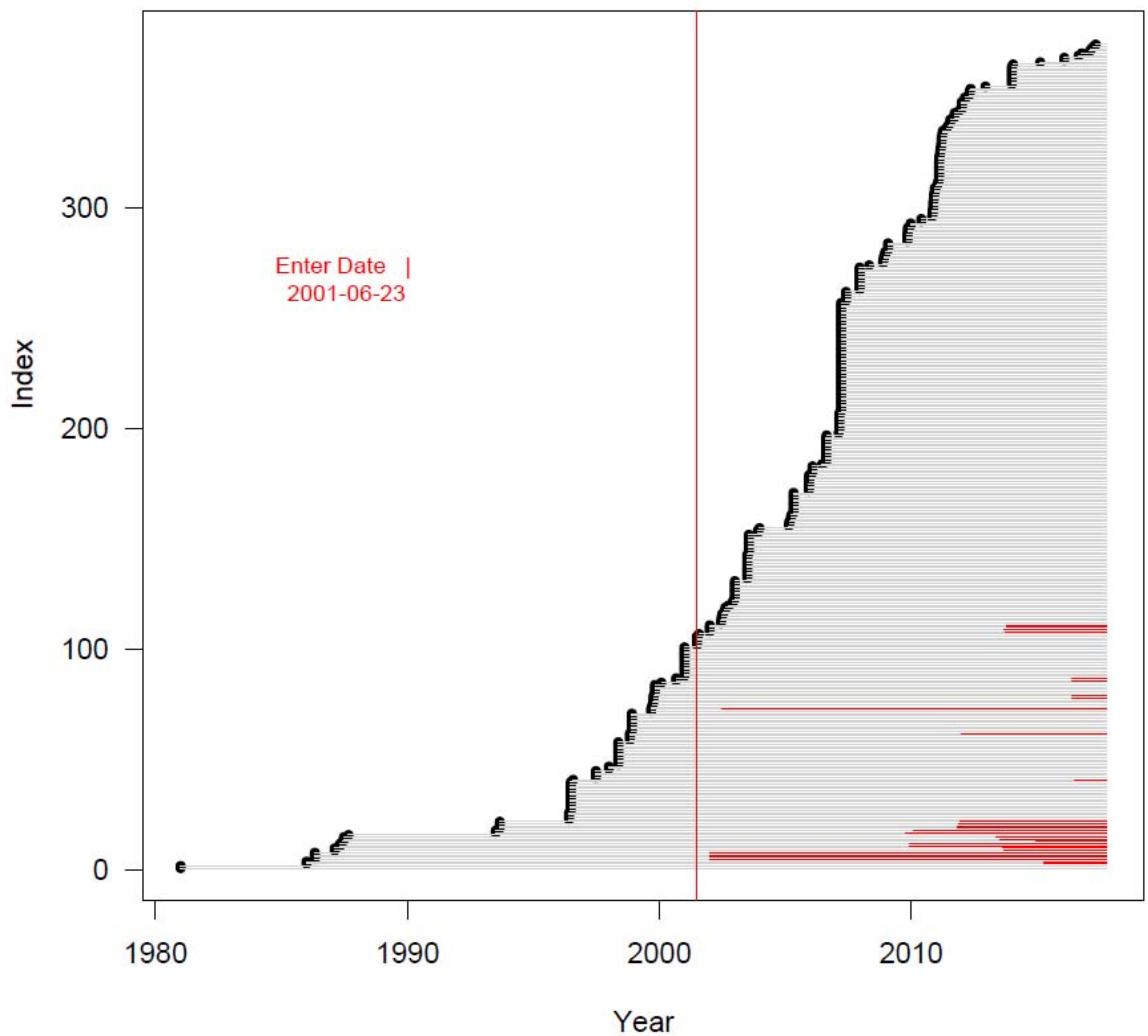

Figure 3-27
Service Eras 13 – 27 kV Vacuum

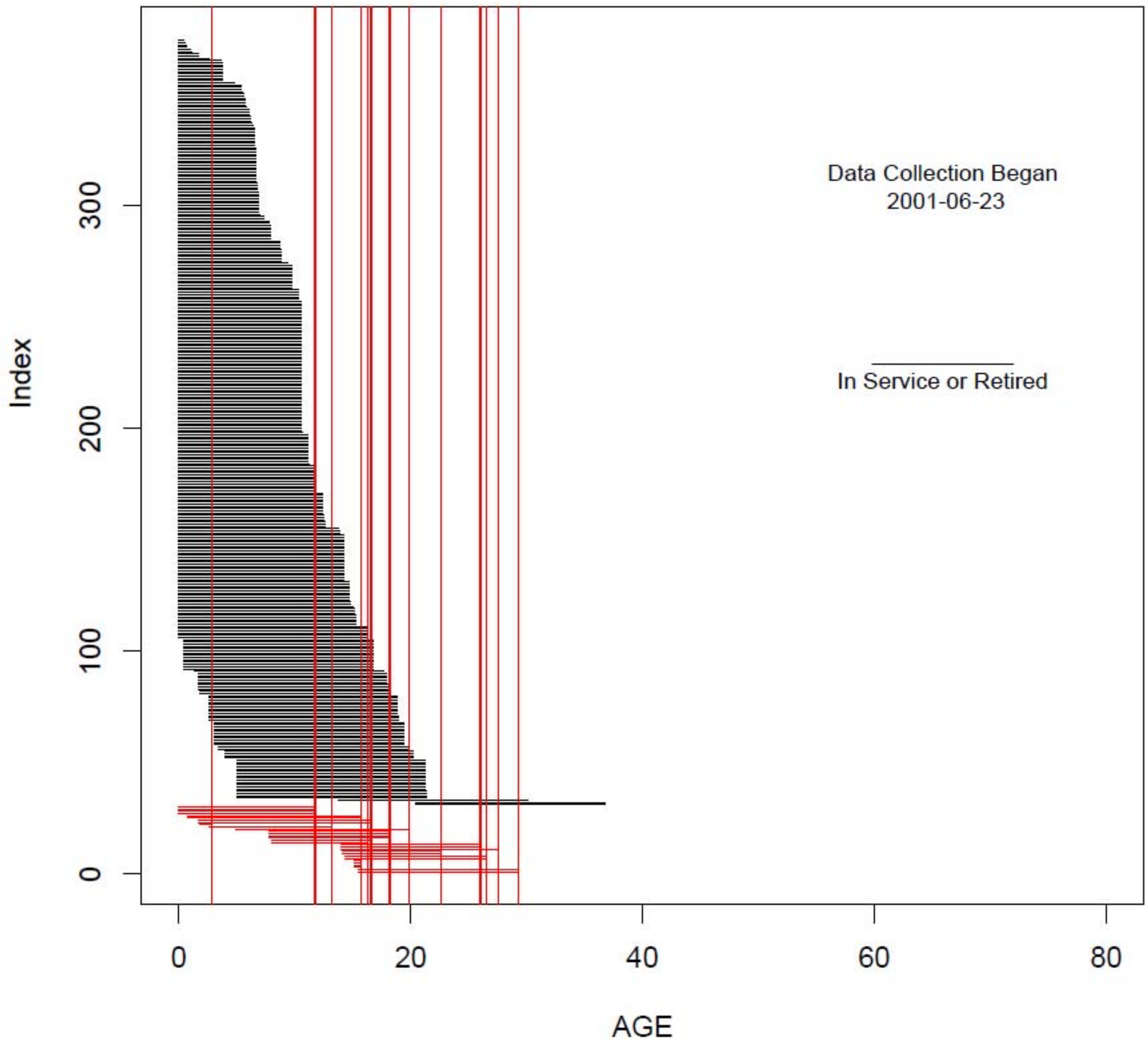

Figure 3-28
Service Ages 13 – 27 kV Vacuum

Removal Hazard Rate 13 – 27 kV Vacuum

Figure 3-29 shows the removal rate developed using the in-service and removed from service data provided for the 13 – 27 kV Vacuum circuit breaker. In the figure, probability of a 40 year old circuit breaker being removed in its next year of life ranges from 12% to 38%. The bands become larger above age 30, reflecting the sparse number of recorded removals in these regions.

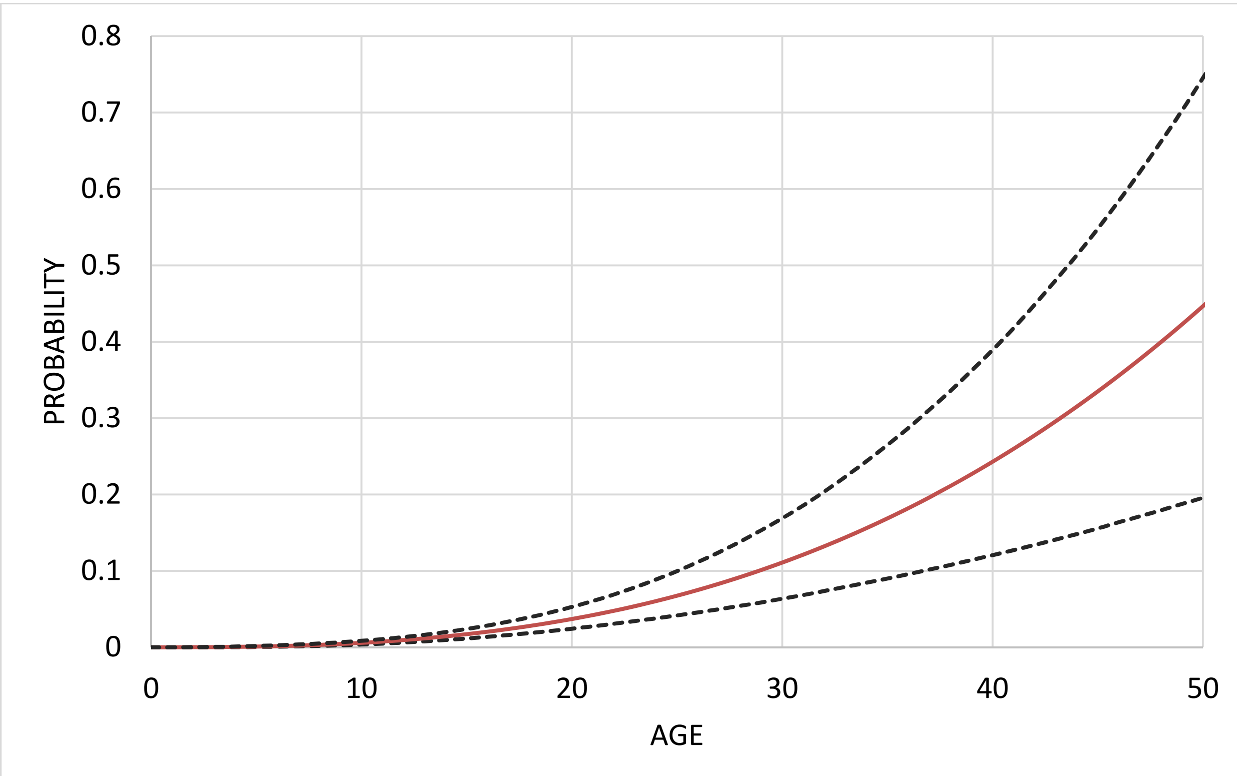

Figure 3-29
Removal Rate 13 – 27 kV Vacuum

Survival Function 13 – 27 kV Vacuum

Figure 3-30 shows the survival function developed using the in-service and removed from service data provided for the 13 – 27 kV Vacuum circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 2% to 22%.

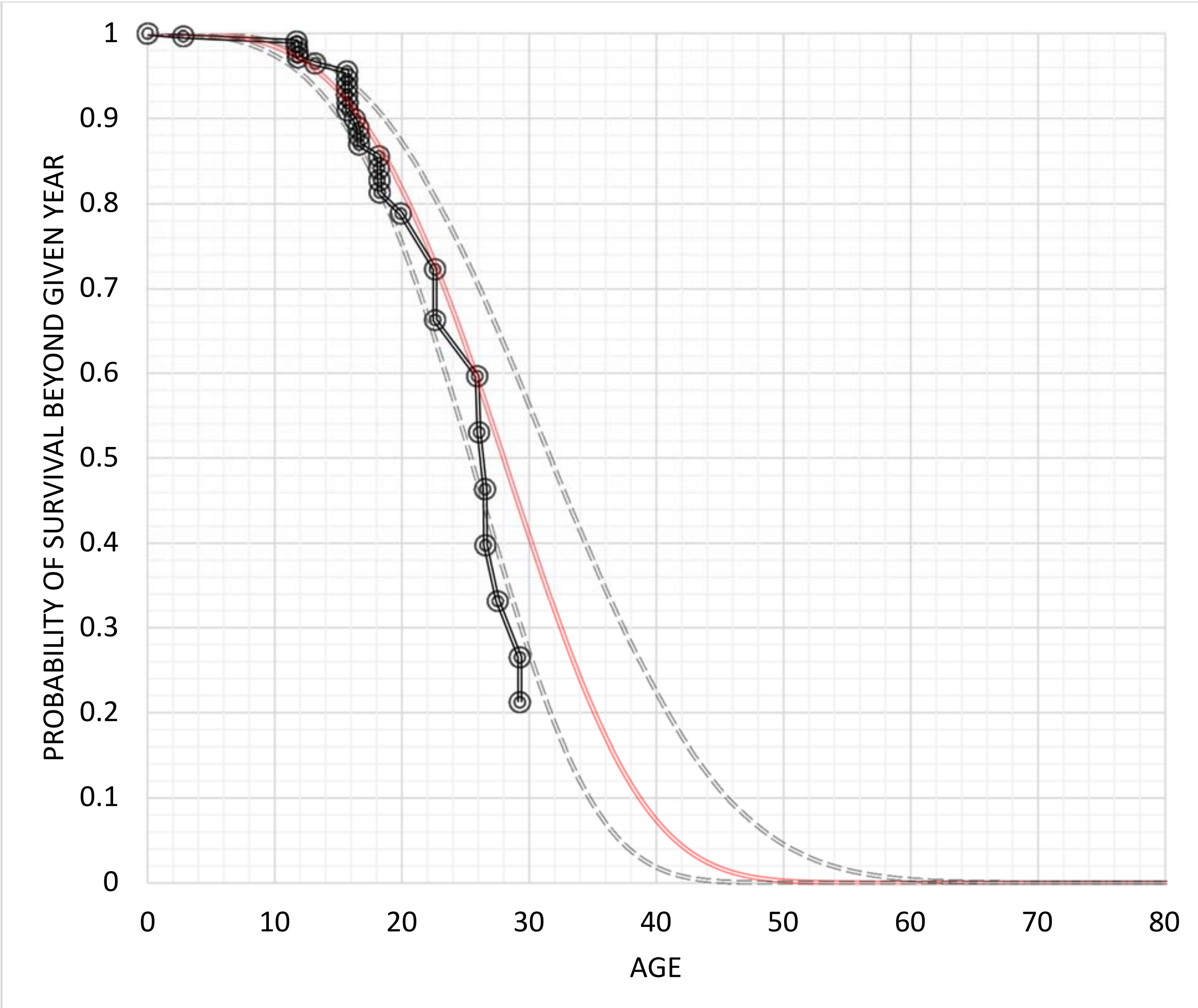

Figure 3-30
Survival Function 13 – 27 kV Vacuum

Forecasting Removals

Figures 3-31 and 3-32 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-31. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 9 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 9 or fewer. Figure 3-32 presents the cumulative results combining each year of the five year period.

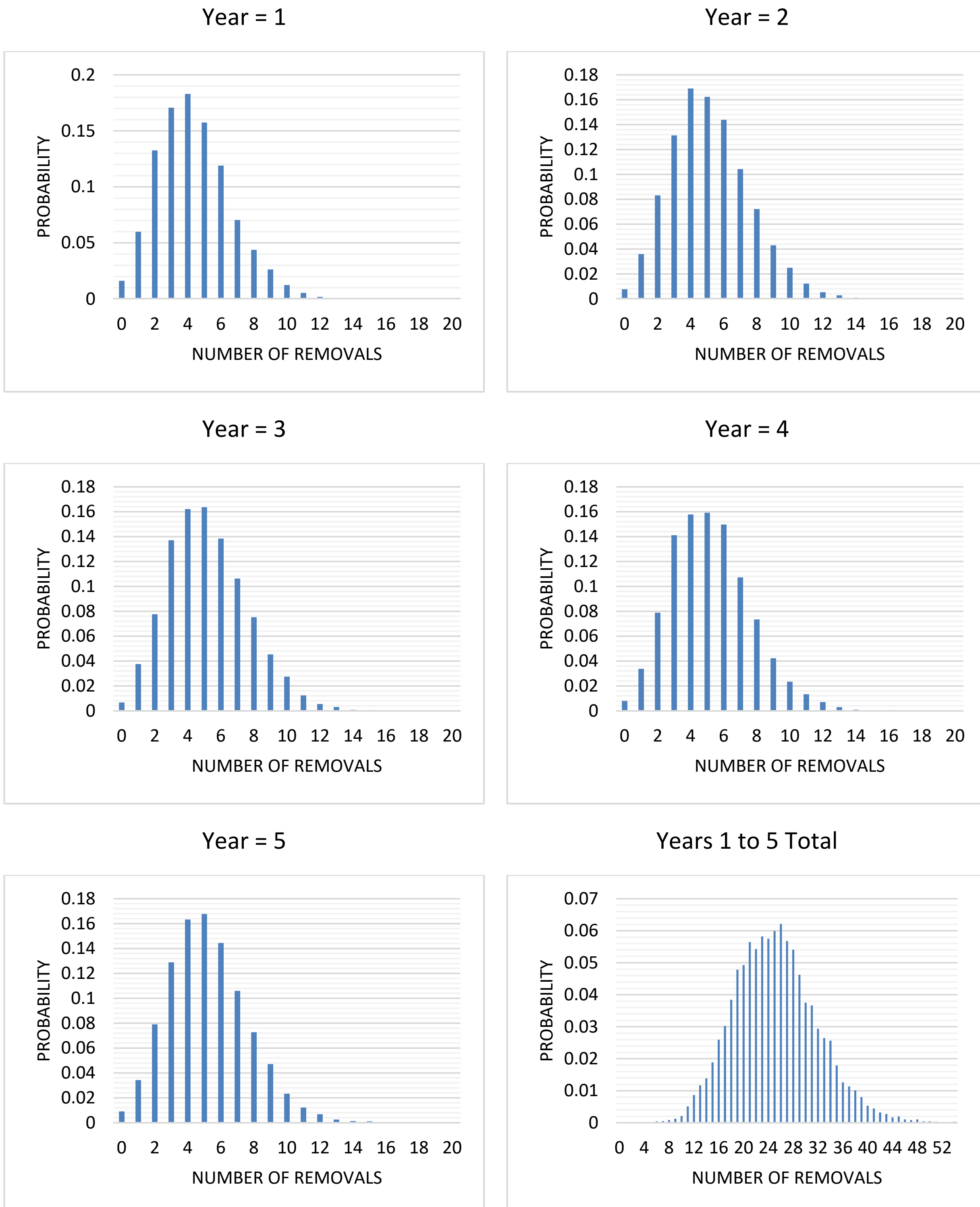

Figure 3-31
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 13 – 27 kV Vacuum

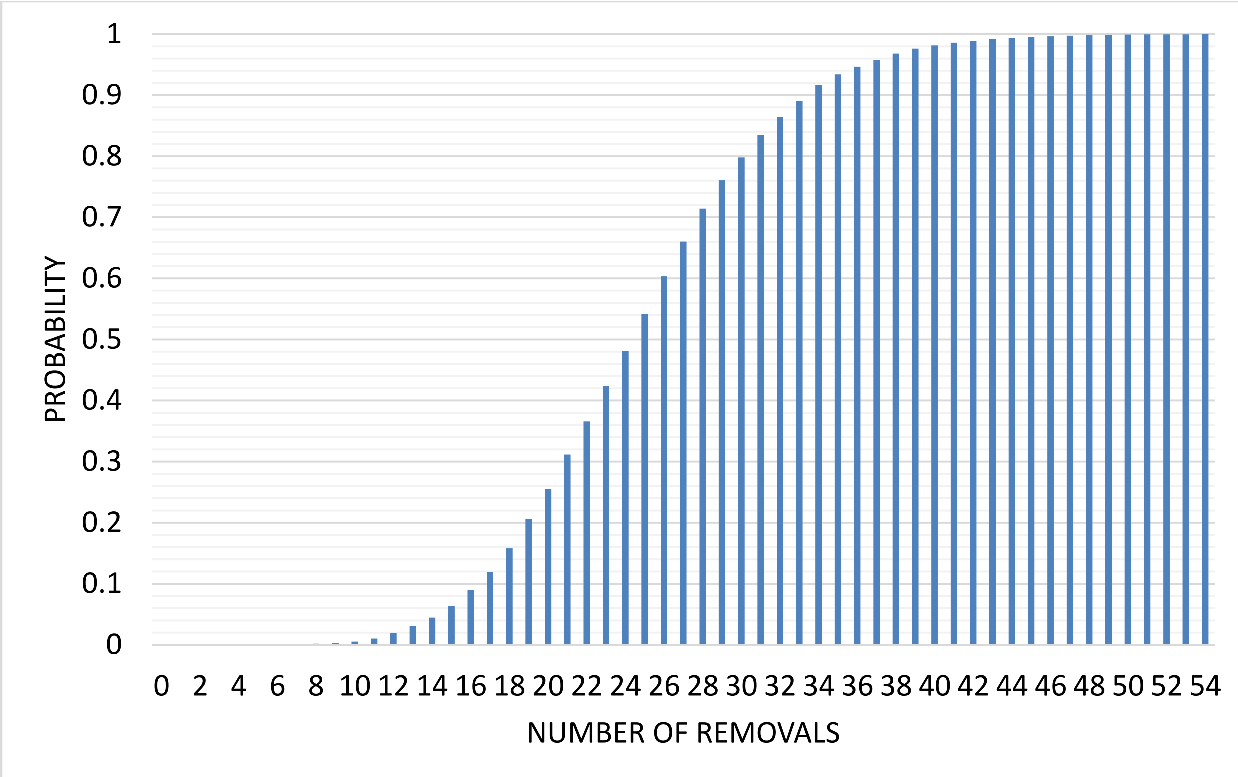

Figure 3-32
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 13 – 27 kV Vacuum

44 kV Gas Removal Analysis

The following provides the results of the 44 kV Gas circuit breaker group analyzed using the method describe in Chapter 2. Table 3-5 shows the number of circuit breakers in-service and removed from service.

Table 3-5
Circuit breaker Group Data 44 kV Gas

Group	In-service	Removed from Service
44 kV Gas	363	40

Age Demographics 44 kV Gas

Figures 3-33 and 3-34 show the age demographics for both in service and removed from service circuit breaker units.

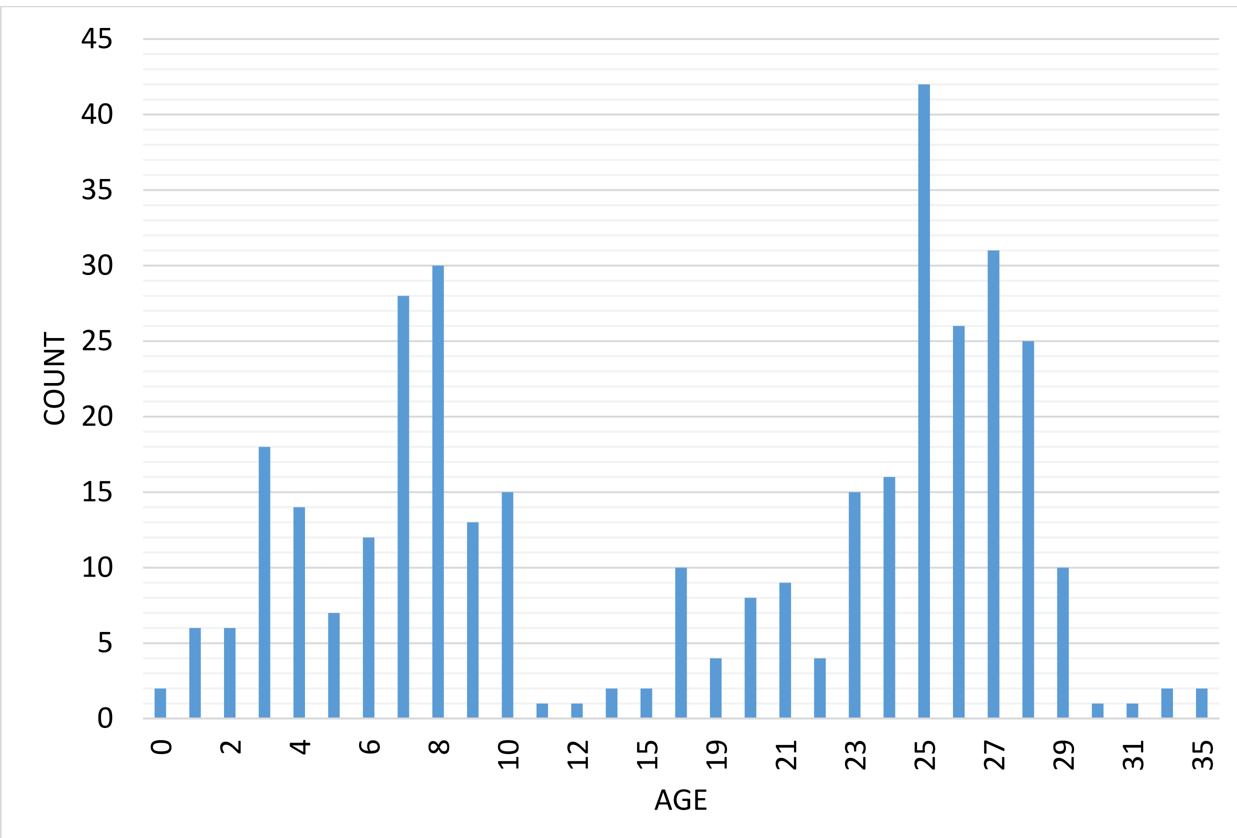

Figure 3-33
Age Demographics In-service 44 kV Gas

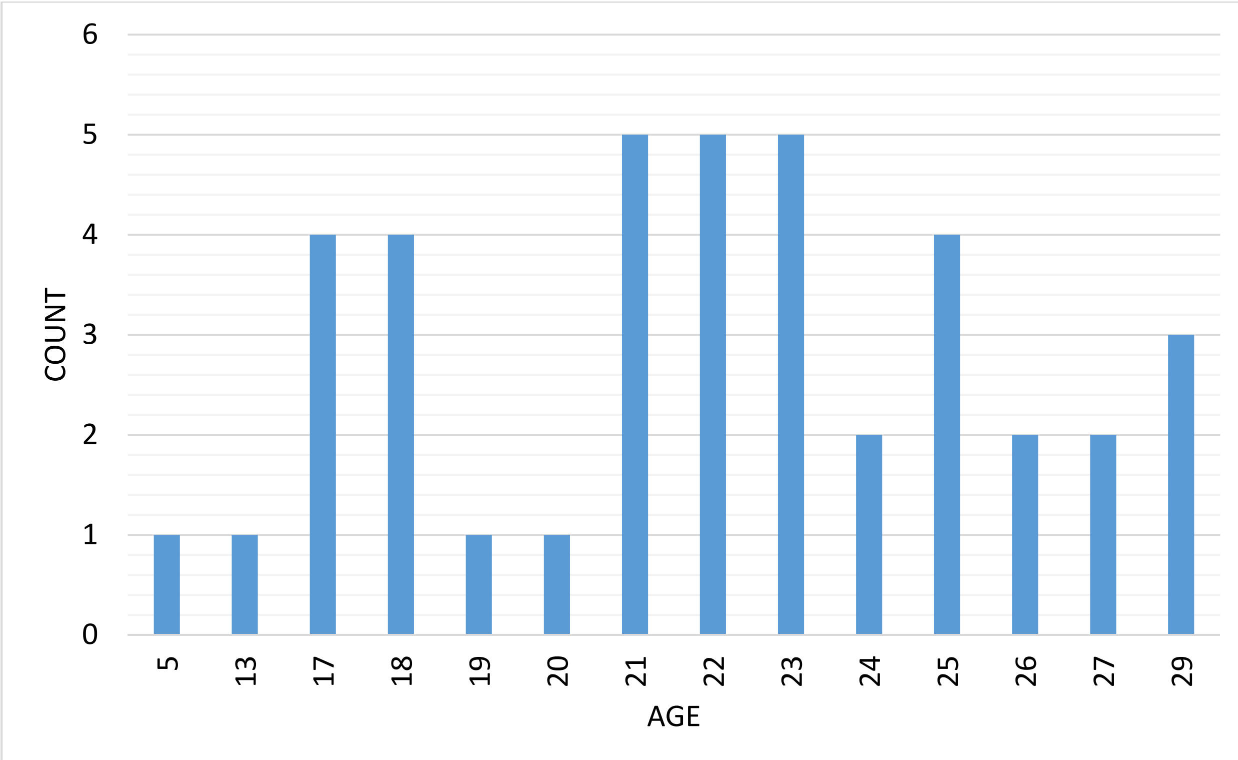

Figure 3-34
Age Demographics Removed From Service 44 kV Gas

Figures 3-35 and 3-36 show the Service Eras and Service Ages of the 44 kV Gas circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1999.

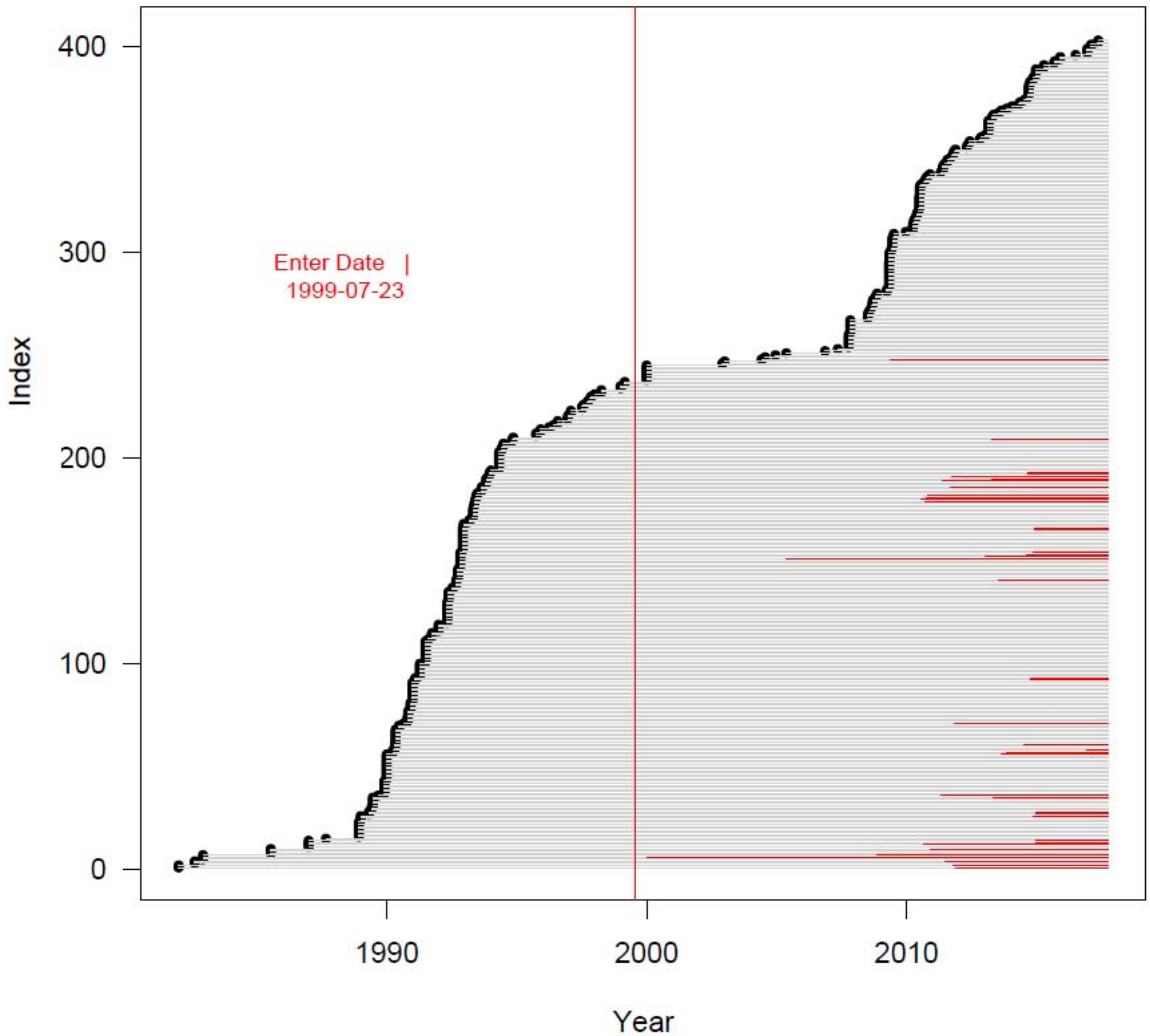

Figure 3-35
Service Eras 44 kV Gas

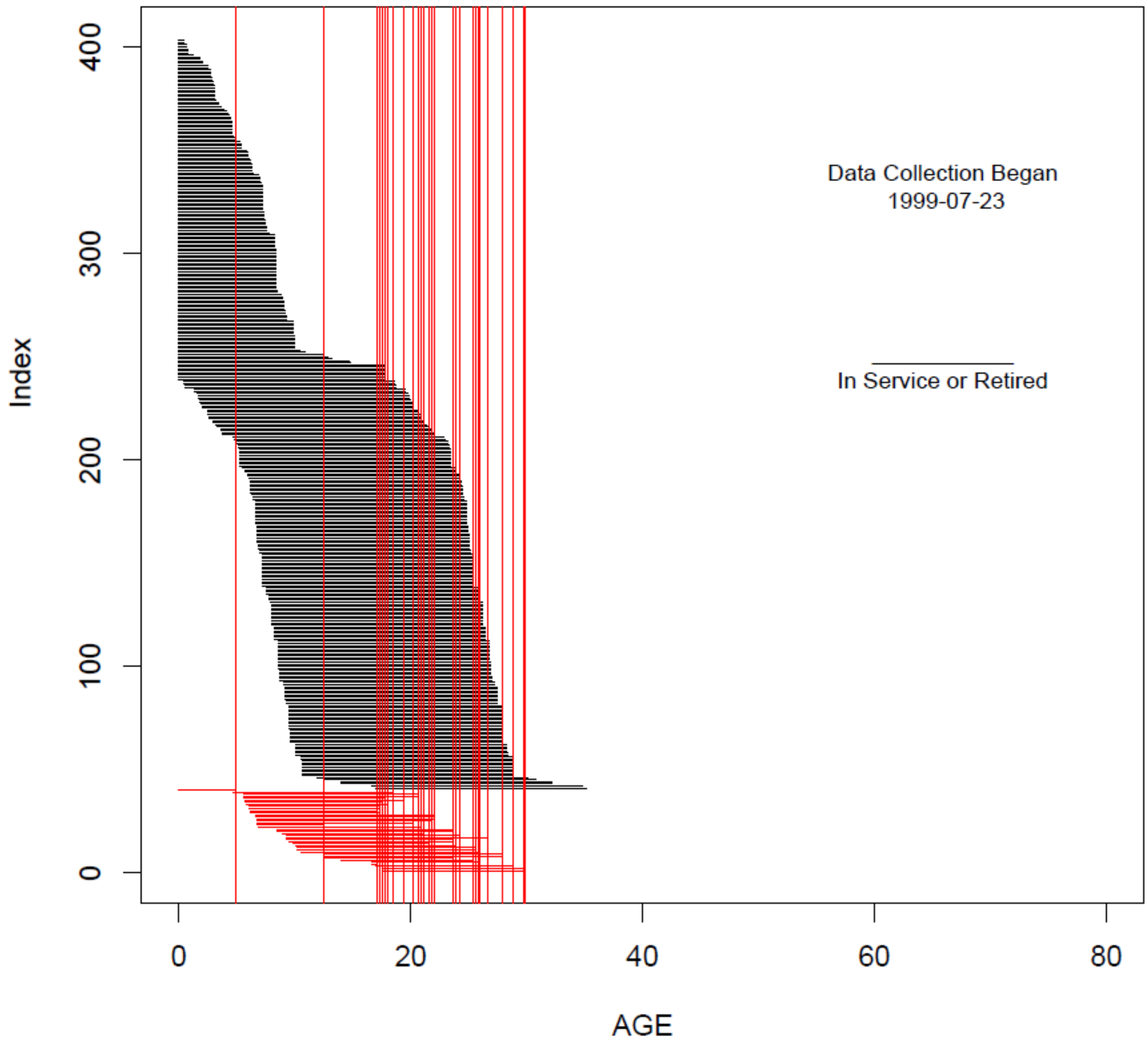

Figure 3-36
Service Ages 44 kV Gas

Removal Hazard Rate 44 kV Gas

Figure 3-37 shows the removal rate developed using the in-service and removed from service data provided for the 44 kV Gas circuit breaker. In the figure, probability of a 40 year old circuit breaker being removed in its next year of life ranges from 4.1% to 11%. For a 60 year old circuit breaker the probability of being removed in its next year of life ranges from 9.3% to 38%. Note the 95% confidence intervals. The bands become larger above age 40, reflecting the sparse number of recorded removals in these regions.

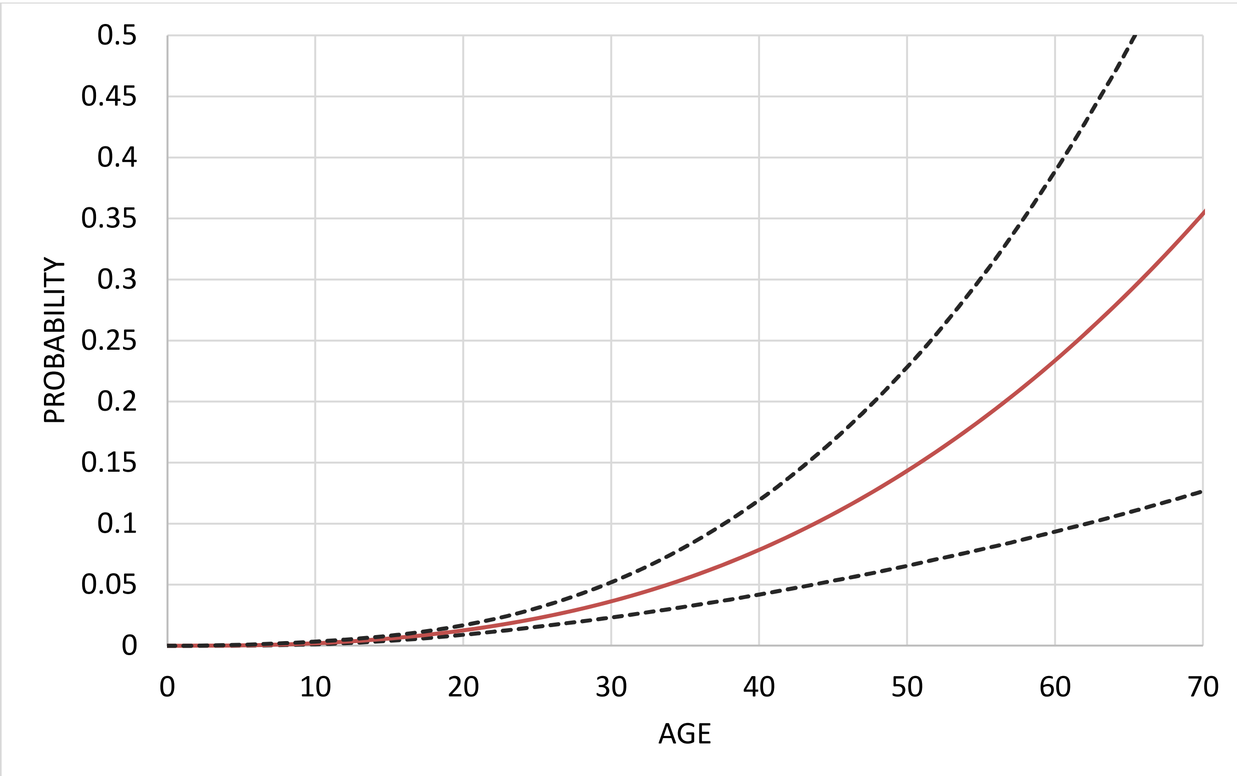

Figure 3-37
Removal Rate 44 kV Gas

Survival Function 44 kV Gas

Figure 3-38 shows the survival function developed using the in-service and removed from service data provided for the 44 kV Gas circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 29% to 57%.

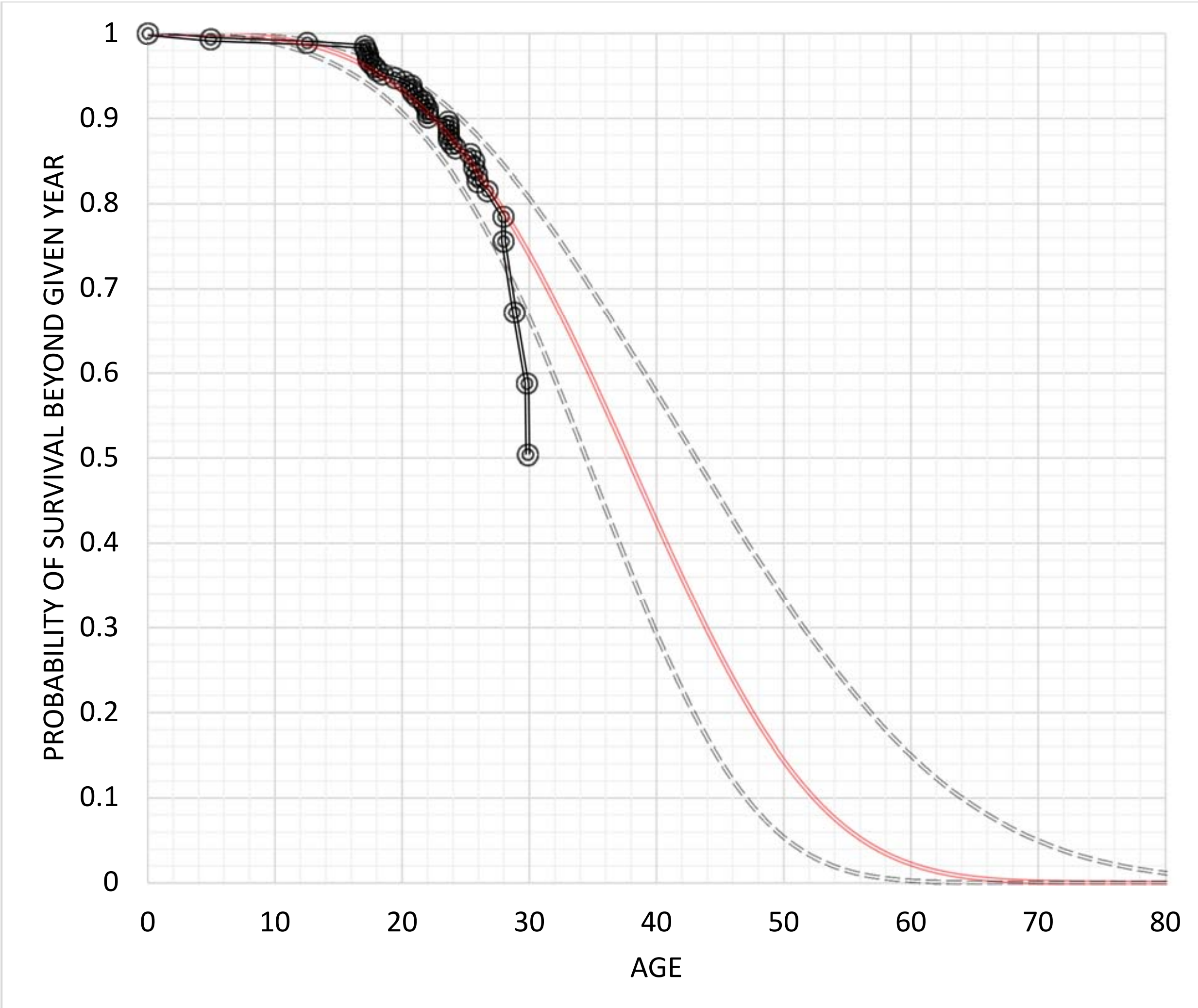

Figure 3-38
Survival Function 44 kV Gas

Forecasting Removals

Figures 3-39 and 3-40 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-39. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 11 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 11 or fewer. Figure 3-40 presents the cumulative results combining each year of the five year period.

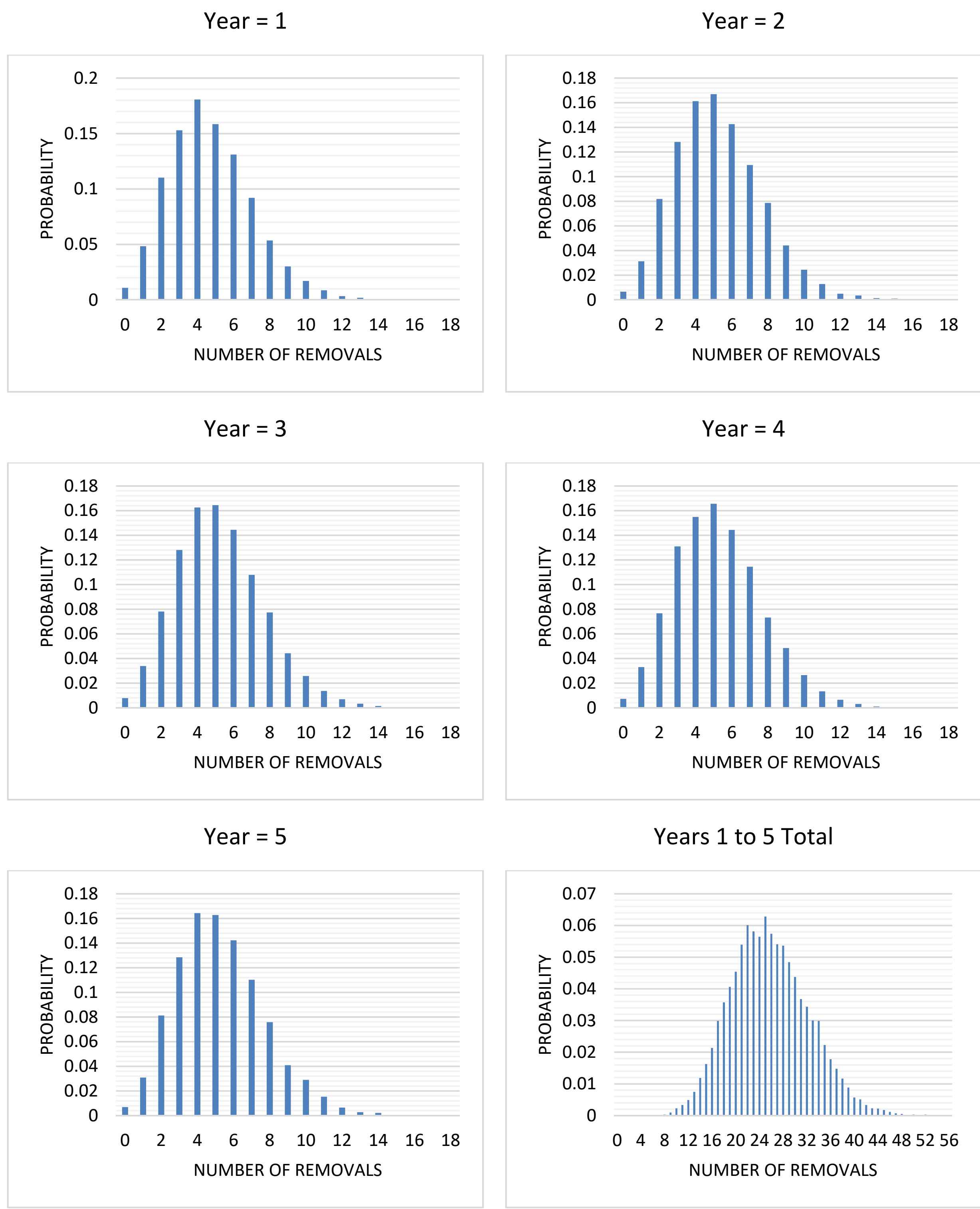

Figure 3-39
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 44 kV Gas

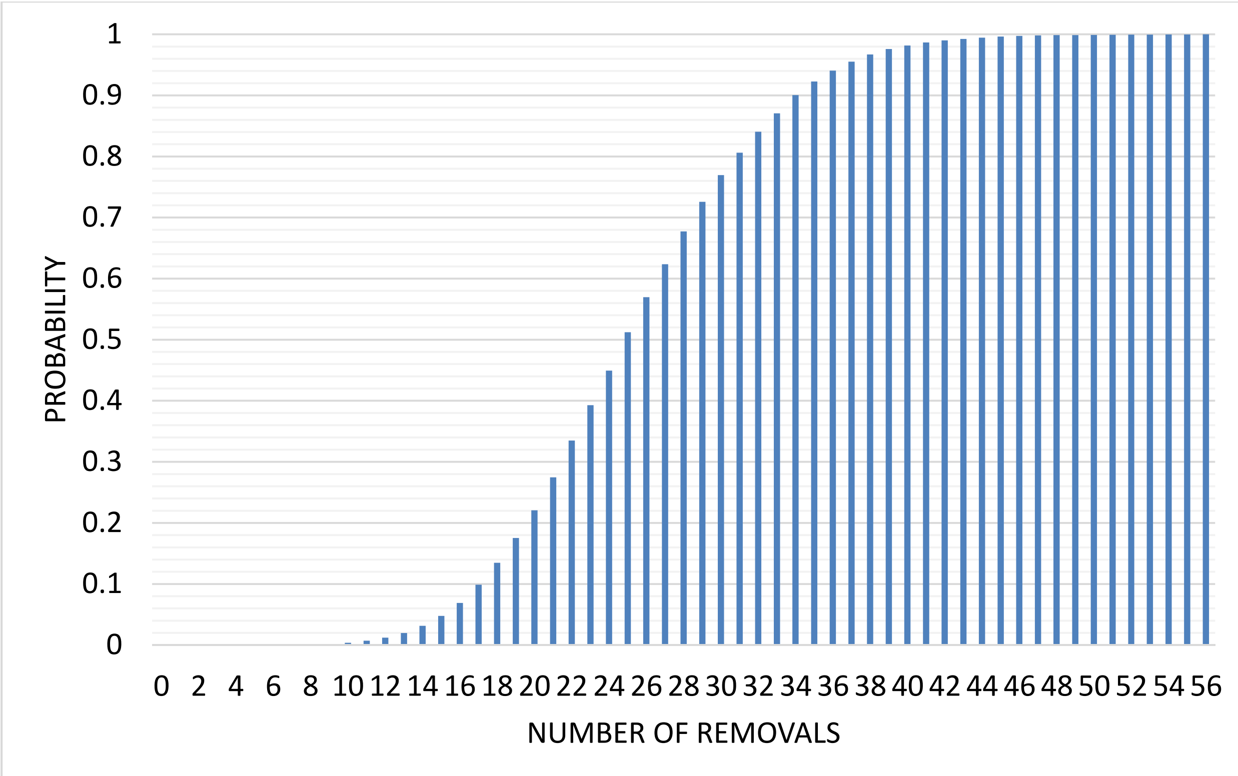

Figure 3-40
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 44 kV Gas

44 kV Oil Removal Analysis

The following provides the results of the 44 kV Oil circuit breaker group analyzed using the method describe in Chapter 2. Table 3-6 shows the number of circuit breakers in-service and removed from service.

Table 3-6
Circuit breaker Group Data 44 kV Oil

Group	In-service	Removed from Service
44 kV Oil	443	77

Age Demographics 44 kV Oil

Figures 3-41 and 3-42 show the age demographics for both in service and removed from service circuit breaker units.

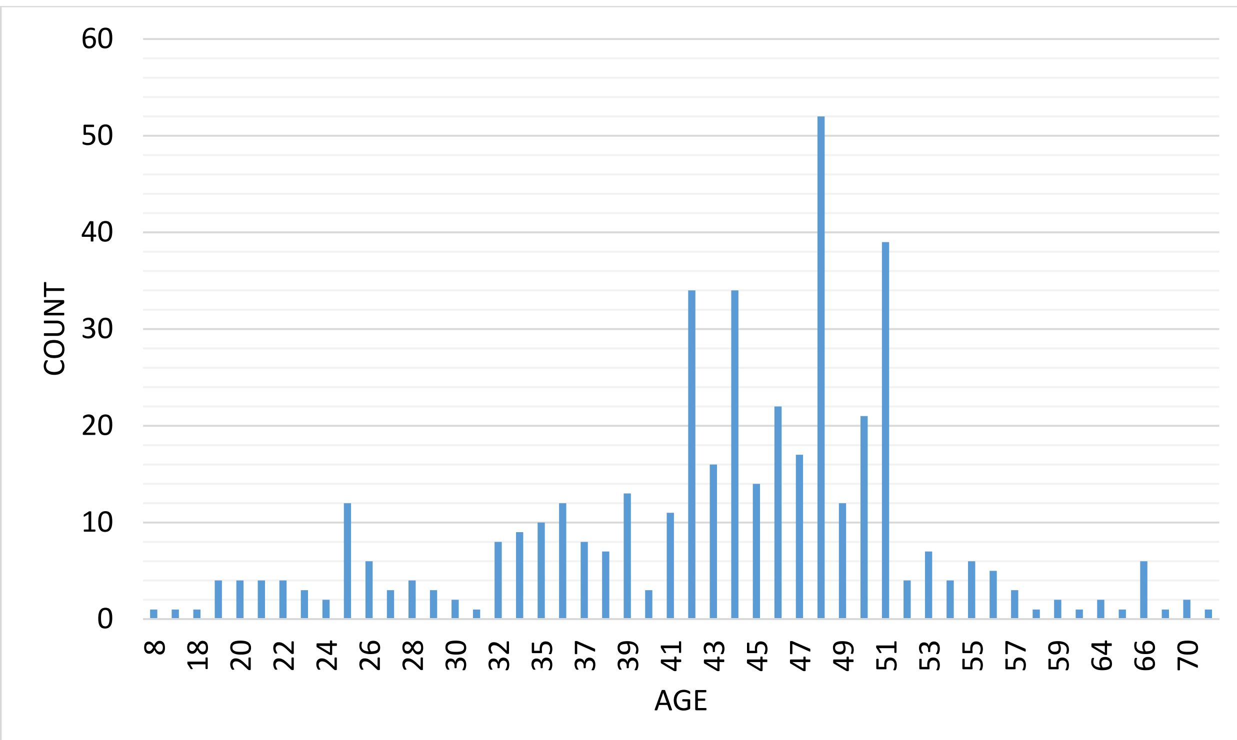

Figure 3-41
Age Demographics In-service 44 kV Oil

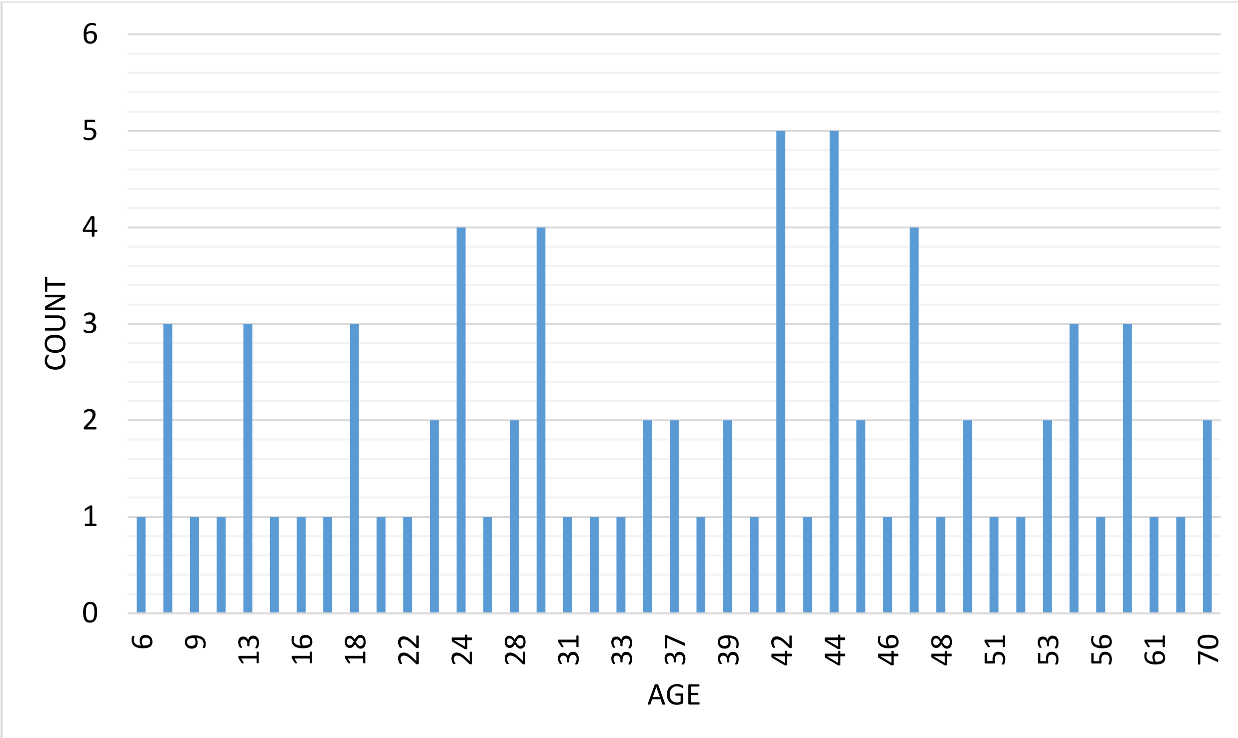

Figure 3-42
Age Demographics Removed From Service 44 kV Oil

Figures 3-43 and 3-44 show the Service Eras and Service Ages of the 44 kV Oil circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1982.

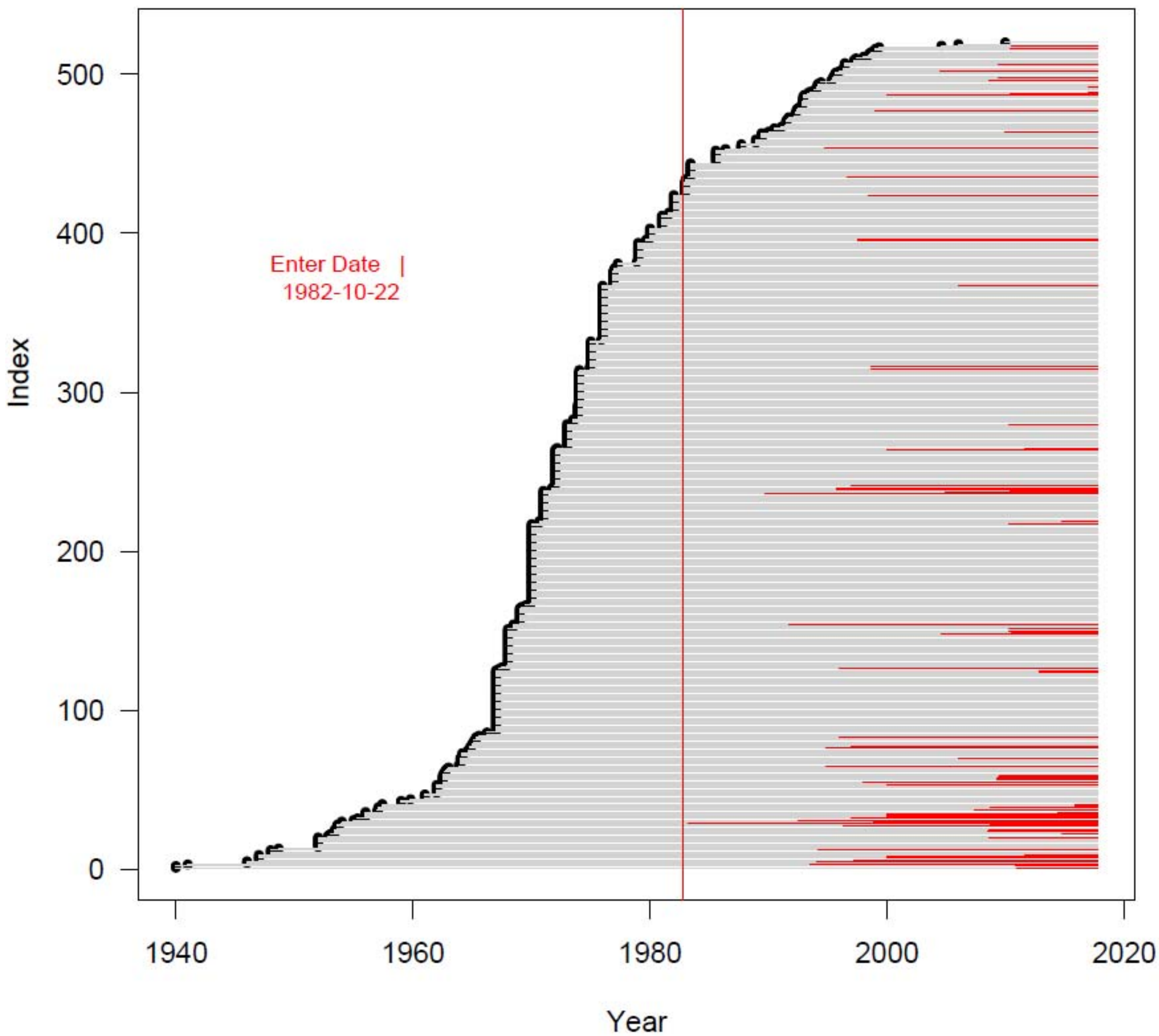

Figure 3-43
Service Eras 44 kV Oil

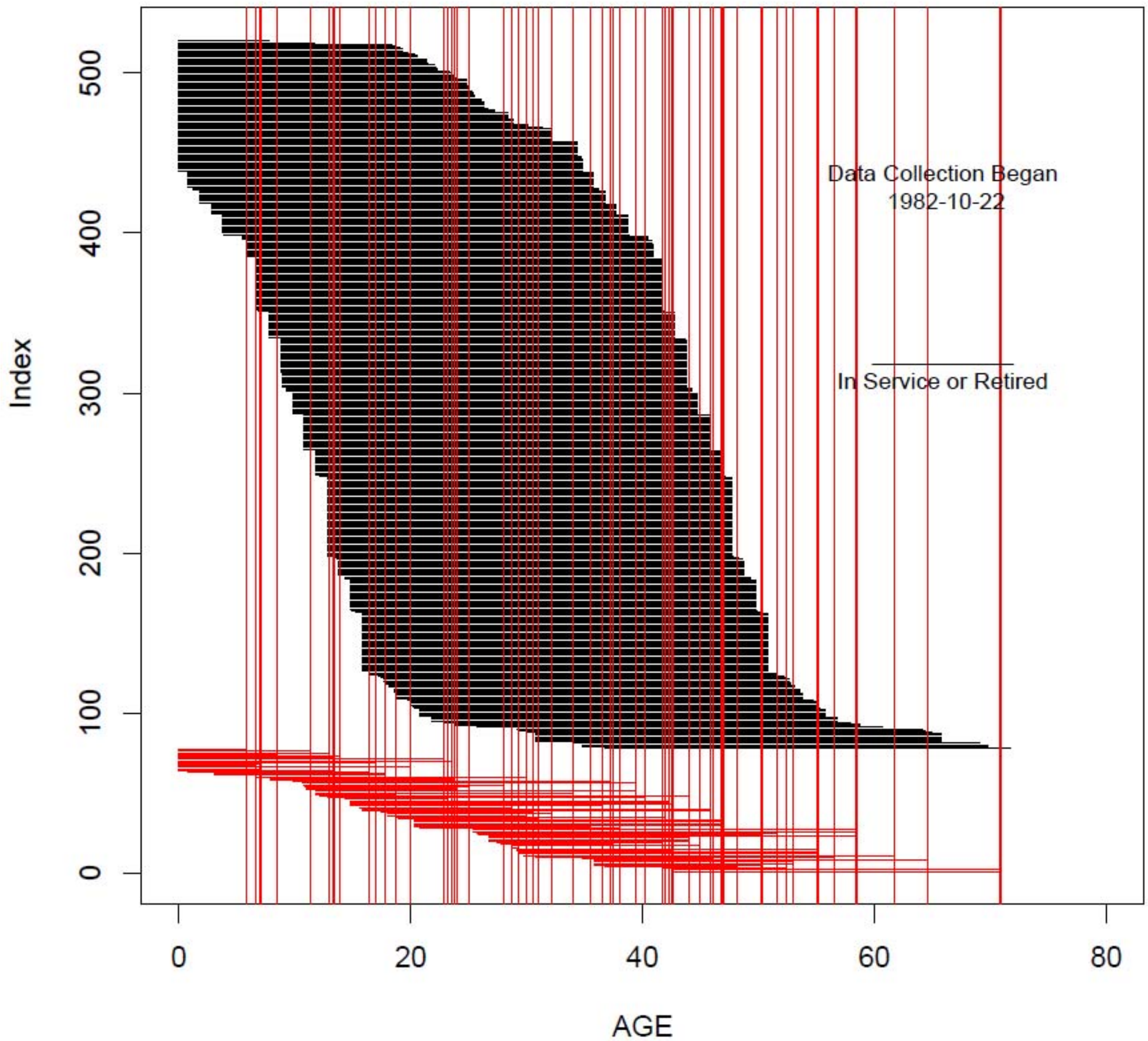

Figure 3-44
Service Ages 44 kV Oil

Removal Hazard Rate 44 kV Oil

Figure 3-45 shows the removal rate developed using the in-service and removed from service data provided for the 44 kV Oil circuit breaker. In the figure, probability of a 40 year old circuit breaker being removed in its next year of life ranges from 0.5% to 0.8%. For a 60 year old circuit breaker the probability of being removed in its next year of life ranges from 0.6% to 1.6%. Note the 95% confidence intervals. The bands become larger above age 60, reflecting the sparse number of recorded removals in these regions.

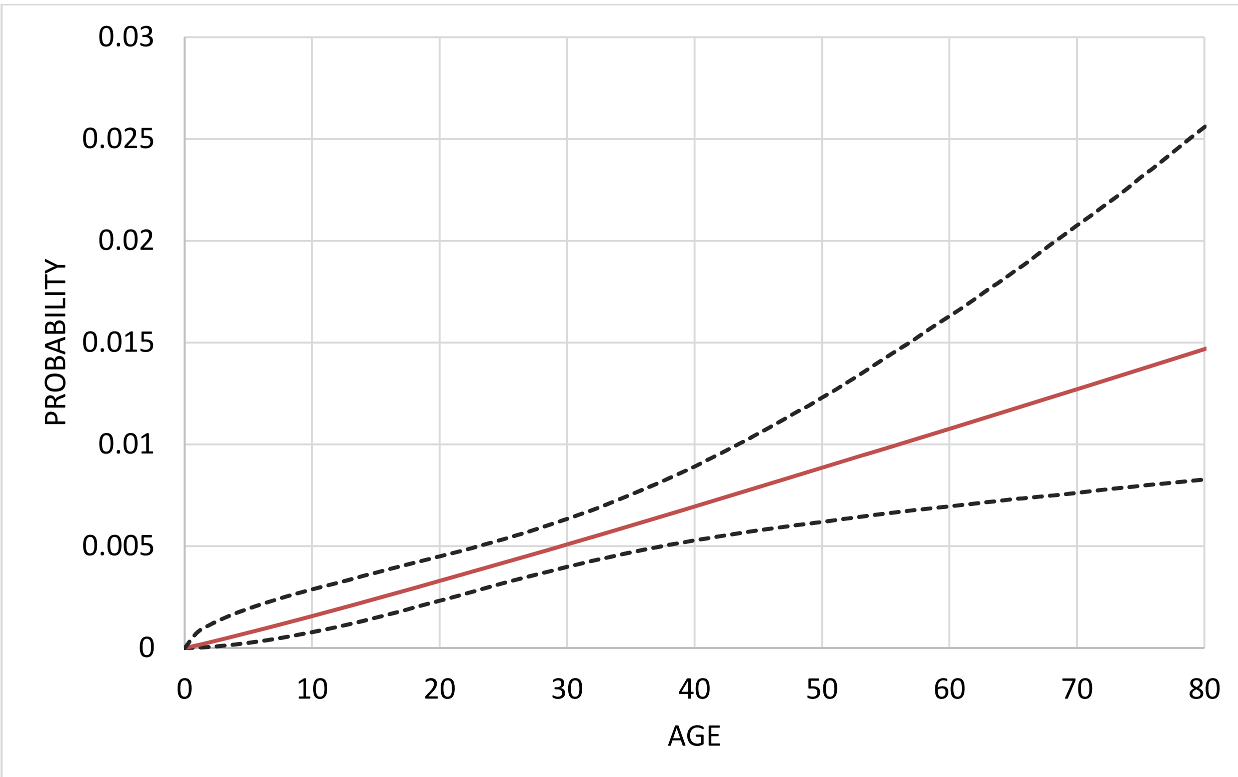

Figure 3-45
Removal Rate 44 kV Oil

Survival Function 44 kV Oil

Figure 3-46 shows the survival function developed using the in-service and removed from service data provided for the 44 kV Oil r circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 84% to 90%.

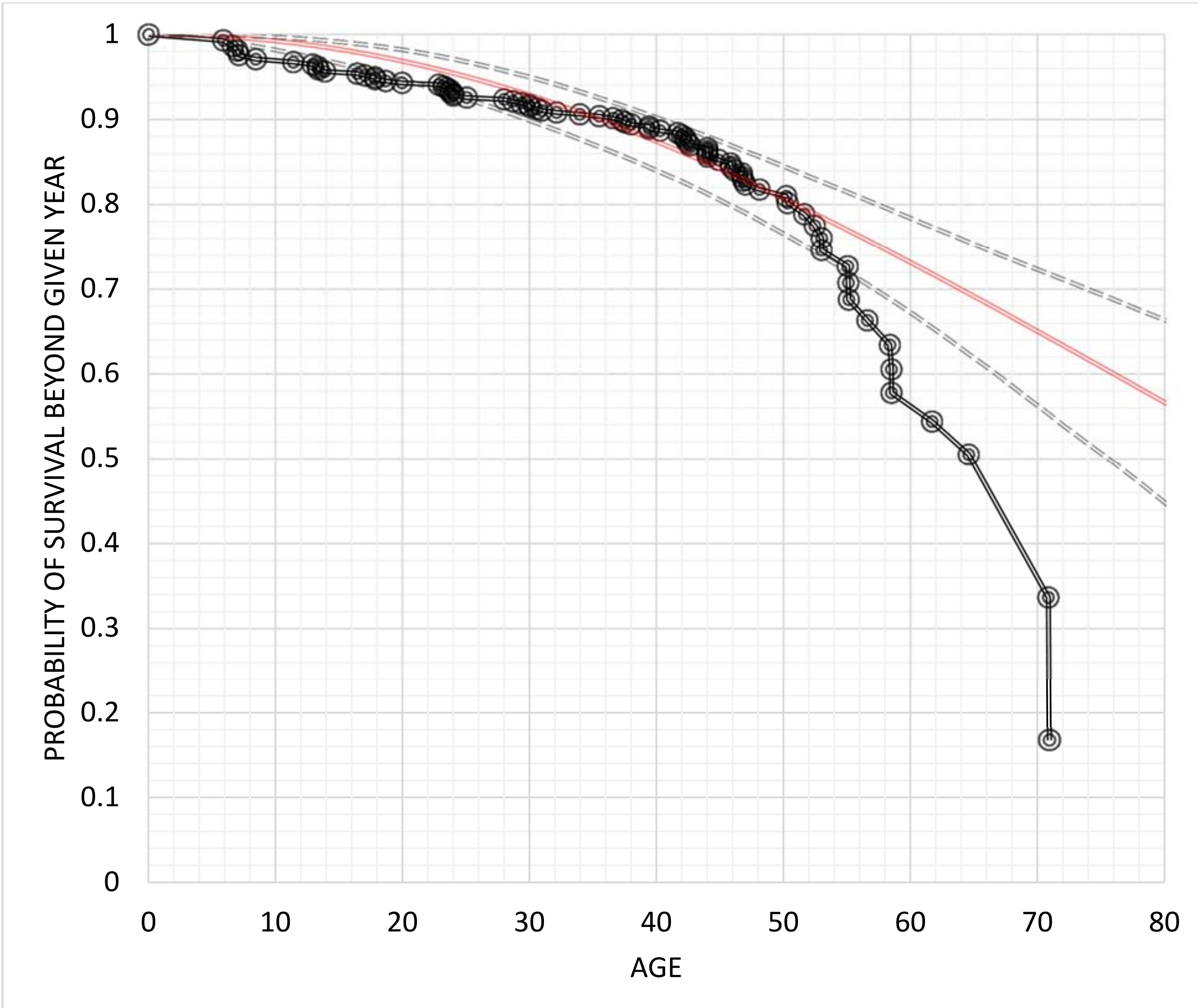

Figure 3-46
Survival Function 44 kV Oil

Forecasting Removals

Figures 3-47 and 3-48 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-48. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 8 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 8 or fewer. Figure 3-48 presents the cumulative results combining each year of the five year period.

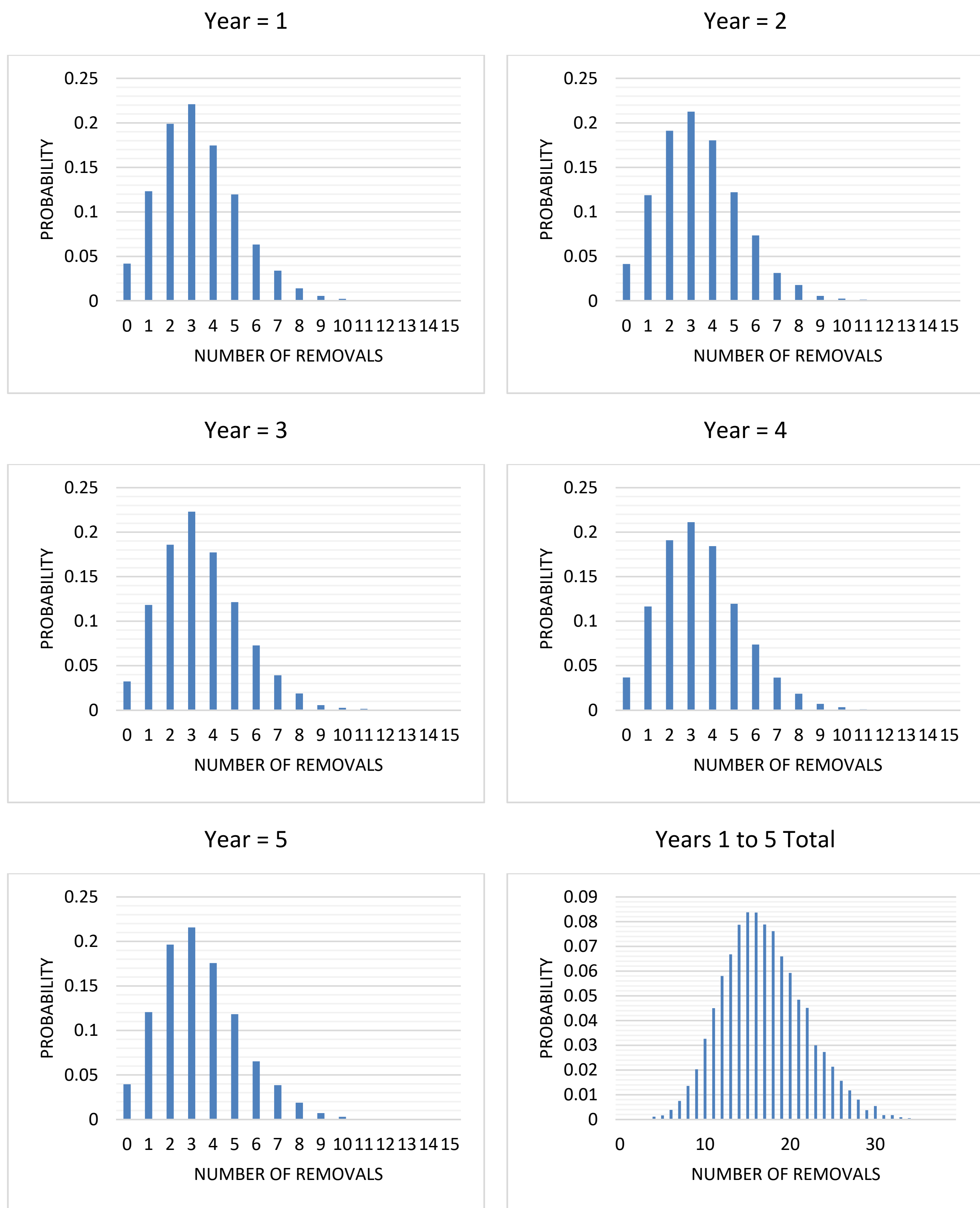

Figure 3-47
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 44 kV Oil

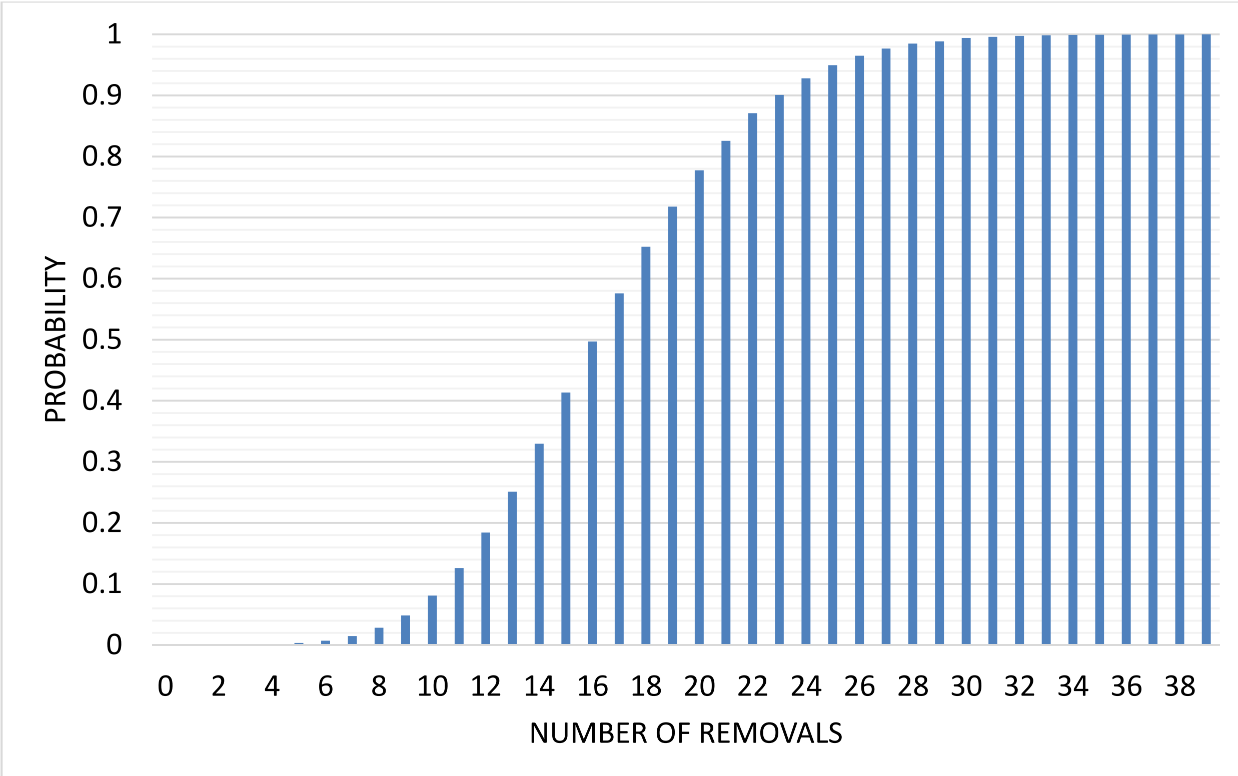

Figure 3-48
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 44 kV Oil

115 kV Gas Removal Analysis

The following provides the results of the 115 kV Gas circuit breaker group analyzed using the method describe in Chapter 2. Table 3-7 shows the number of circuit breakers in-service and removed from service.

Table 3-7
Circuit breaker Group Data 115 kV Gas

Group	In-service	Removed from Service
115 kV Gas	308	33

Age Demographics 115 kV Gas

Figures 3-49 and 3-50 show the age demographics for both in service and removed from service circuit breaker units.

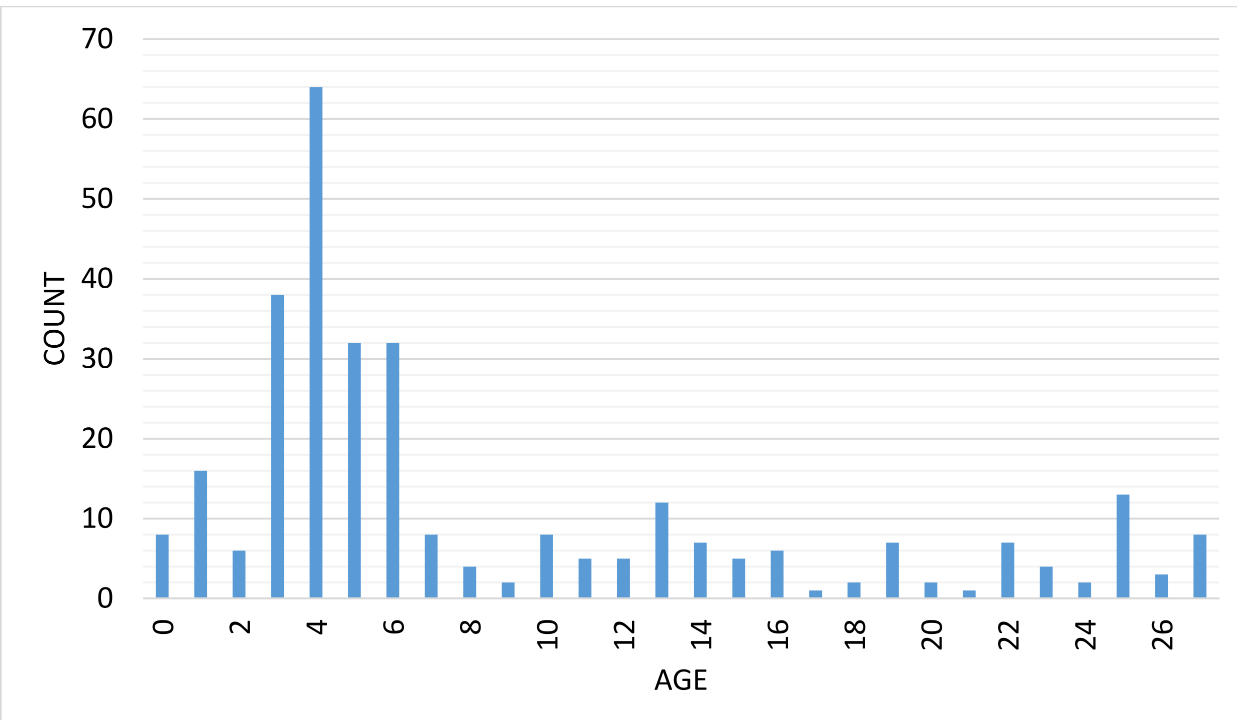

Figure 3-49
Age Demographics In-service 115 kV Gas

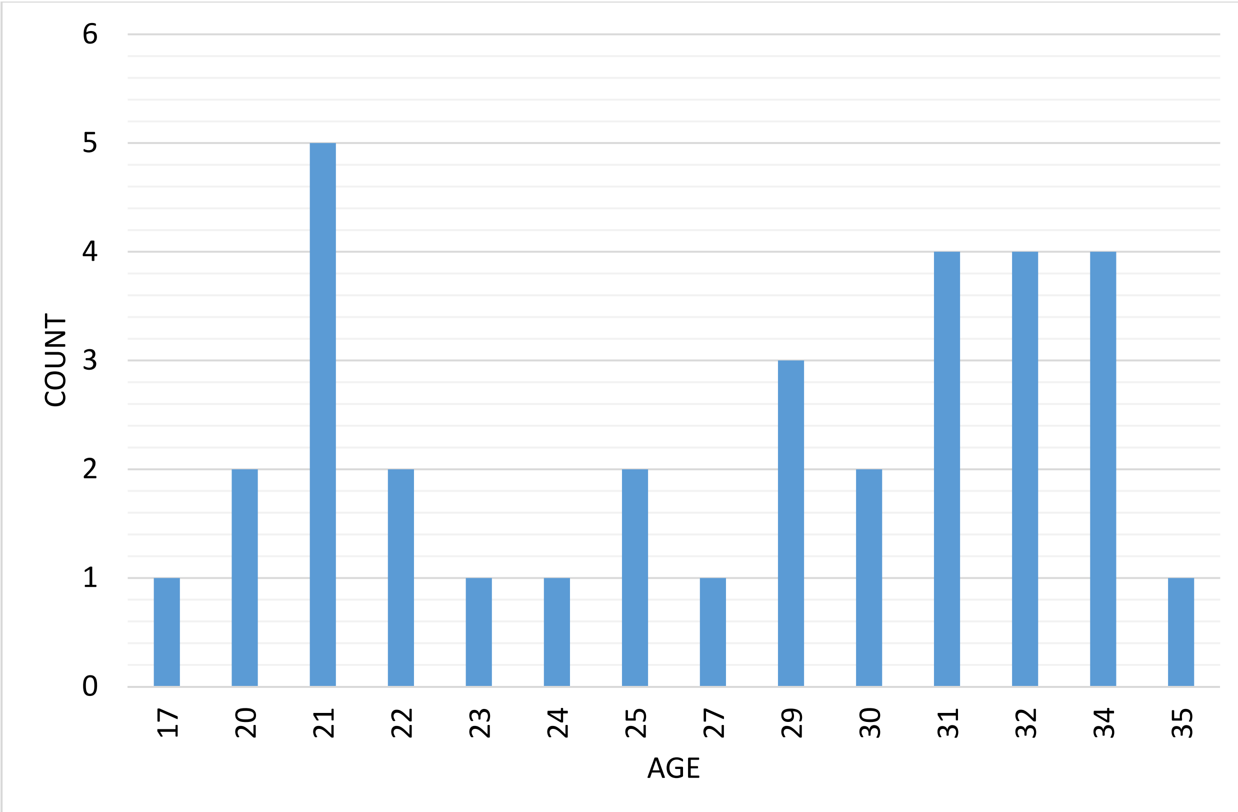

Figure 3-50
Age Demographics Removed From Service 115 kV Gas

Figures 3-51 and 3-52 show the Service Eras and Service Ages of the 115 kV Gas circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1999.

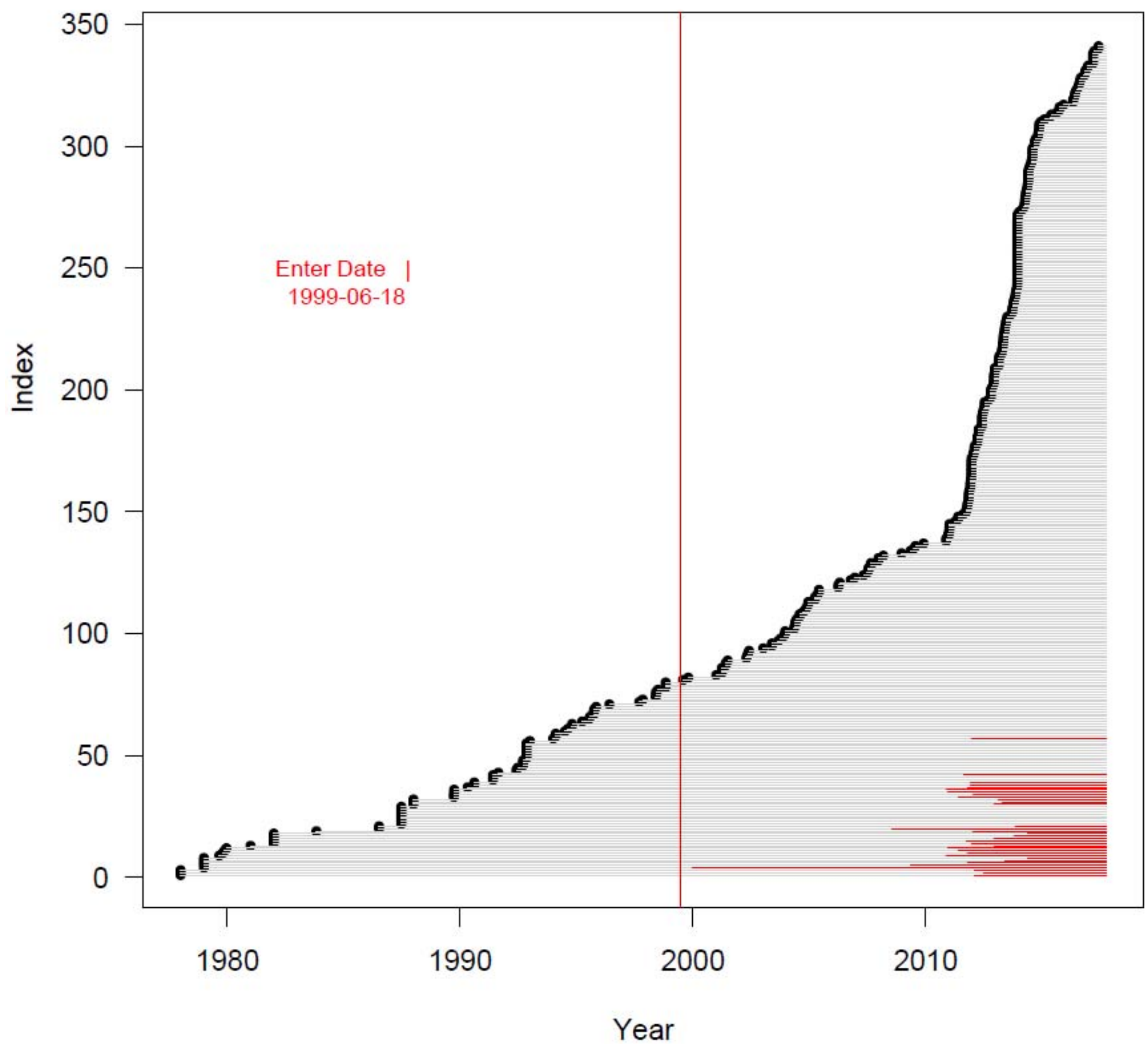

Figure 3-51
Service Eras 115 kV Gas

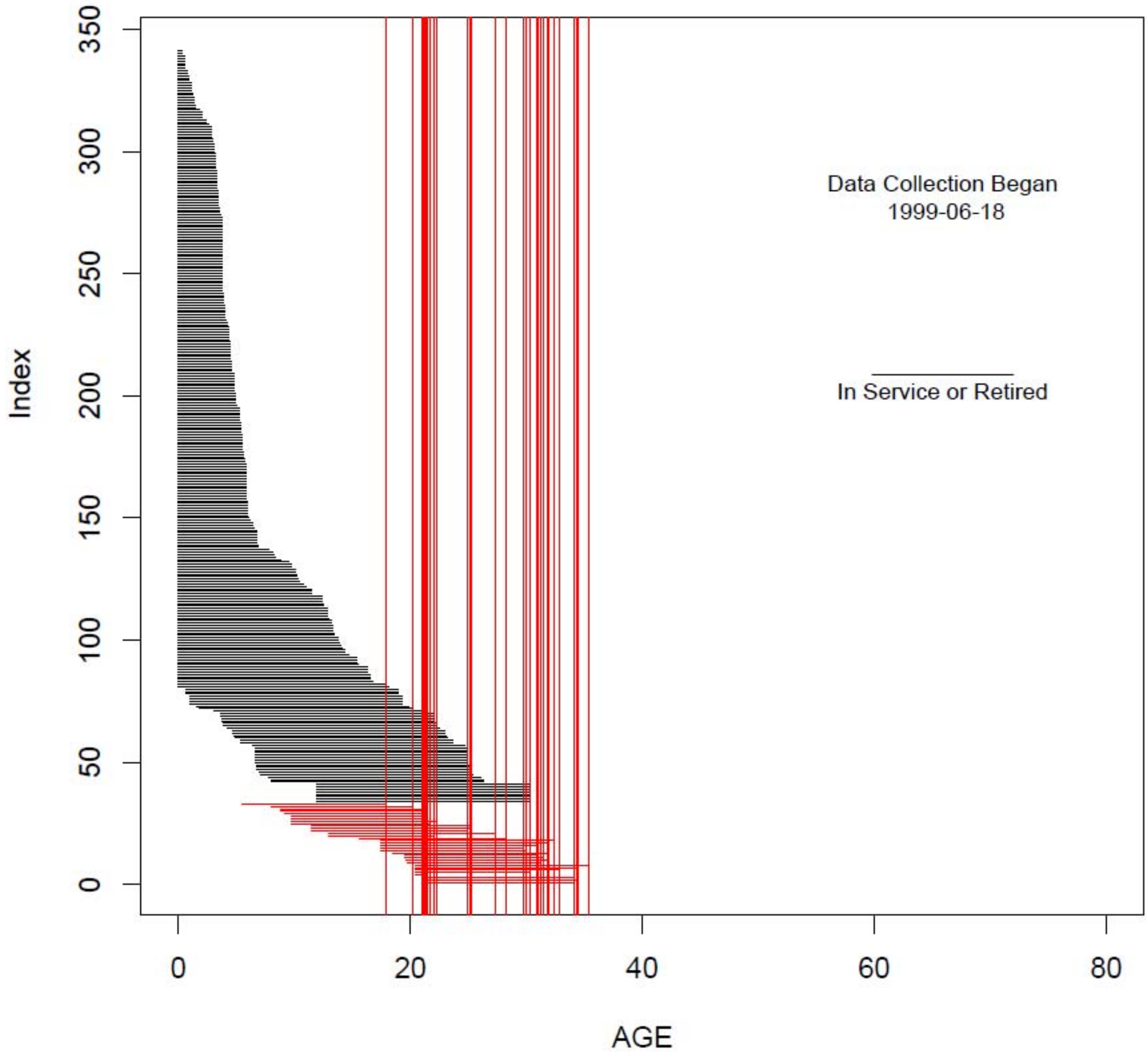

Figure 3-52
Service Ages 115 kV Gas

Removal Hazard Rate 115 kV Gas

Figure 3-53 shows the removal rate developed using the in-service and removed from service data provided for the 115 kV Gas circuit breaker. In the figure, probability of a 40 year old circuit breaker being removed in its next year of life ranges from 12% to 26%. For a 50 year old circuit breaker the probability of being removed in its next year of life ranges from 23% to 51%. Note the 95% confidence intervals. The bands become larger above age 50, reflecting the sparse number of recorded removals in these regions.

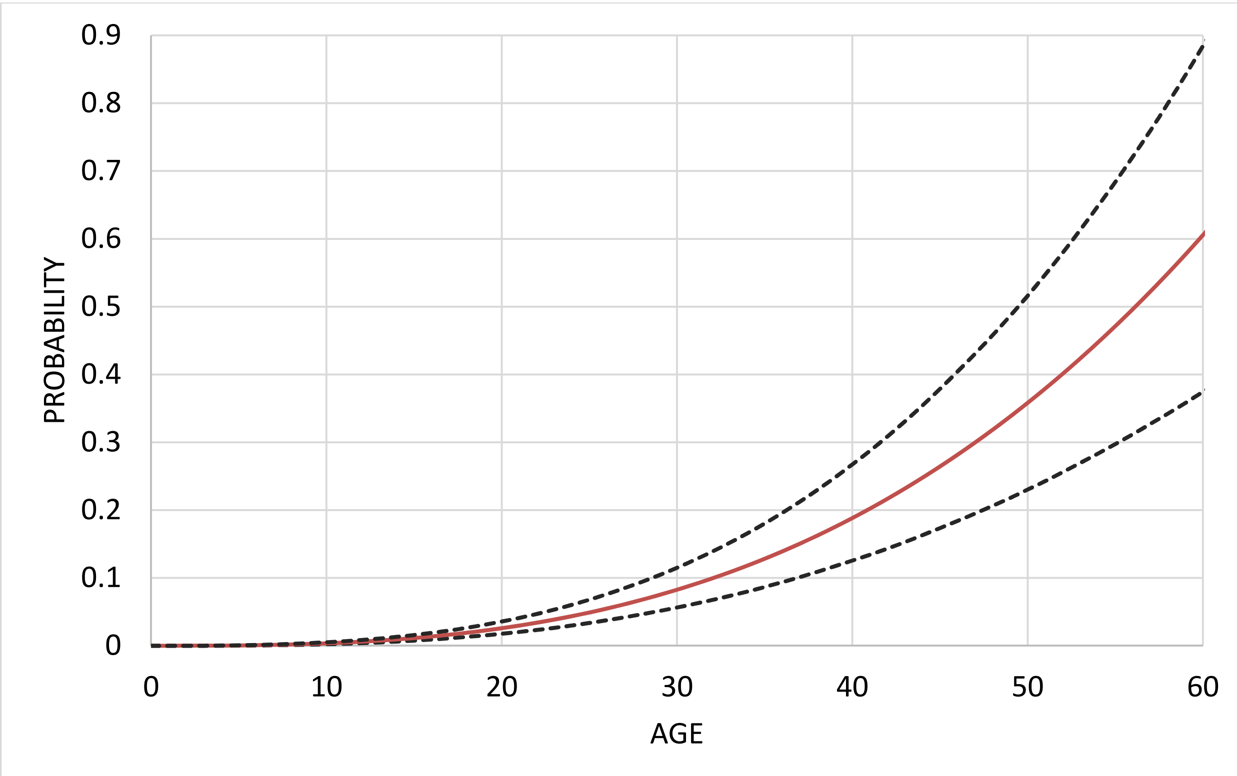

Figure 3-53
Removal Rate 115 kV Gas

Survival Function 115 kV Gas

Figure 3-54 shows the survival function developed using the in-service and removed from service data provided for the 115 kV Gas circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 6.5% to 26%.

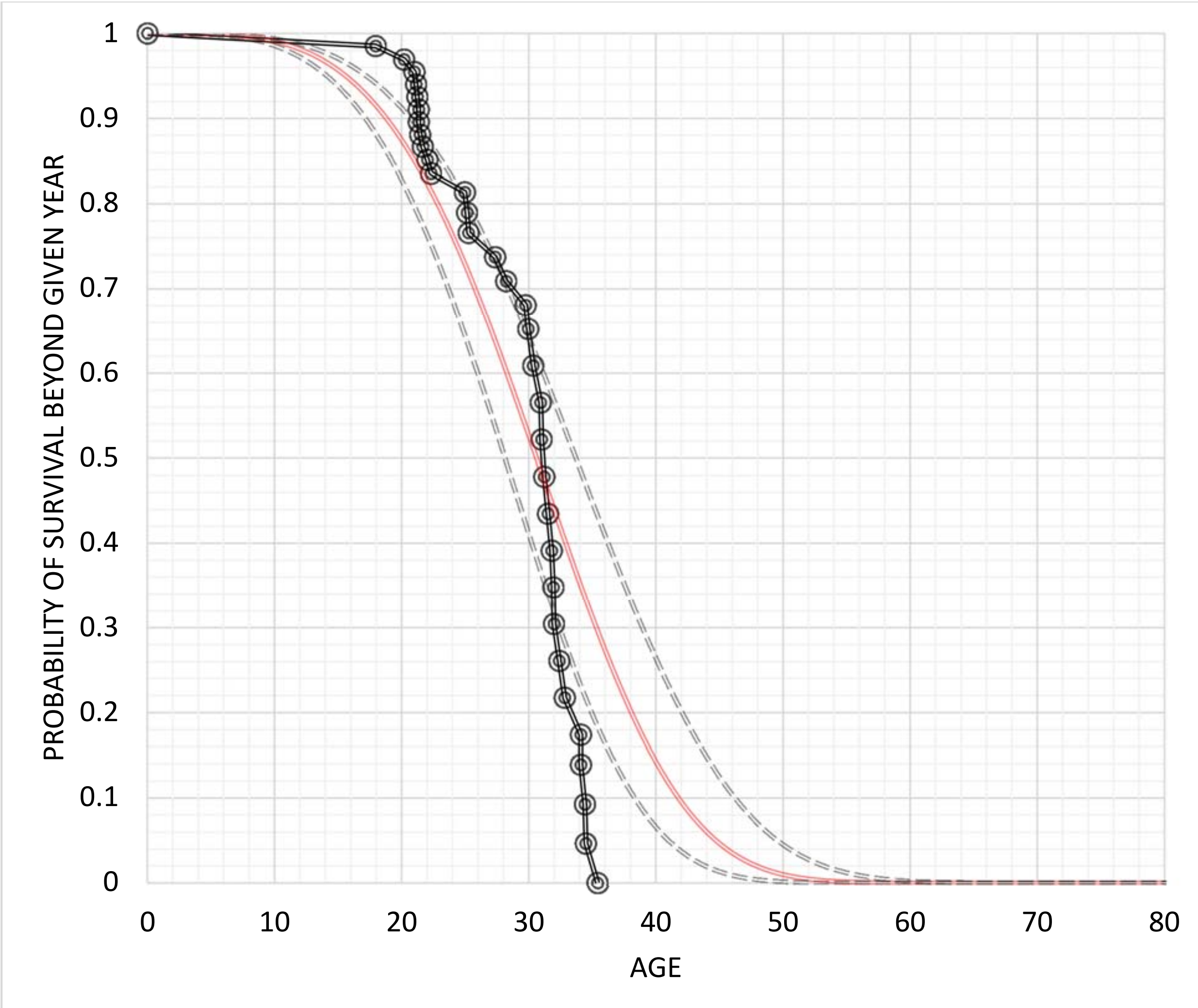

Figure 3-54
Survival Function 115 kV Gas

Forecasting Removals

Figures 3-55 and 3-56 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-55. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 6 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 6 or fewer. Figure 3-56 presents the cumulative results combining each year of the five year period.

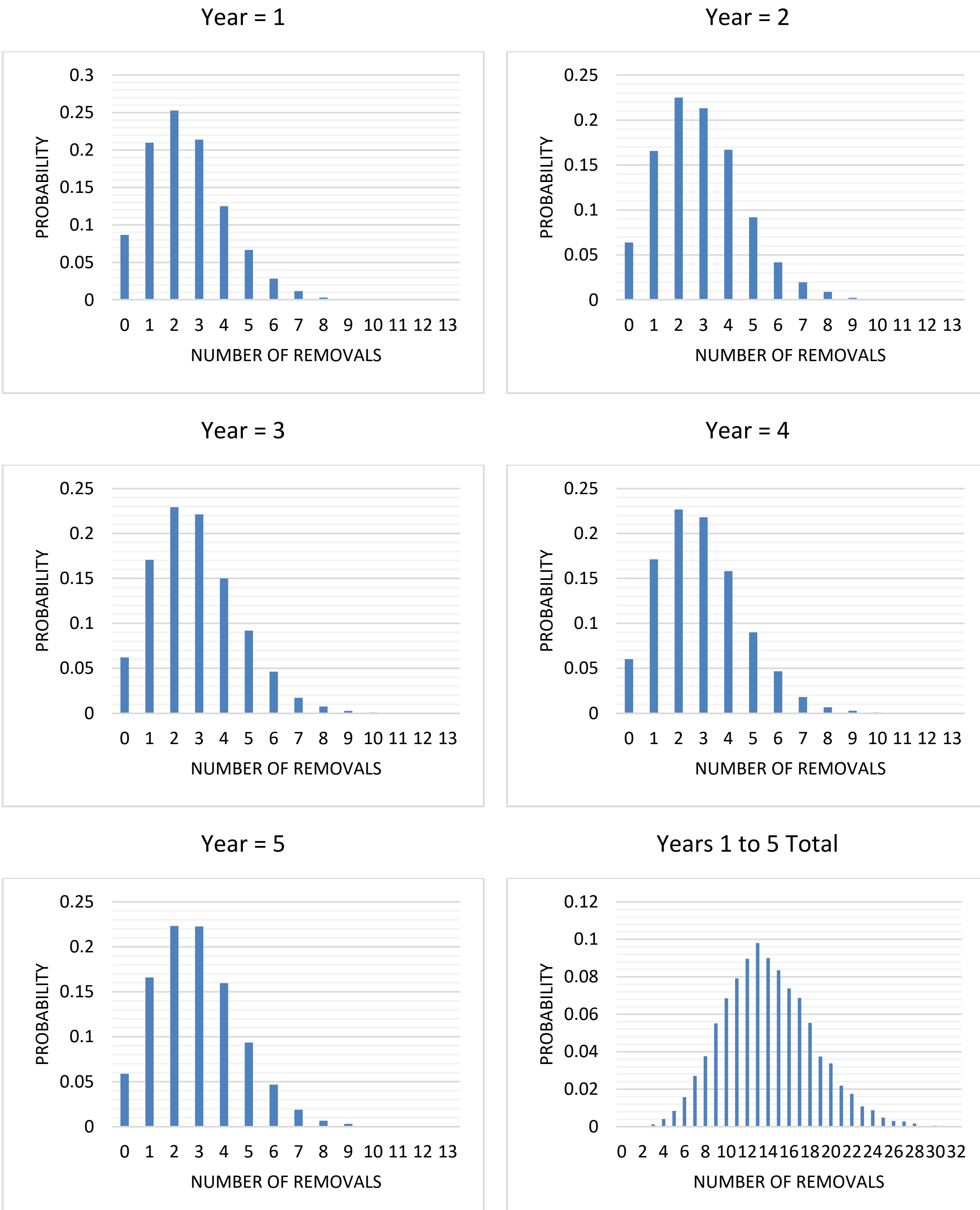

Figure 3-55
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 115 kV Gas

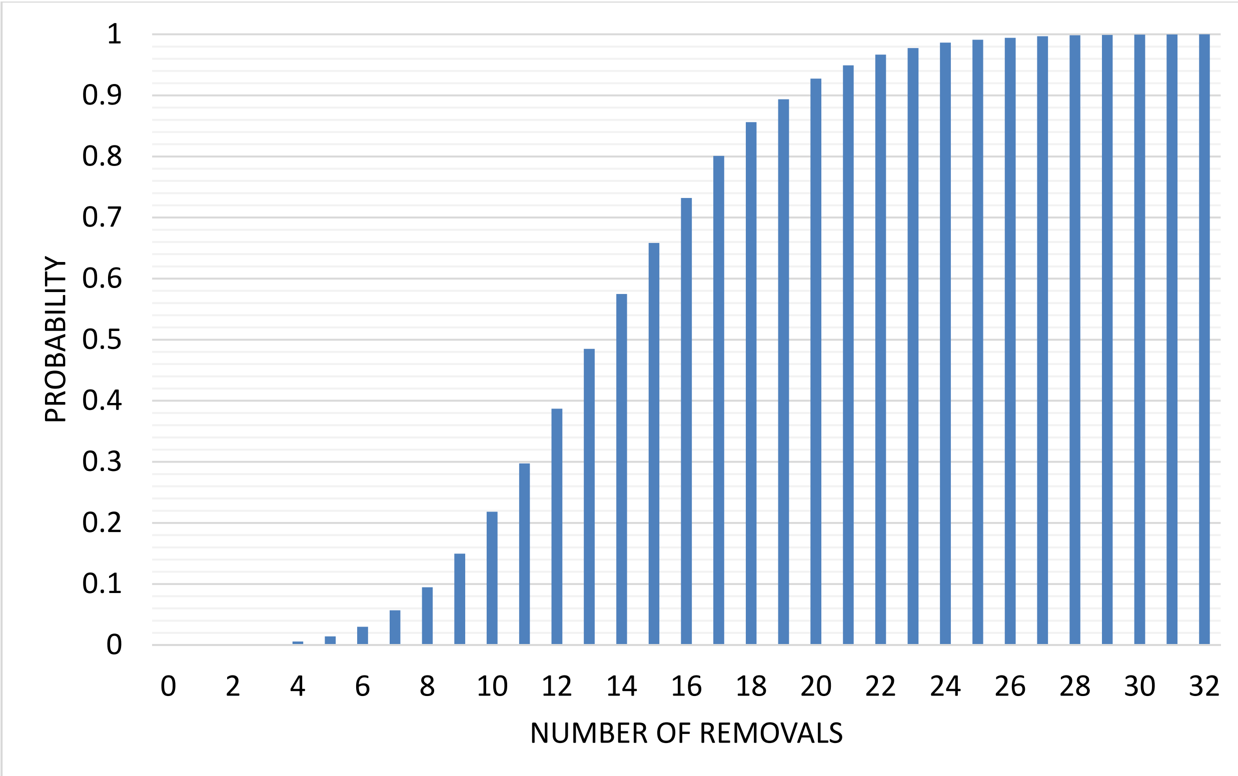

Figure 3-56
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 115 kV Gas

115 kV Oil Removal Analysis

The following provides the results of the 115 kV Oil circuit breaker group analyzed using the method describe in Chapter 2. Table 3-8 shows the number of circuit breakers in-service and removed from service.

Table 3-8
Circuit breaker Group Data 115 kV Oil

Group	In-service	Removed from Service
115 kV Oil	227	255

Age Demographics 115 kV Oil

Figures 3-57 and 3-58 show the age demographics for both in service and removed from service circuit breaker units.

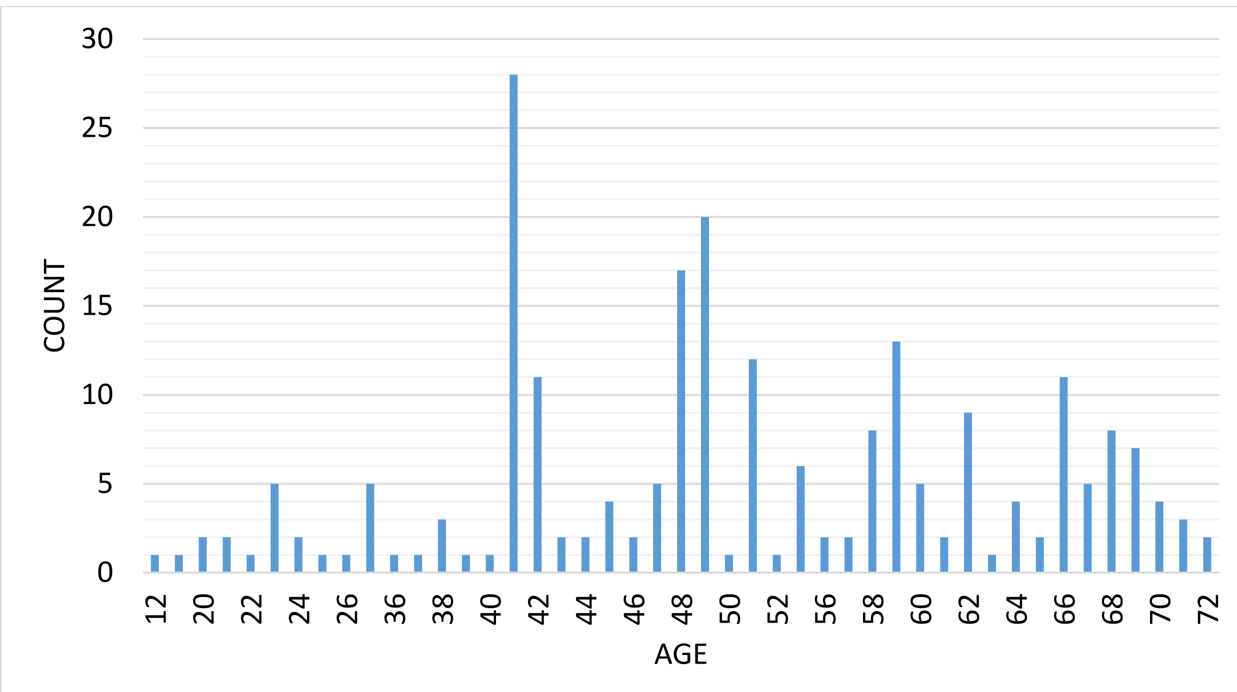

Figure 3-57
Age Demographics In-service 115 kV Oil

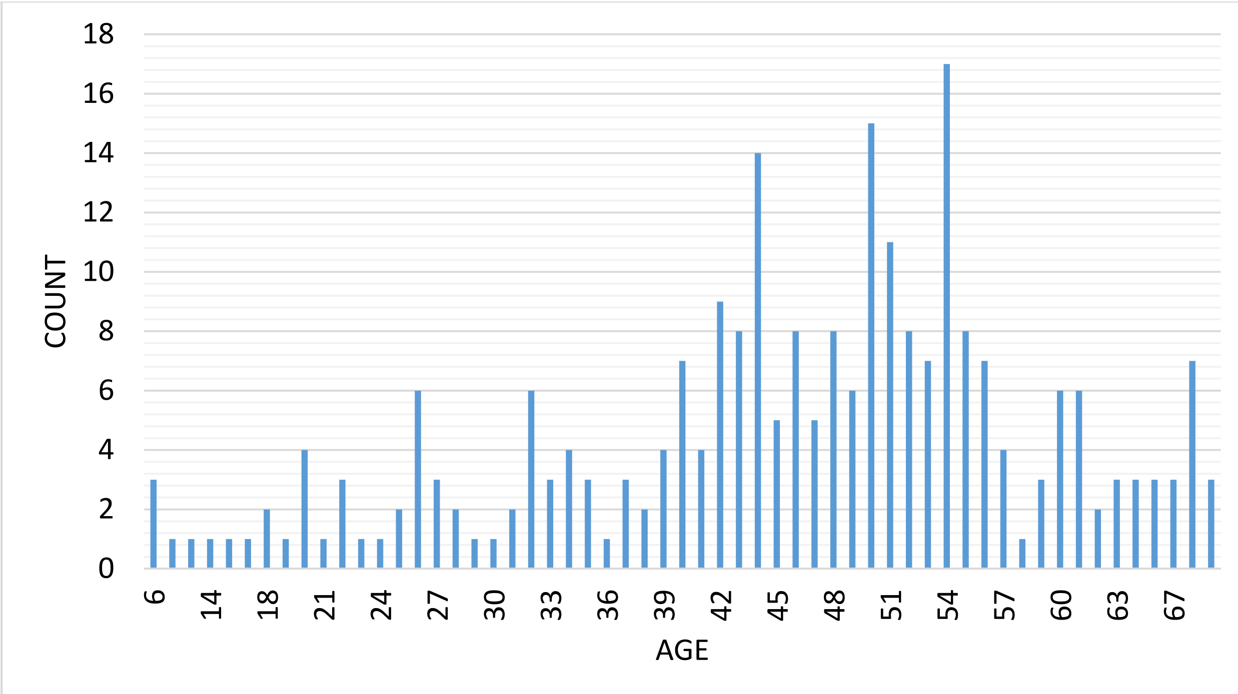

Figure 3-58
Age Demographics Removed From Service 115 kV Oil

Figures 3-59 and 3-60 show the Service Eras and Service Ages of the 115 kV Oil circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1985. The relatively large number of breakers removed before age 20 suggests that these removals may have been for some unusual and potentially one-off reason. Therefore, the model results may be unnecessarily pessimistic.

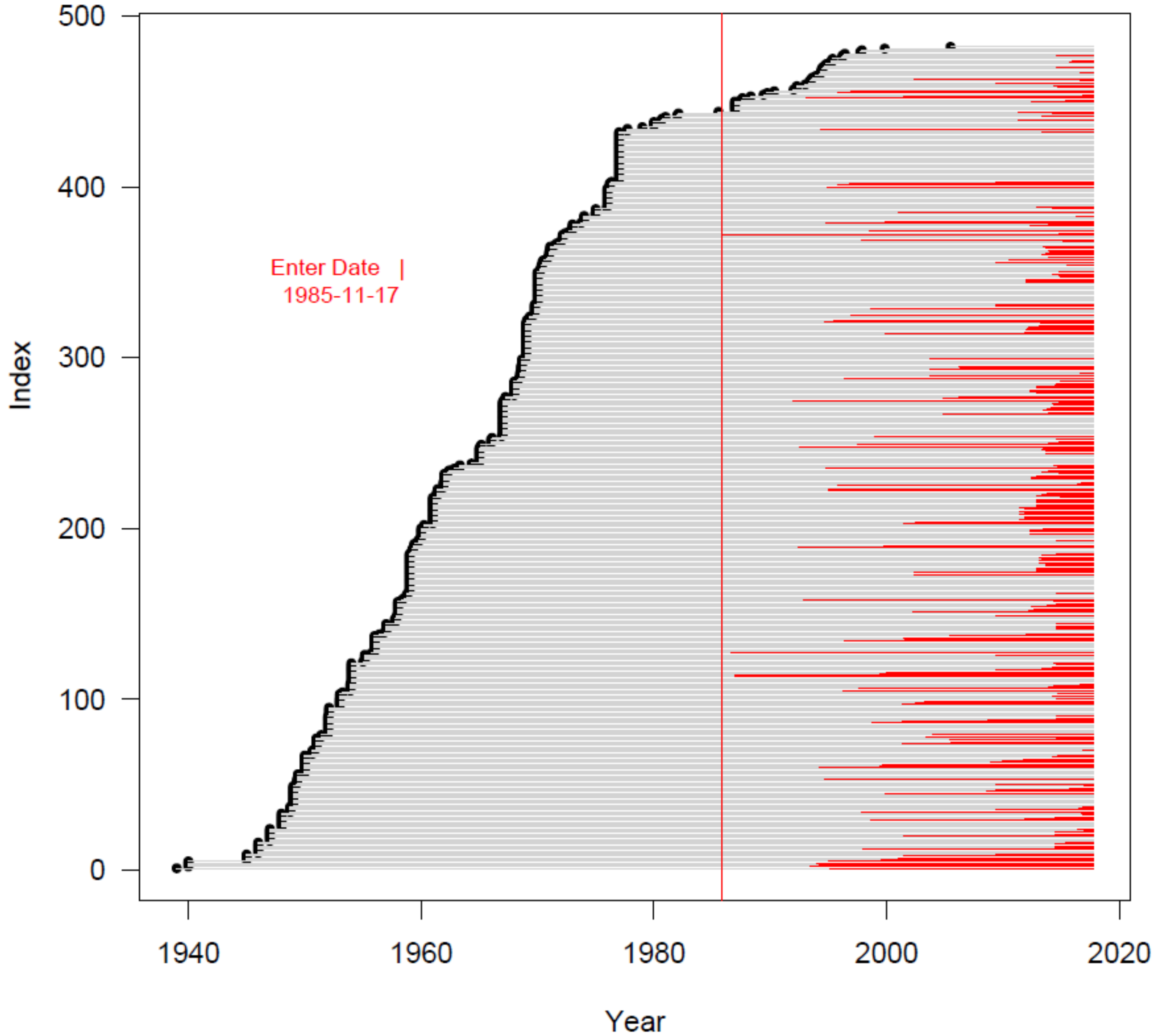

Figure 3-59
Service Eras 115 kV Oil

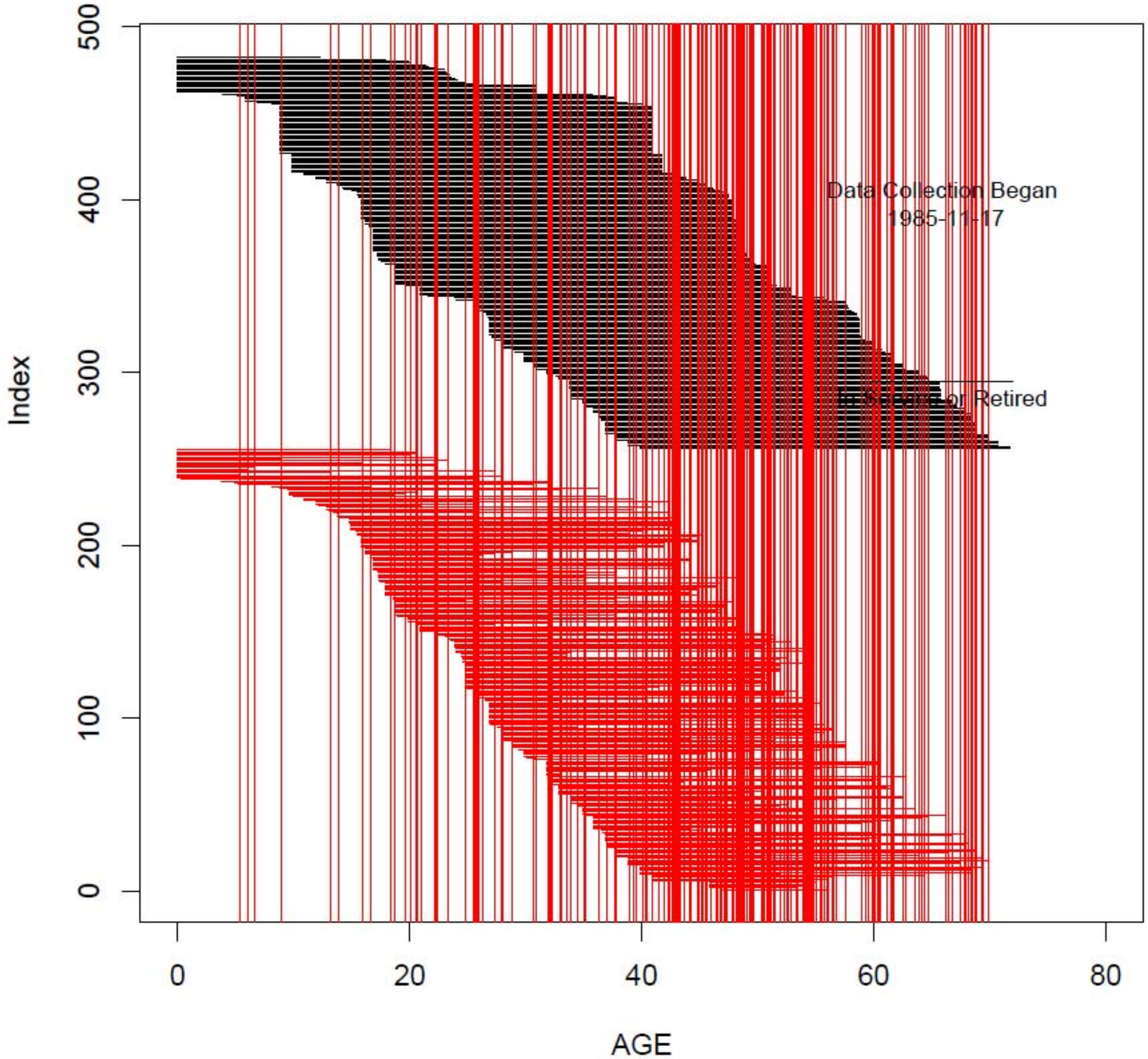

Figure 3-60
Service Ages 115 kV Oil

Removal Hazard Rate 115 kV Oil

Figure 3-61 shows the removal rate developed using the in-service and removed from service data provided for the 115 kV Oil circuit breaker. In the figure, probability of a 40 year old circuit breaker being removed in its next year of life ranges from 2.3% to 2%. For a 60 year old circuit breaker the probability of being removed in its next year of life ranges from 3.9% to 5.6%. Note the 95% confidence intervals. The bands become larger above age 70, reflecting the sparse number of recorded removals in these regions.

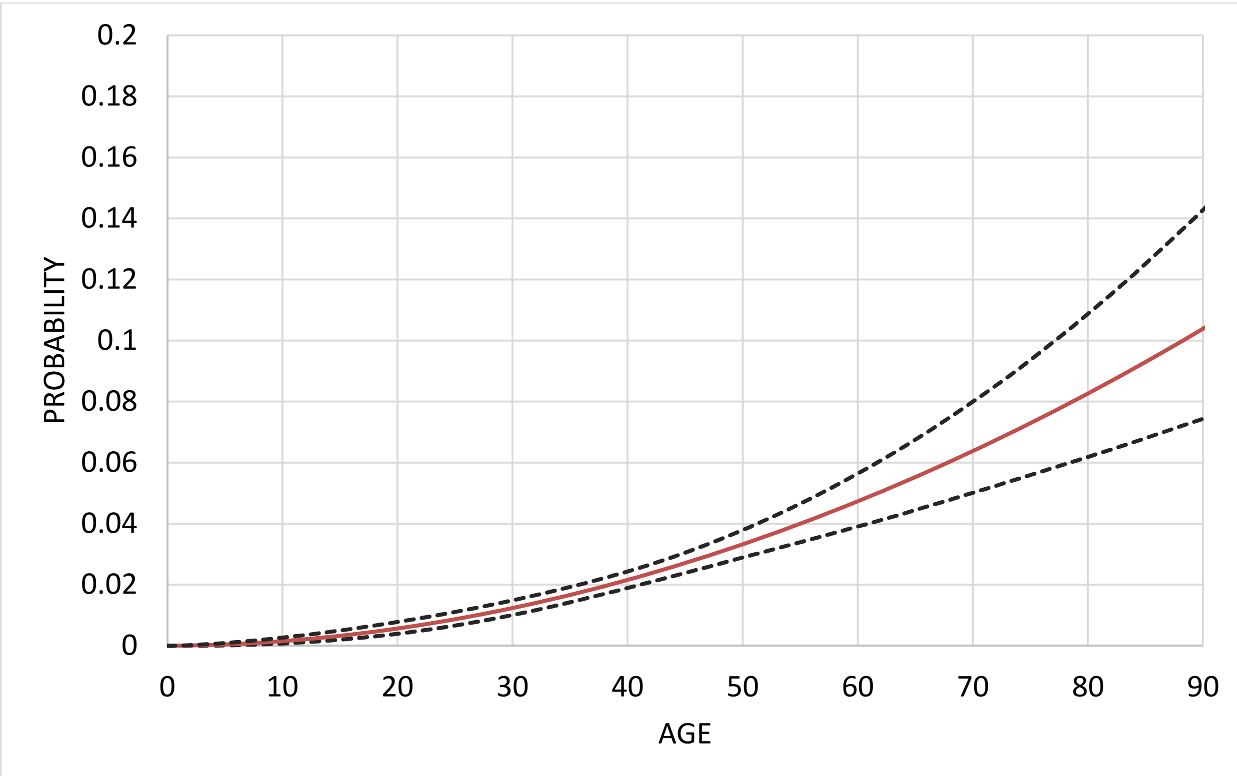

Figure 3-61
Removal Rate 115 kV Oil

Survival Function 115 kV Oil

Figure 3-62 shows the survival function developed using the in-service and removed from service data provided for the 115 kV Oil Air circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 71% to 78%.

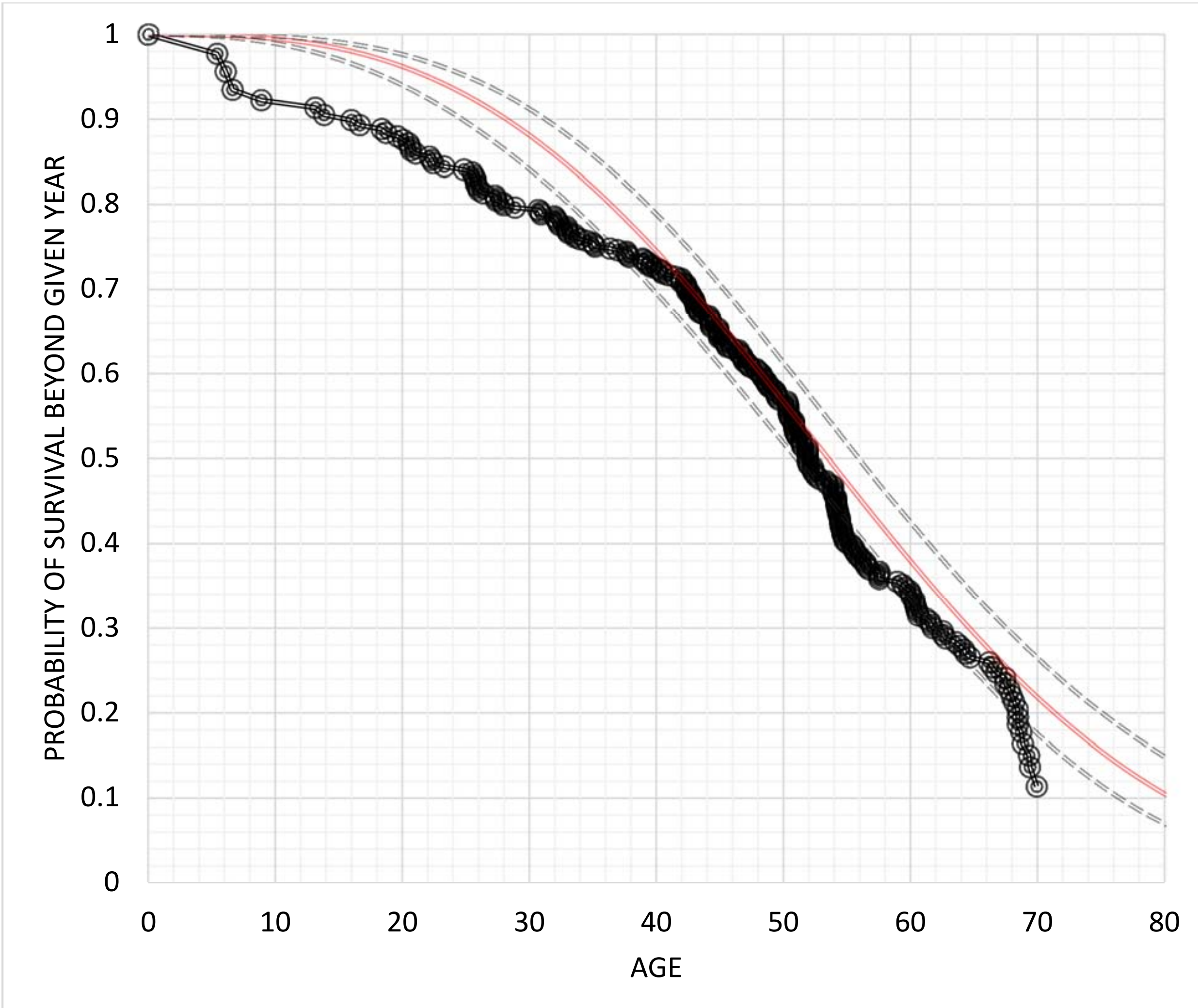

Figure 3-62
Survival Function 115 kV Oil

Forecasting Removals

Figures 3-63 and 3-64 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-63. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 14 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 14 or fewer. Figure 3-64 presents the cumulative results combining each year of the five year period.

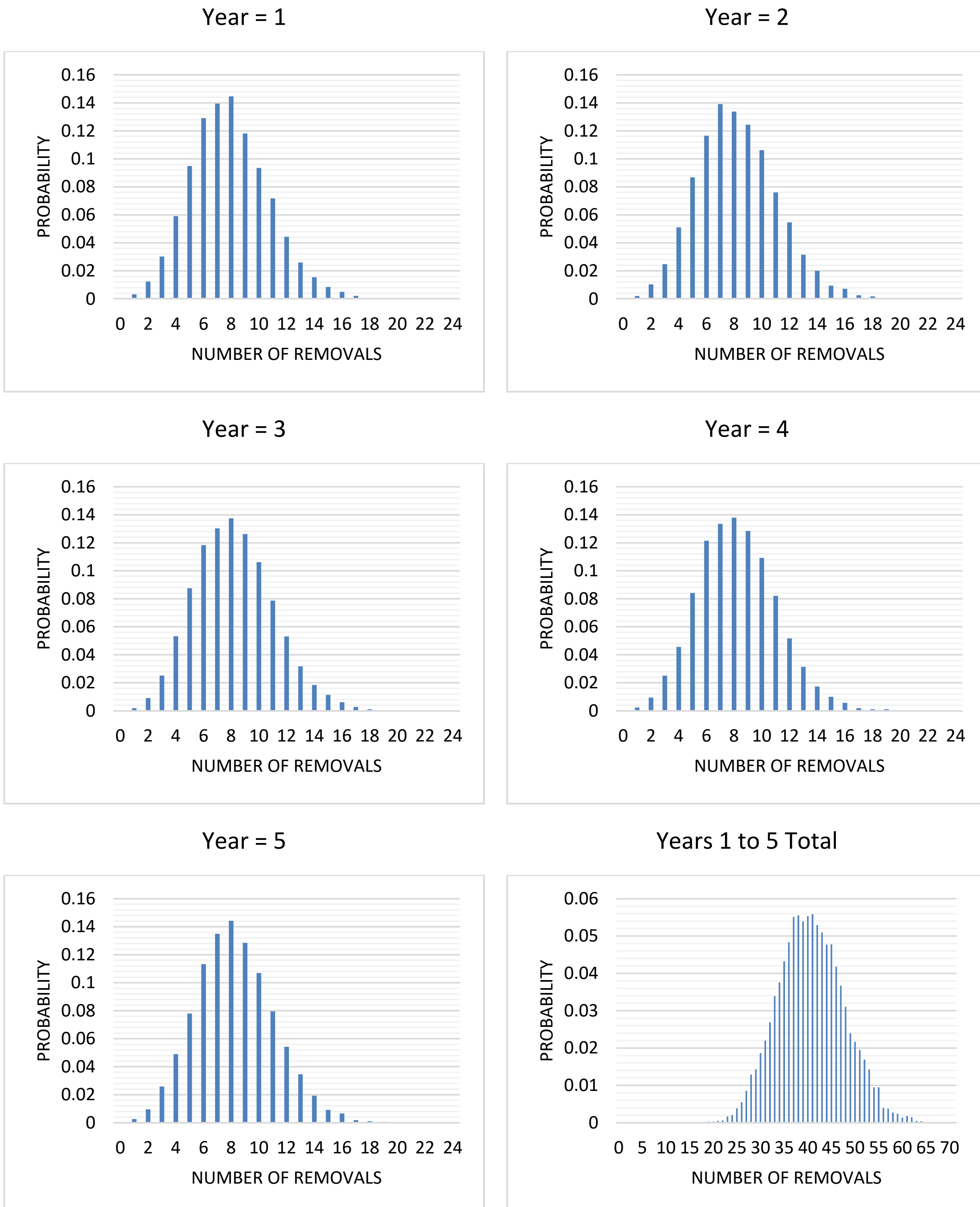

Figure 3-63
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 115 kV Oil

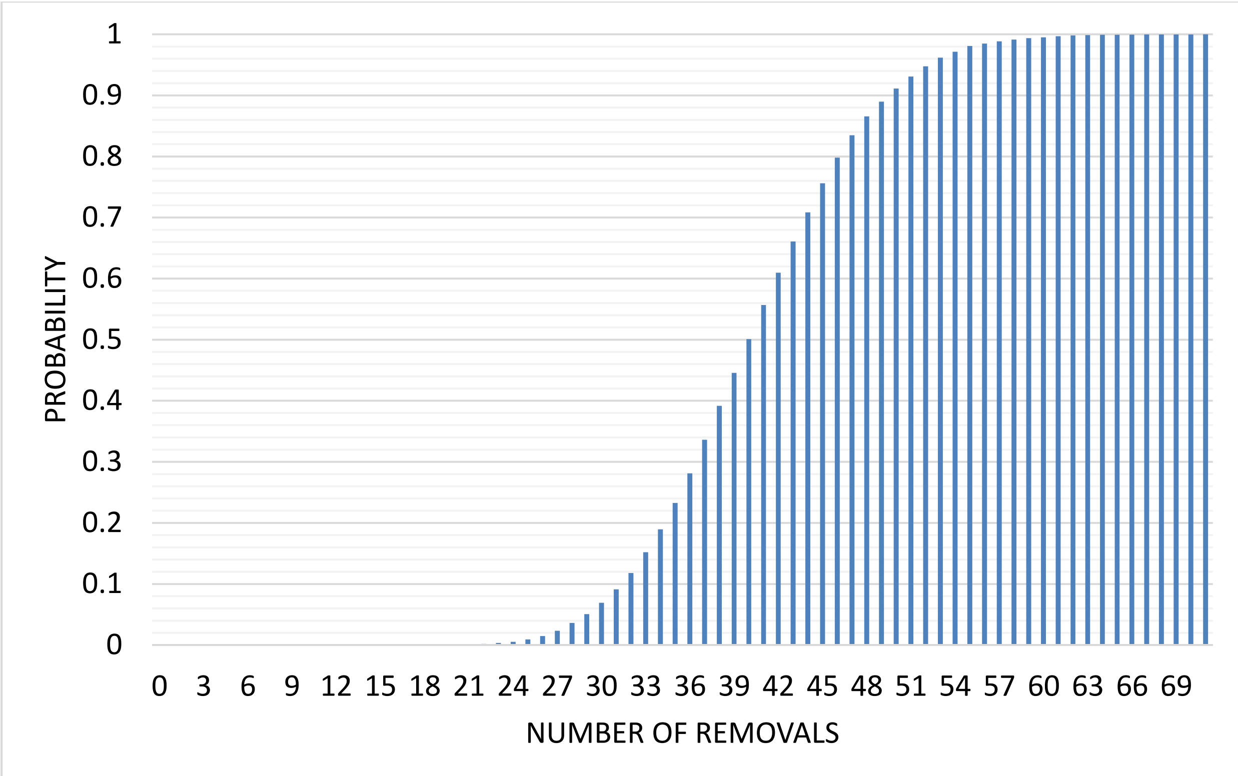

Figure 3-64
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 115 kV Oil

230 kV Gas Removal Analysis

The following provides the results of the 230 kV Gas circuit breaker group analyzed using the method describe in Chapter 2. Table 3-9 shows the number of circuit breakers in-service and removed from service.

Table 3-9
Circuit breaker Group Data 230 kV Gas

Group	In-service	Removed from Service
230 kV Gas	417	28

Age Demographics 230 kV Gas

Figures 3-65 and 3-66 show the age demographics for both in service and removed from service circuit breaker units.

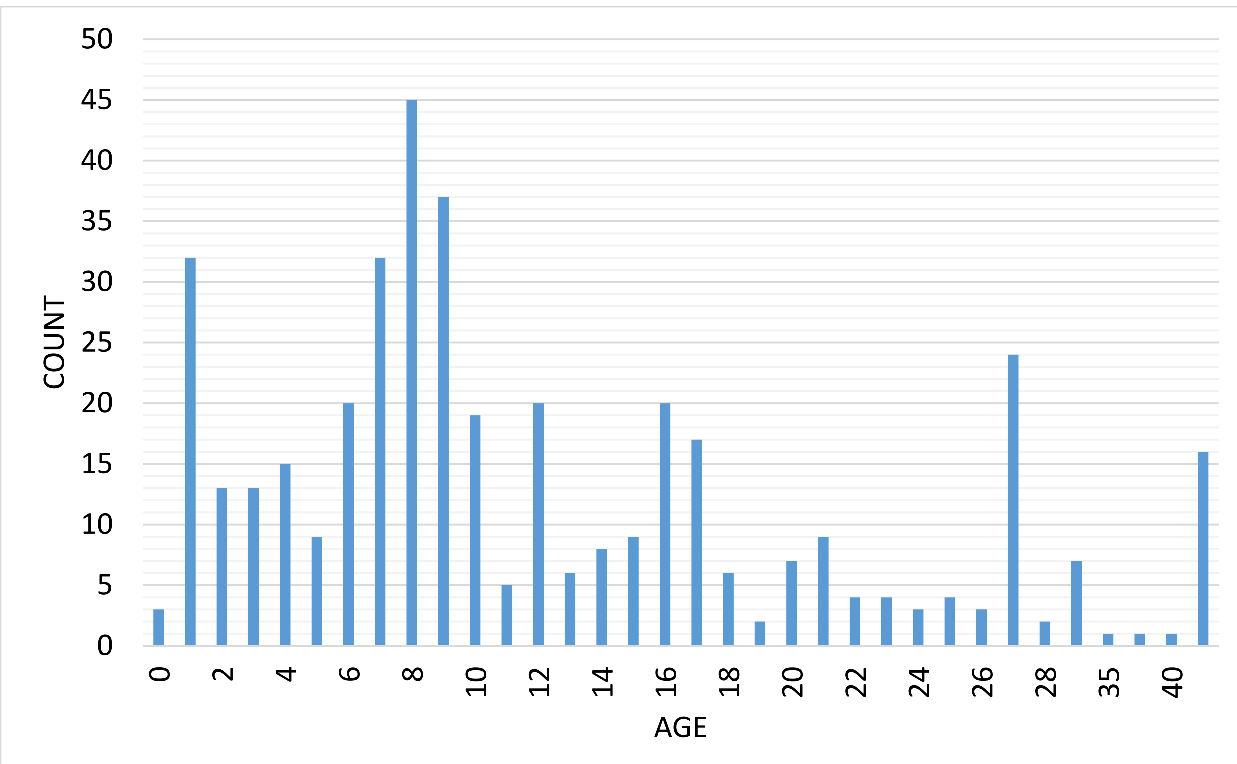

Figure 3-65
Age Demographics In-service 230 kV Gas

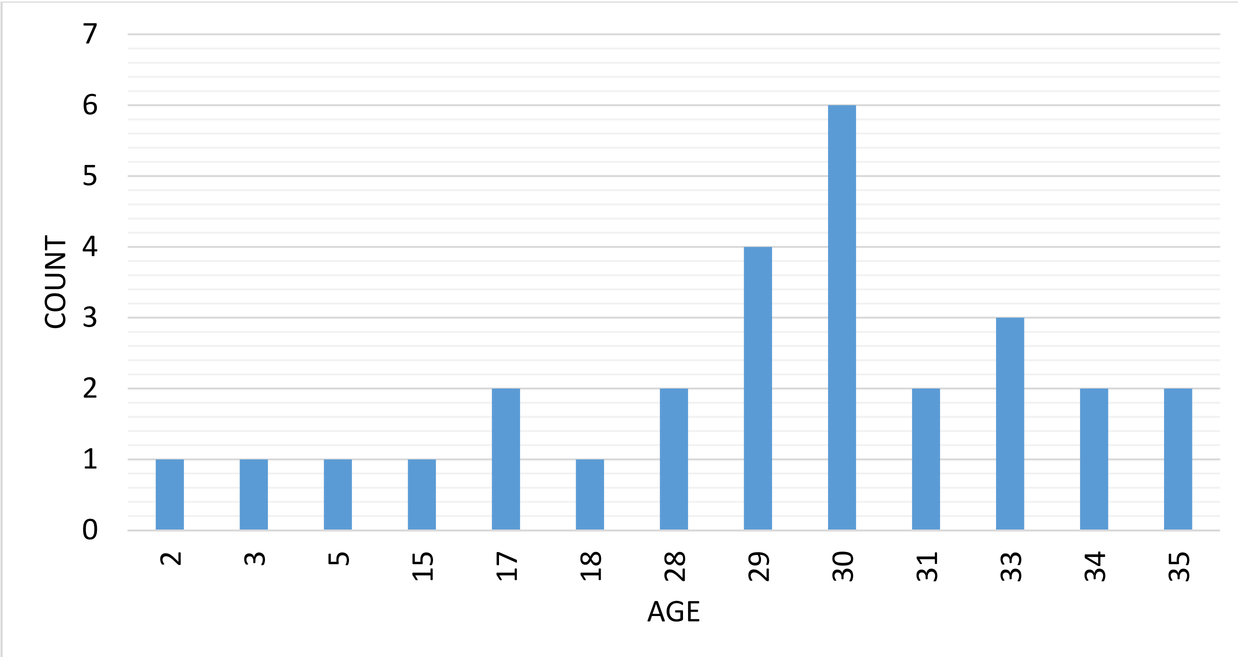

Figure 3-66
Age Demographics Removed From Service 230 kV Gas

Figures 3-67 and 3-68 show the Service Eras and Service Ages of the 230 kV Gas circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1995.

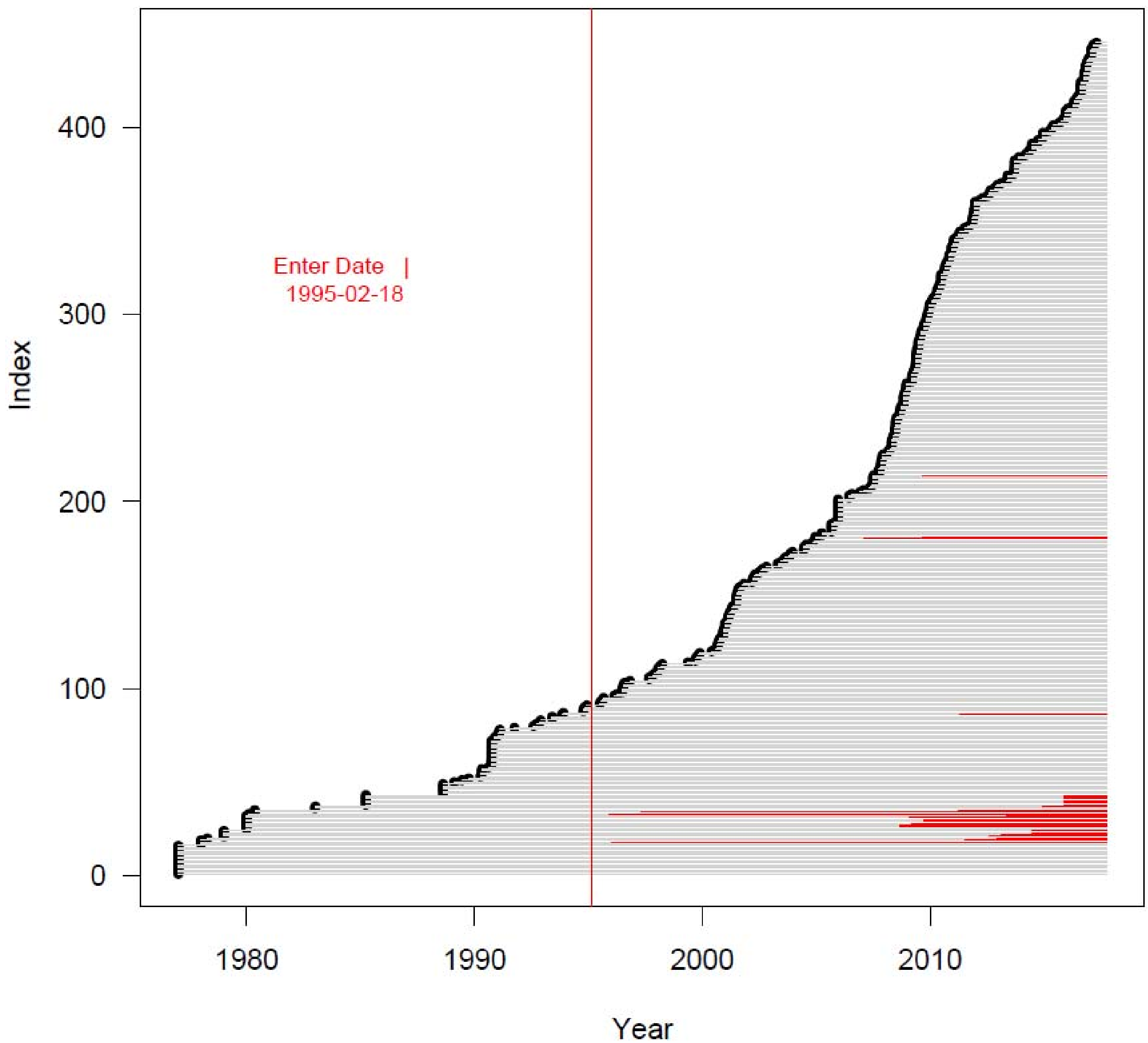

Figure 3-67
Service Eras 230 kV Gas

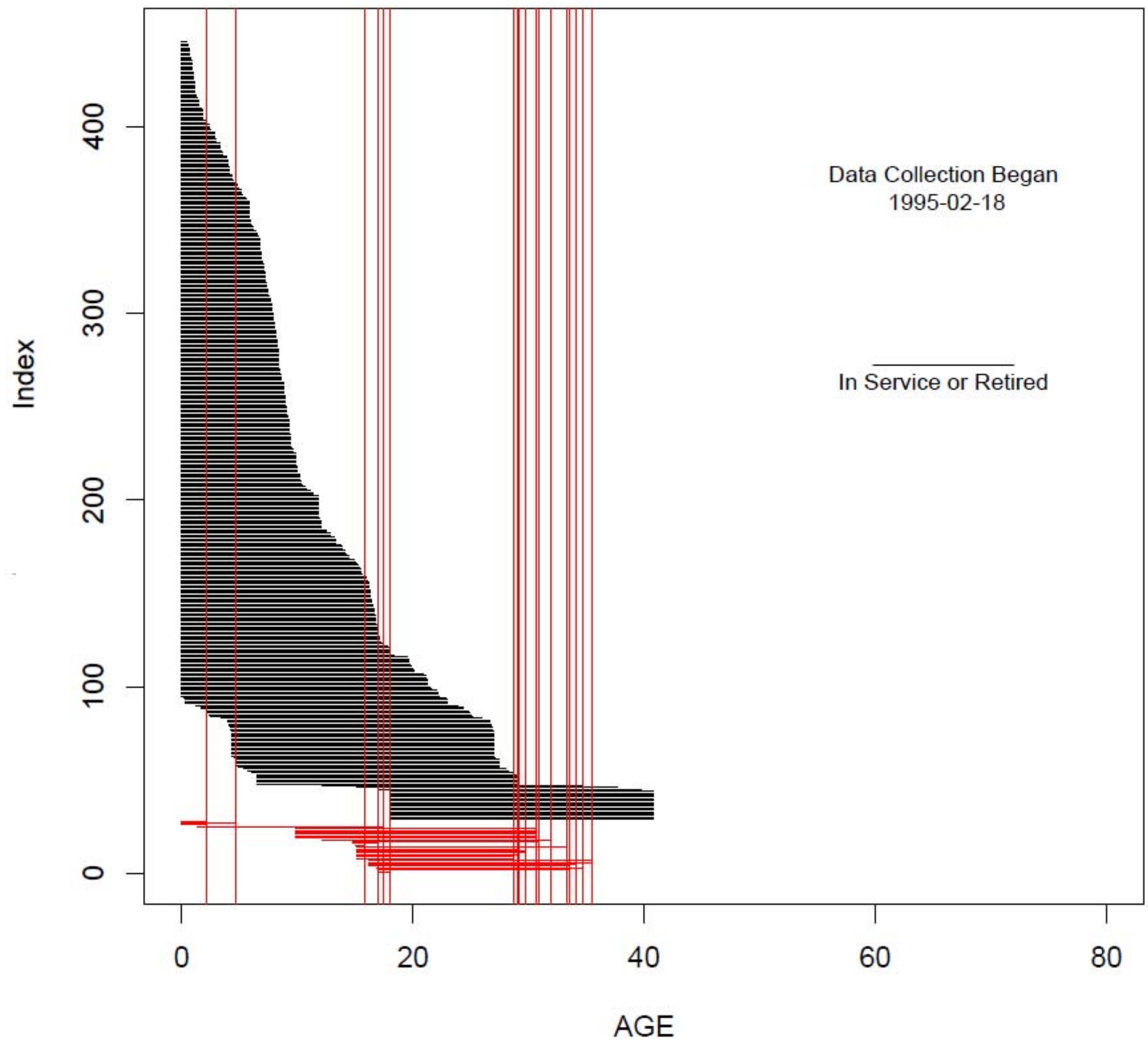

Figure 3-68
Service Ages 230 kV Gas

Removal Hazard Rate 230 kV Gas

Figure 3-69 shows the removal rate developed using the in-service and removed from service data provided for the 230 kV Gas circuit breaker. In the figure, probability of a 40 year old circuit breaker being removed in its next year of life ranges from 2.1% to 7.1%. For a 60 year old circuit breaker the probability of being removed in its next year of life ranges from 3.6% to 21%. Note the 95% confidence intervals. The bands become larger above age 50, reflecting the sparse number of recorded removals in these regions.

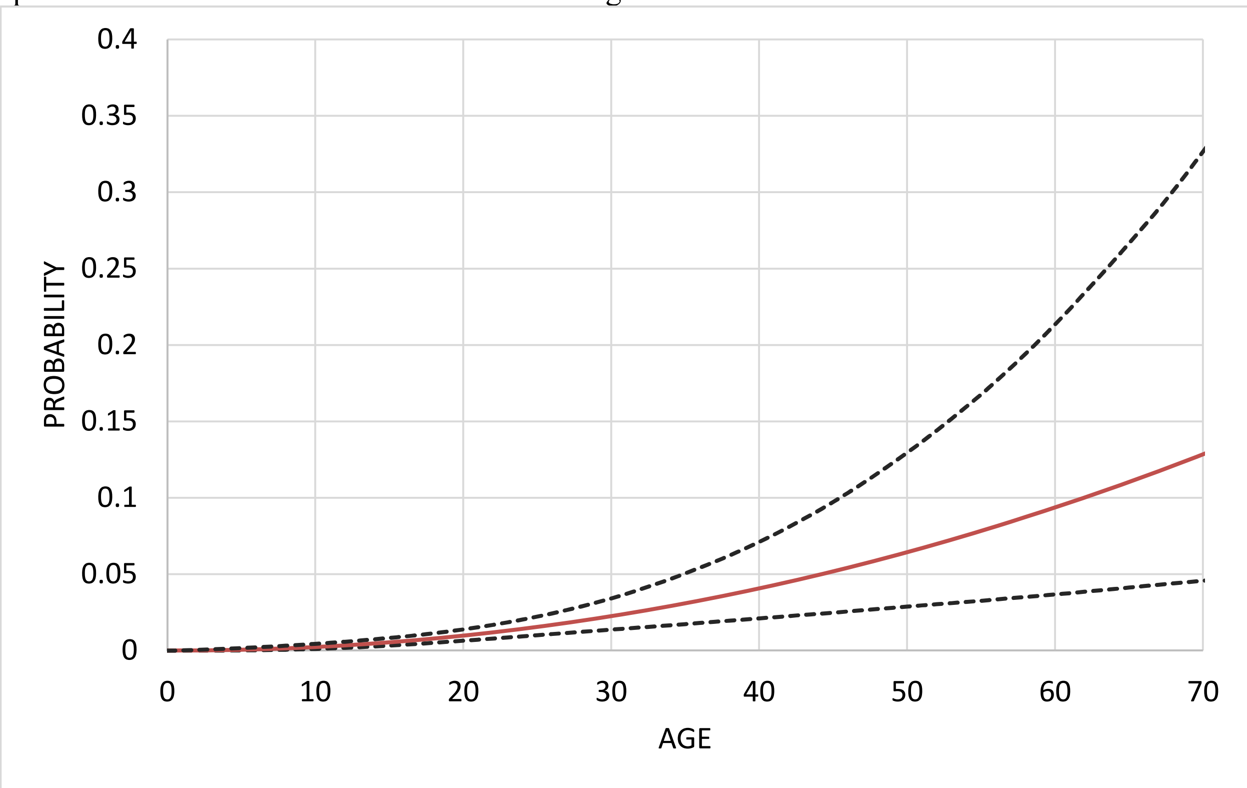

Figure 3-69
Removal Rate 230 kV Gas

Survival Function 230 kV Gas

Figure 3-70 shows the survival function developed using the in-service and removed from service data provided for the 230 kV Gas circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 44% to 71%.

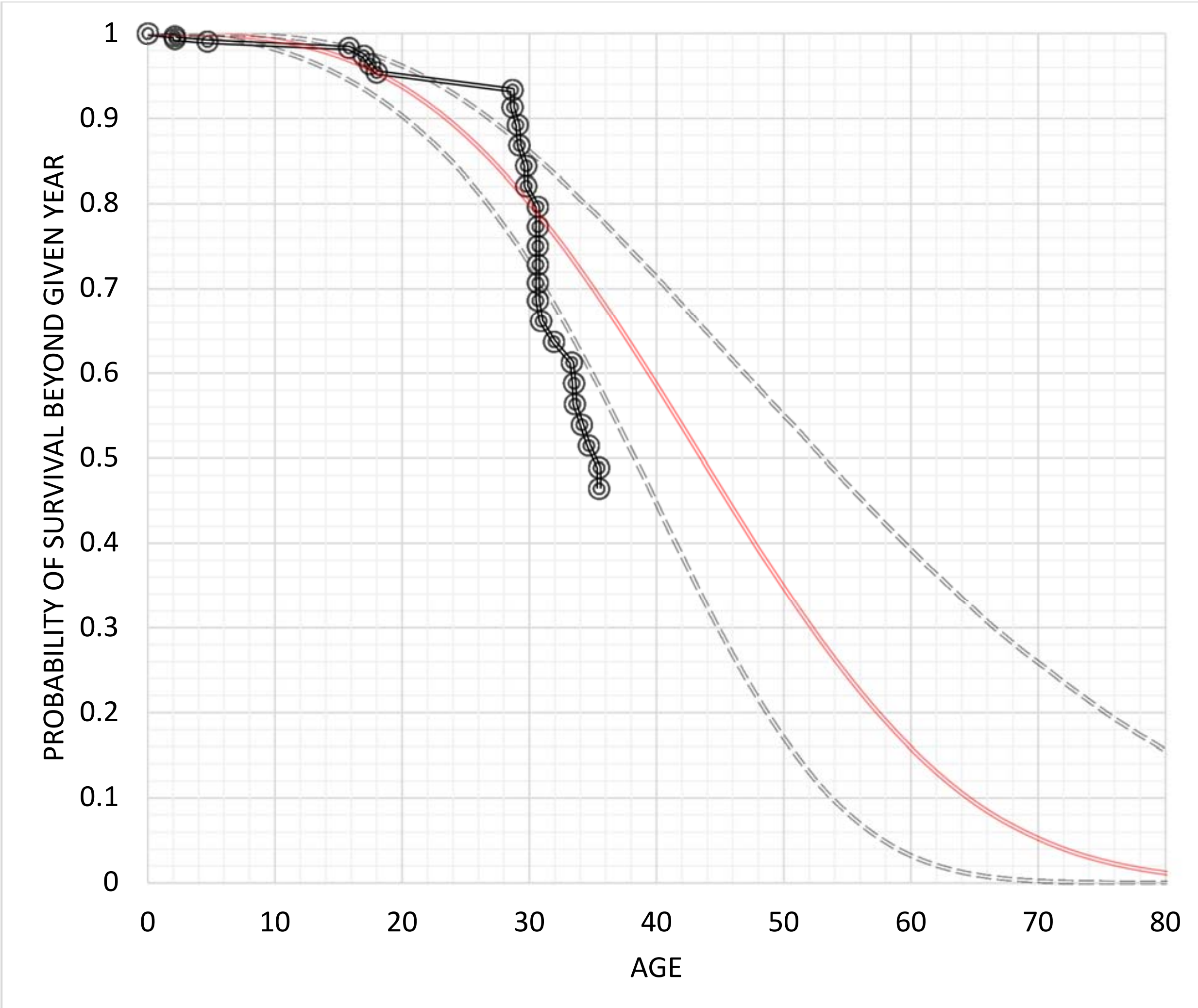

Figure 3-70
Survival Function 230 kV Gas

Forecasting Removals

Figures 3-71 and 3-72 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-71. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 6 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 6 or fewer. Figure 3-72 presents the cumulative results combining each year of the five year period.

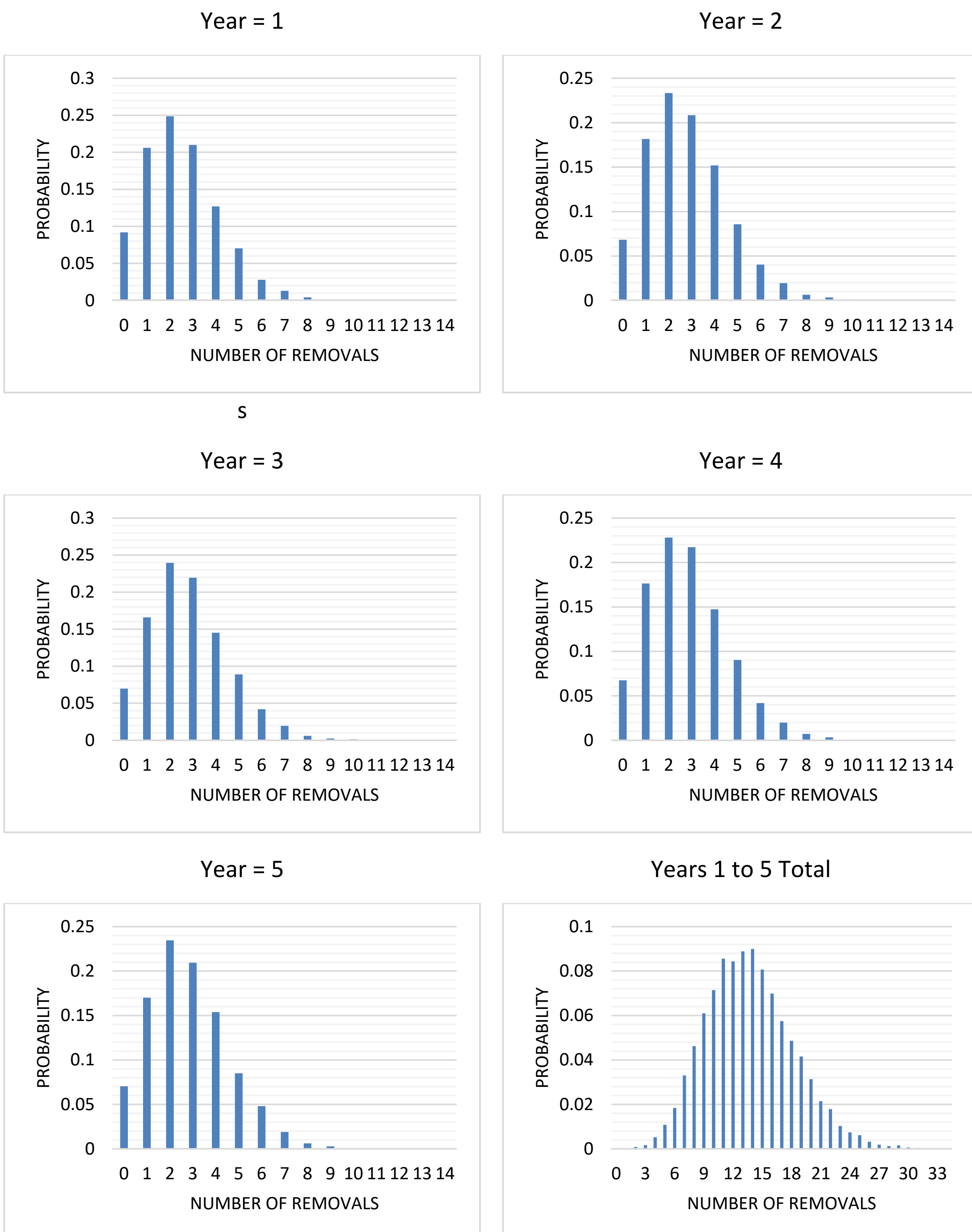

Figure 3-71
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 230 kV Gas

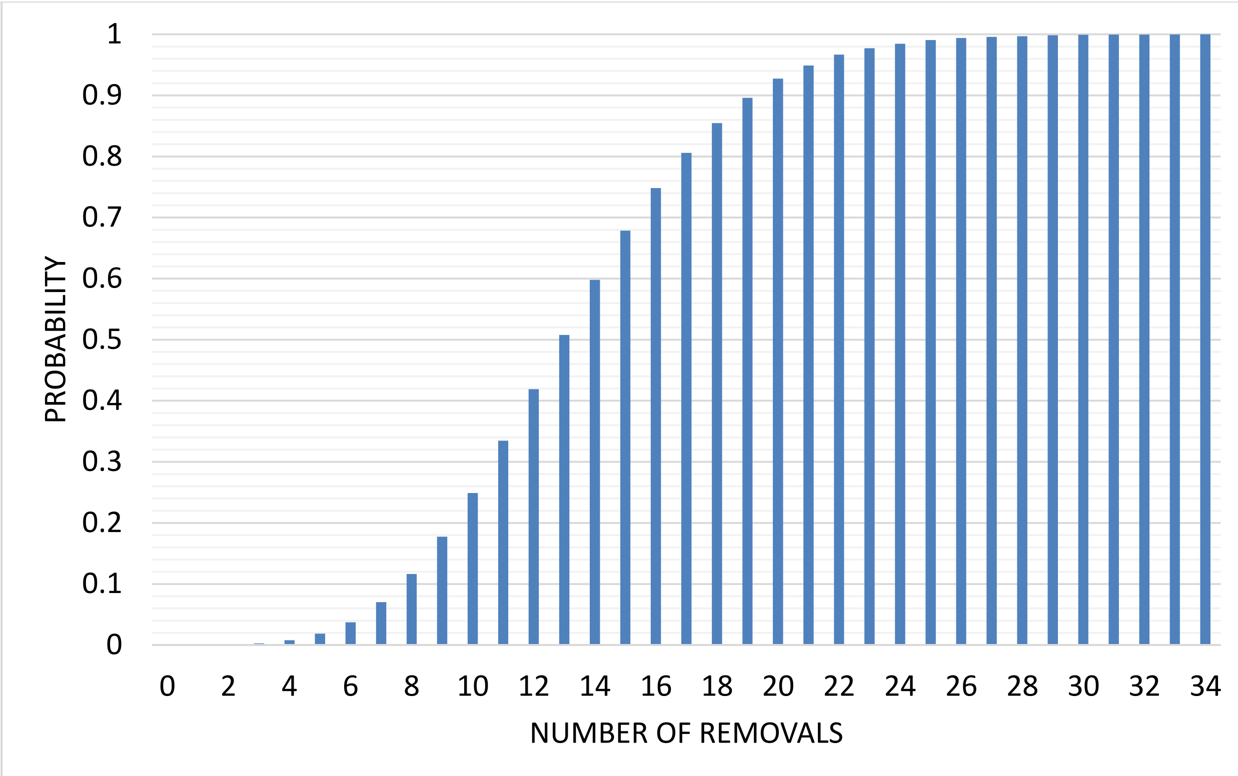

Figure 3-72
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 230 kV Gas

230 kV Oil Removal Analysis

The following provides the results of the 230 kV Oil circuit breaker group analyzed using the method describe in Chapter 2. Table 3-10 shows the number of circuit breakers in-service and removed from service.

Table 3-10
Circuit breaker Group Data 230 kV Oil

Group	In-service	Removed from Service
230 kV Oil	167	123

Age Demographics 230 kV Oil

Figures 3-73 and 3-74 show the age demographics for both in service and removed from service circuit breaker units.

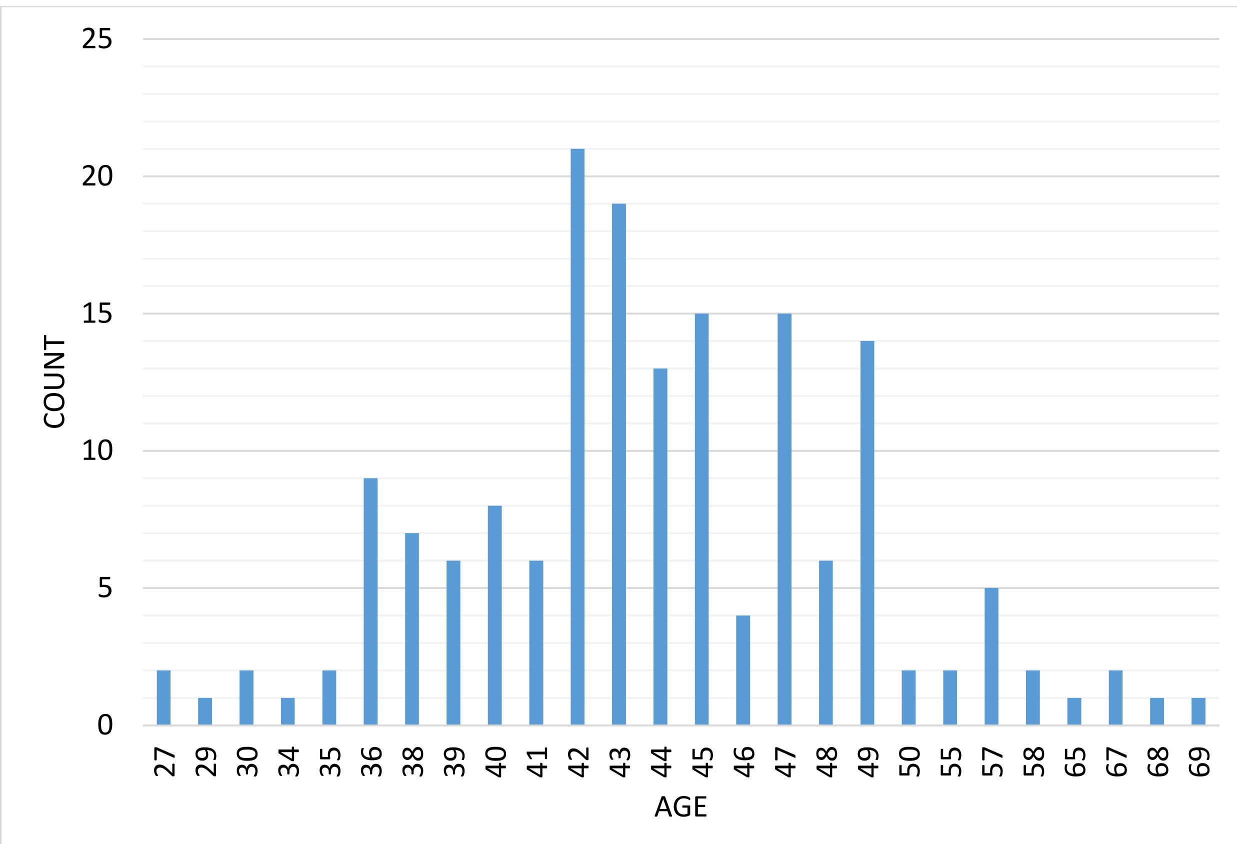

Figure 3-73
Age Demographics In-service 230 kV Oil

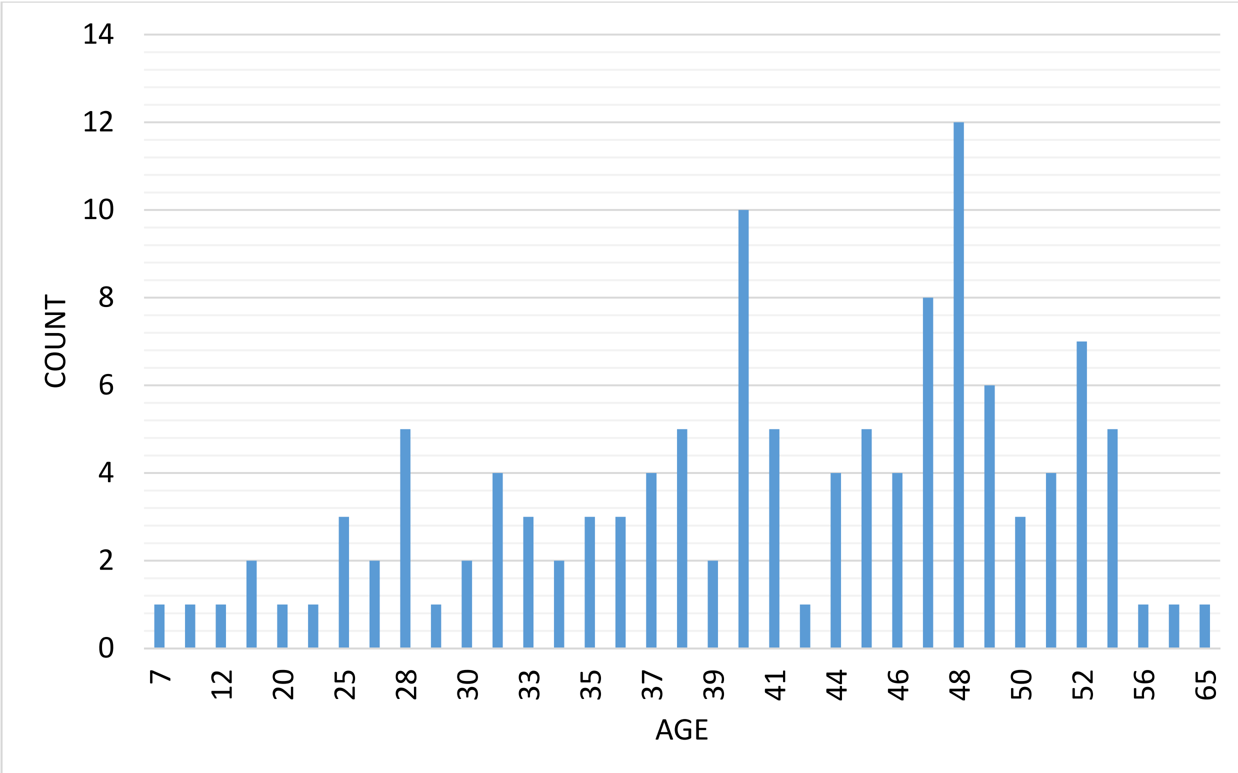

Figure 3-74
Age Demographics Removed From Service 230 kV Oil

Figures 3-75 and 3-76 show the Service Eras and Service Ages of the 230 kV Oil circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1988.

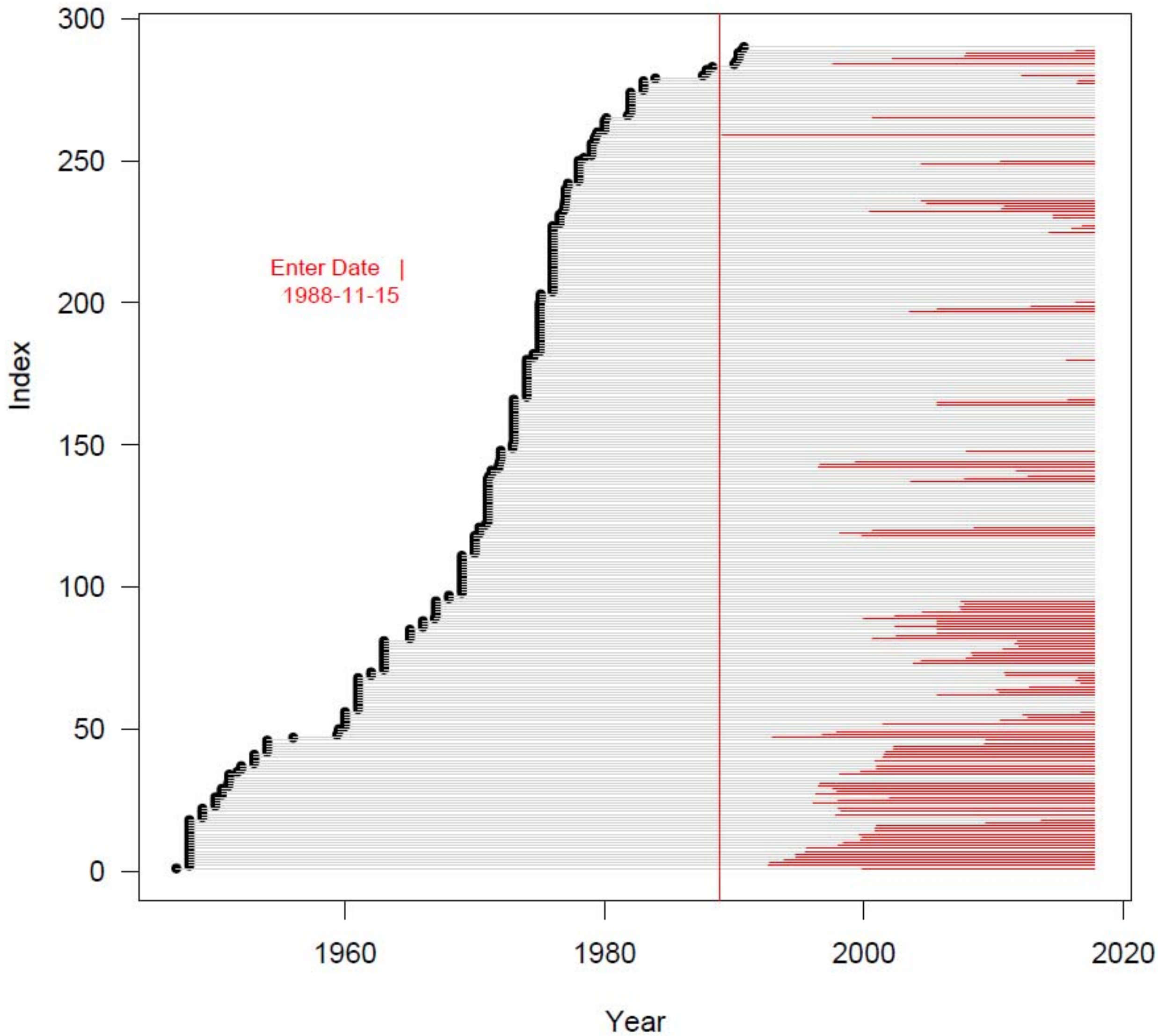

Figure 3-75
Service Eras 230 kV Oil

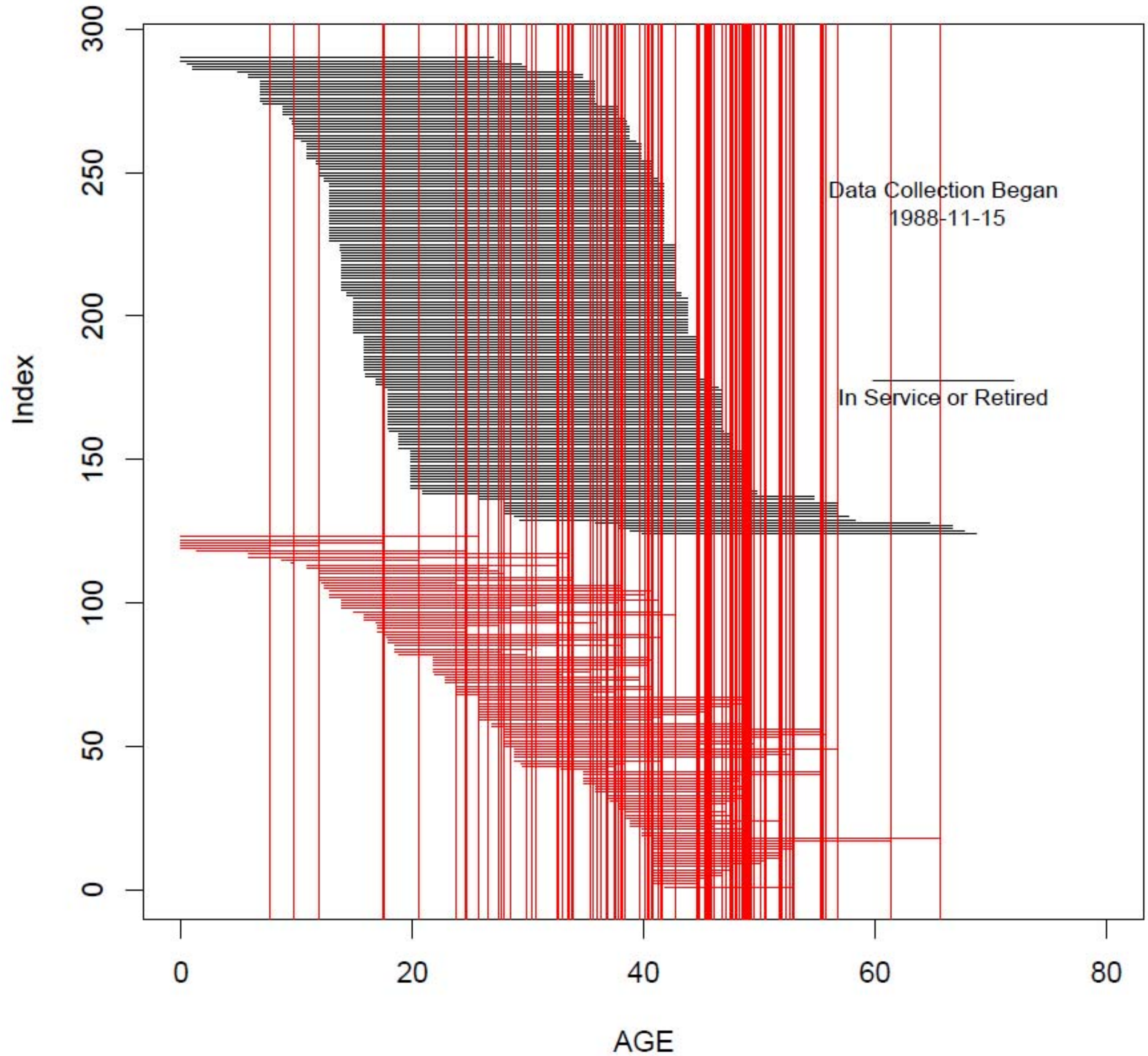

Figure 3-76
Service Ages 230 kV Oil

Removal Hazard Rate 230 kV Oil

Figure 3-77 shows the removal rate developed using the in-service and removed from service data provided for the 230 kV Oil circuit breaker. In the figure, probability of a 40 year old circuit breaker being removed in its next year of life ranges from 2.3% to 3.4%. For a 60 year old circuit breaker the probability of being removed in its next year of life ranges from 6.8% to 10%. Note the 95% confidence intervals. The bands become larger above age 50, reflecting the sparse number of recorded removals in these regions.

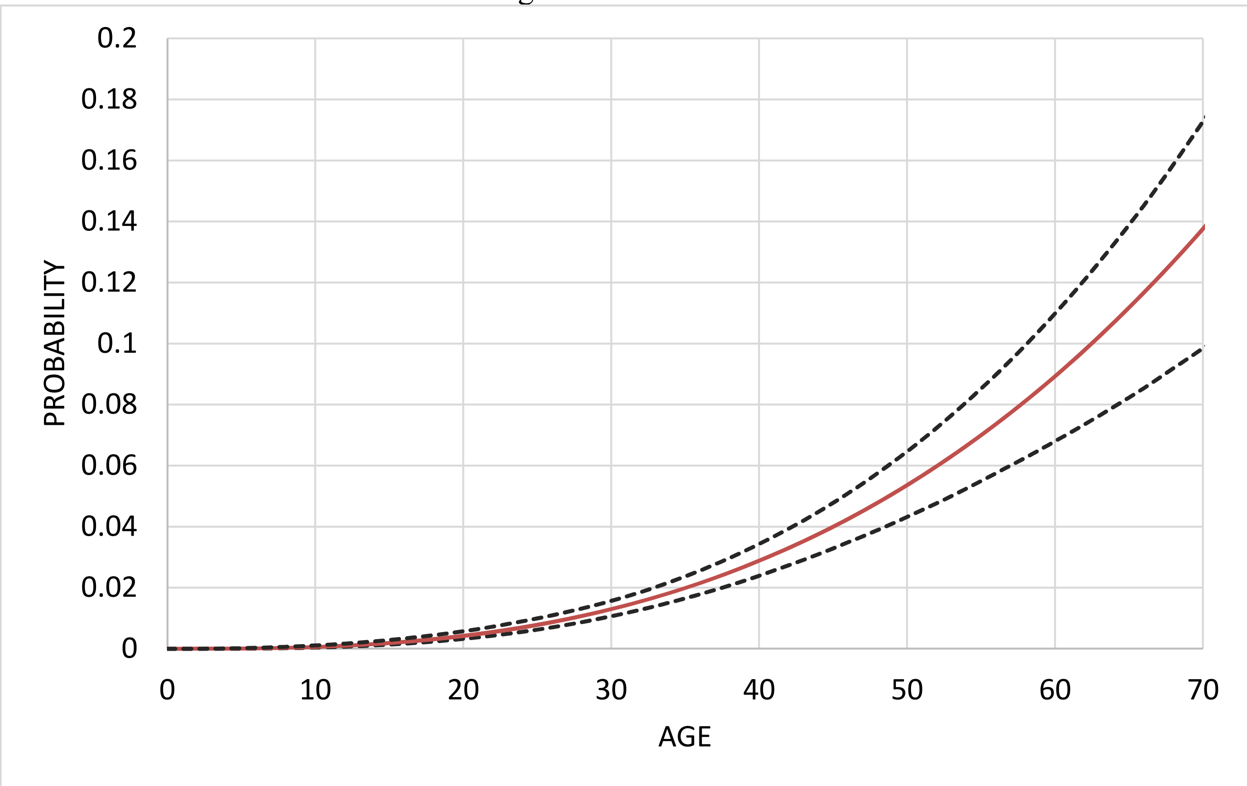

Figure 3-77
Removal Rate 230 kV Oil

Survival Function 230 kV Oil

Figure 3-78 shows the survival function developed using the in-service and removed from service data provided for the 230 kV Oil circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 69% to 77%.

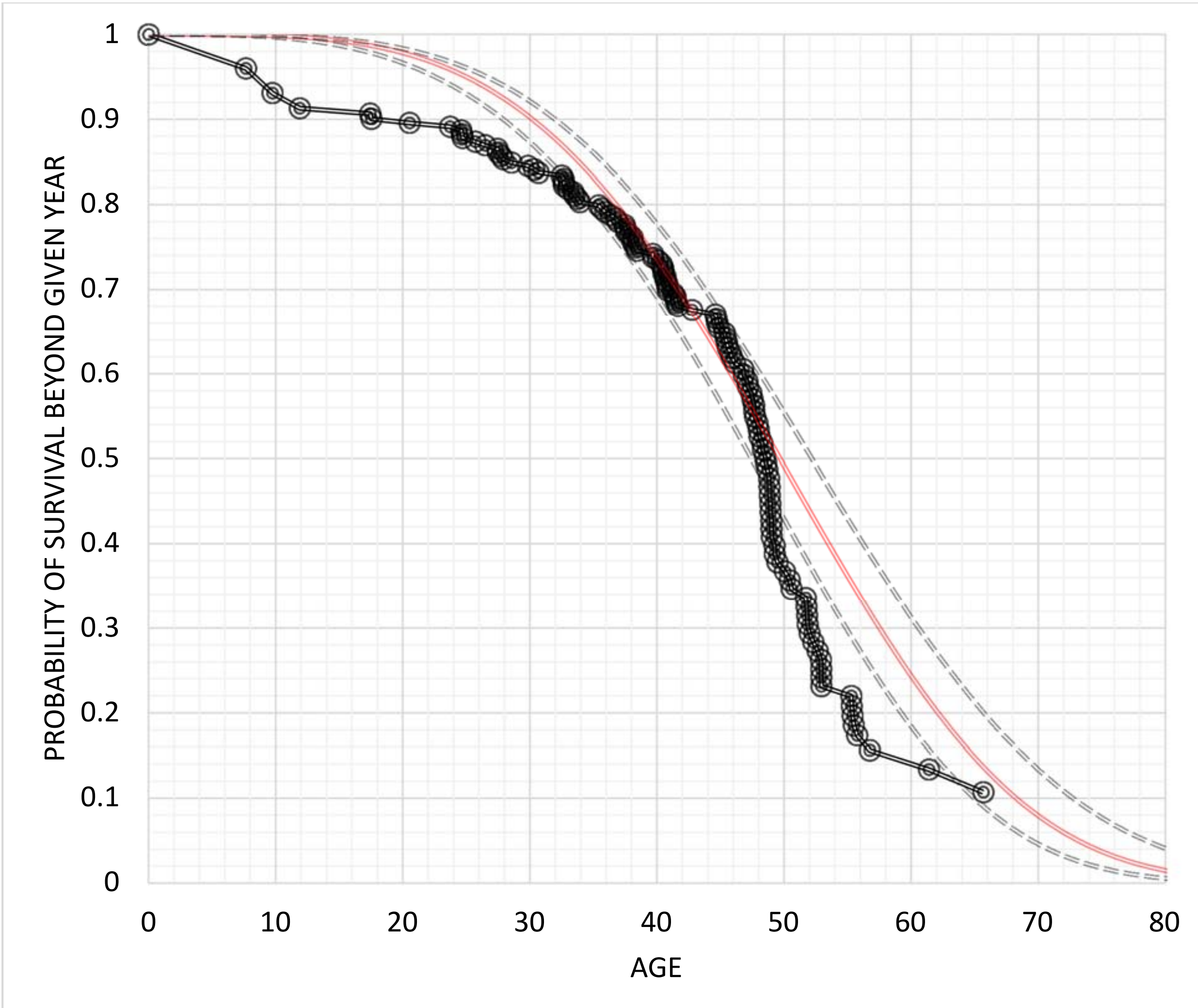

Figure 3-78
Survival Function 230 kV Oil

Forecasting Removals

Figures 3-79 and 3-80 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-79. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 12 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 12 or fewer. Figure 3-80 presents the cumulative results combining each year of the five year period.

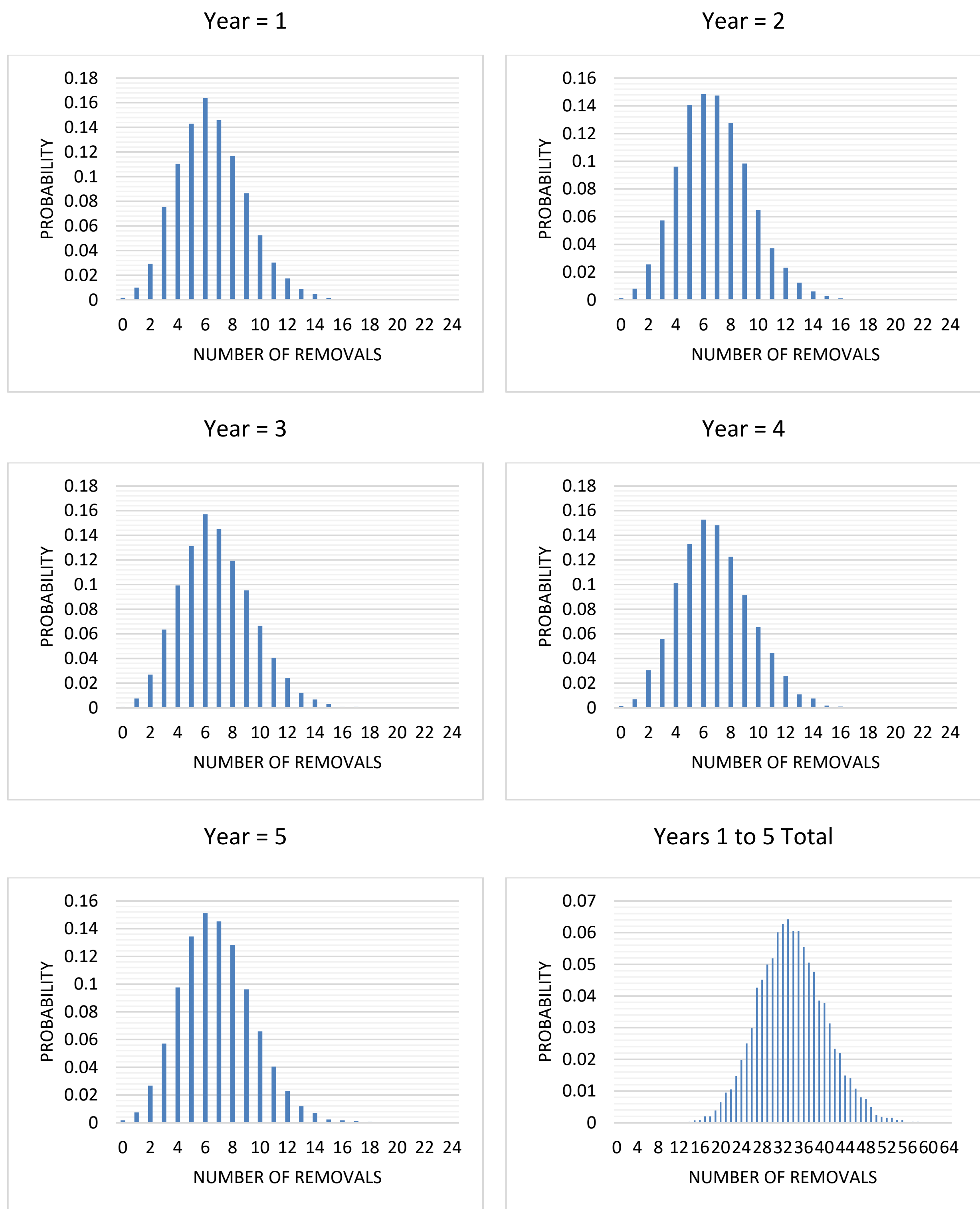

Figure 3-79
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 230 kV Oil

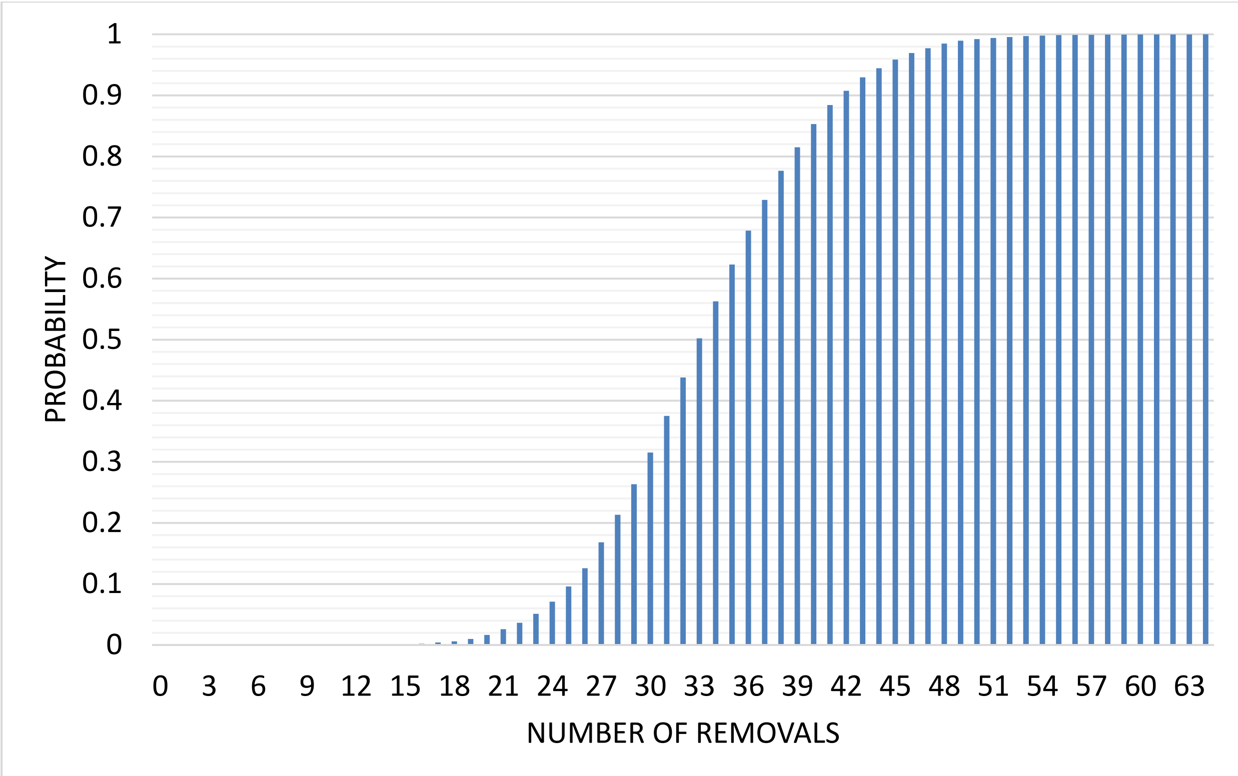

Figure 3-80
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 230 kV Oil

500 kV Gas Removal Analysis

The following provides the results of the 500 kV Gas circuit breaker group analyzed using the method describe in Chapter 2. Table 3-11 shows the number of circuit breakers in-service and removed from service.

Table 3-11
Circuit breaker Group Data 500 kV Gas

Group	In-service	Removed from Service
500 kV Gas	100	4

Age Demographics 500 kV Gas

Figures 3-81 and 3-82 show the age demographics for both in service and removed from service circuit breaker units.

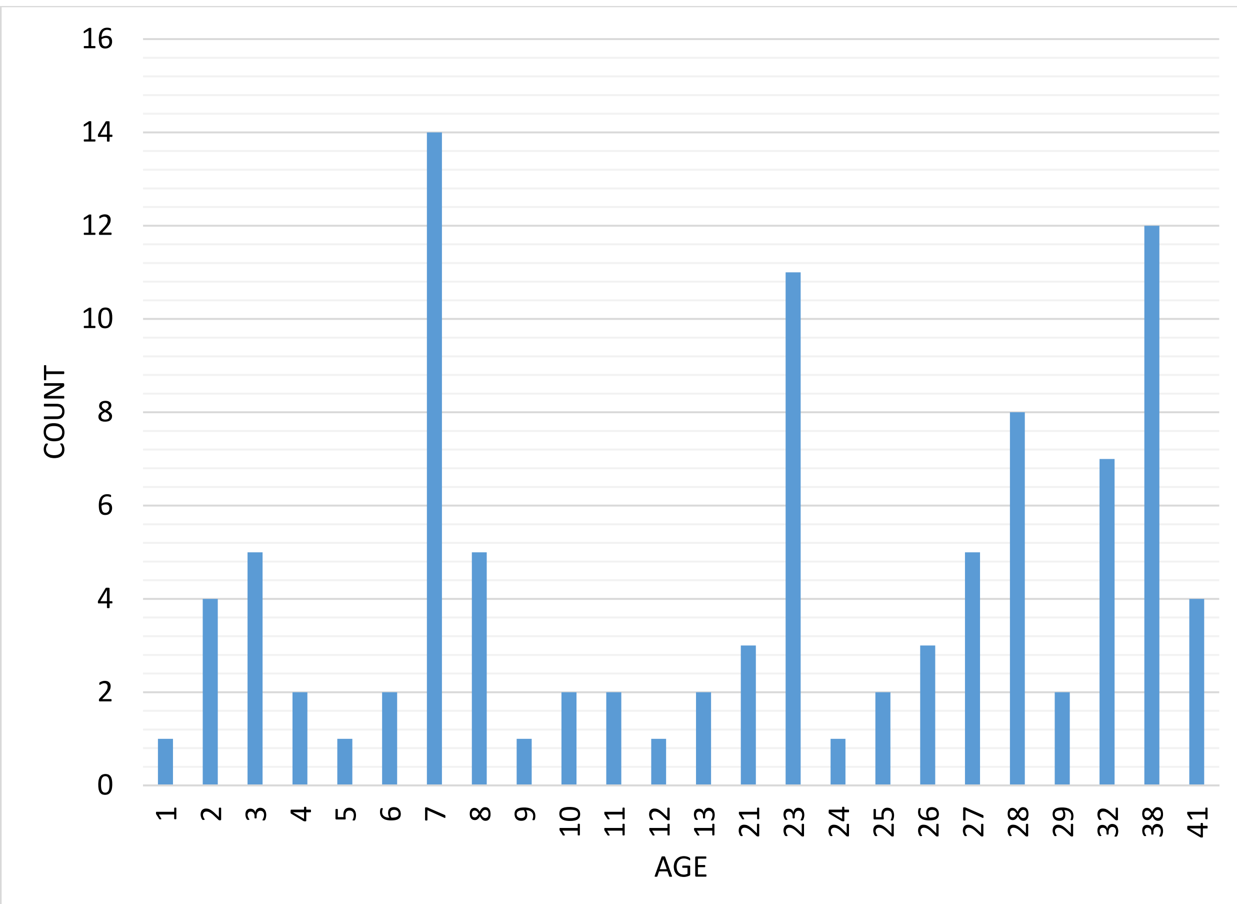

Figure 3-81
Age Demographics In-service 500 kV Gas

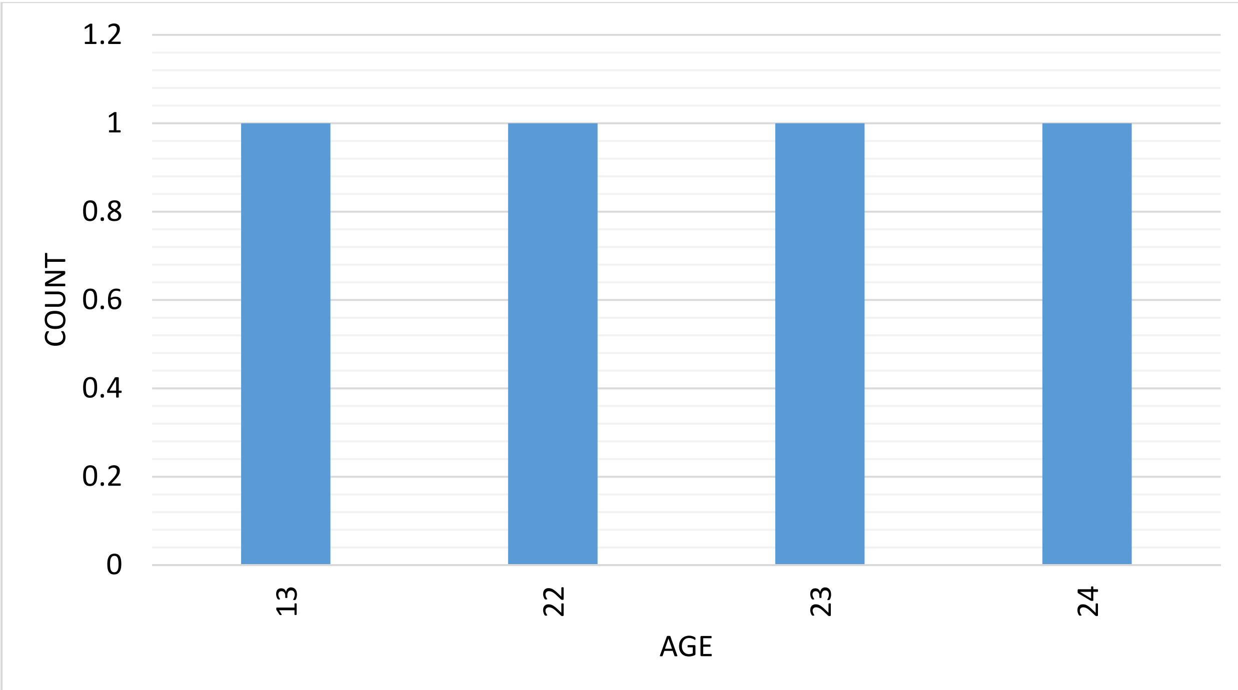

Figure 3-82
Age Demographics Removed From Service 500 kV Gas

Figures 3-83 and 3-84 show the Service Eras and Service Ages of the 500 kV Gas circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 2000. The small number of removal data points greatly decreases the confidence in the model.

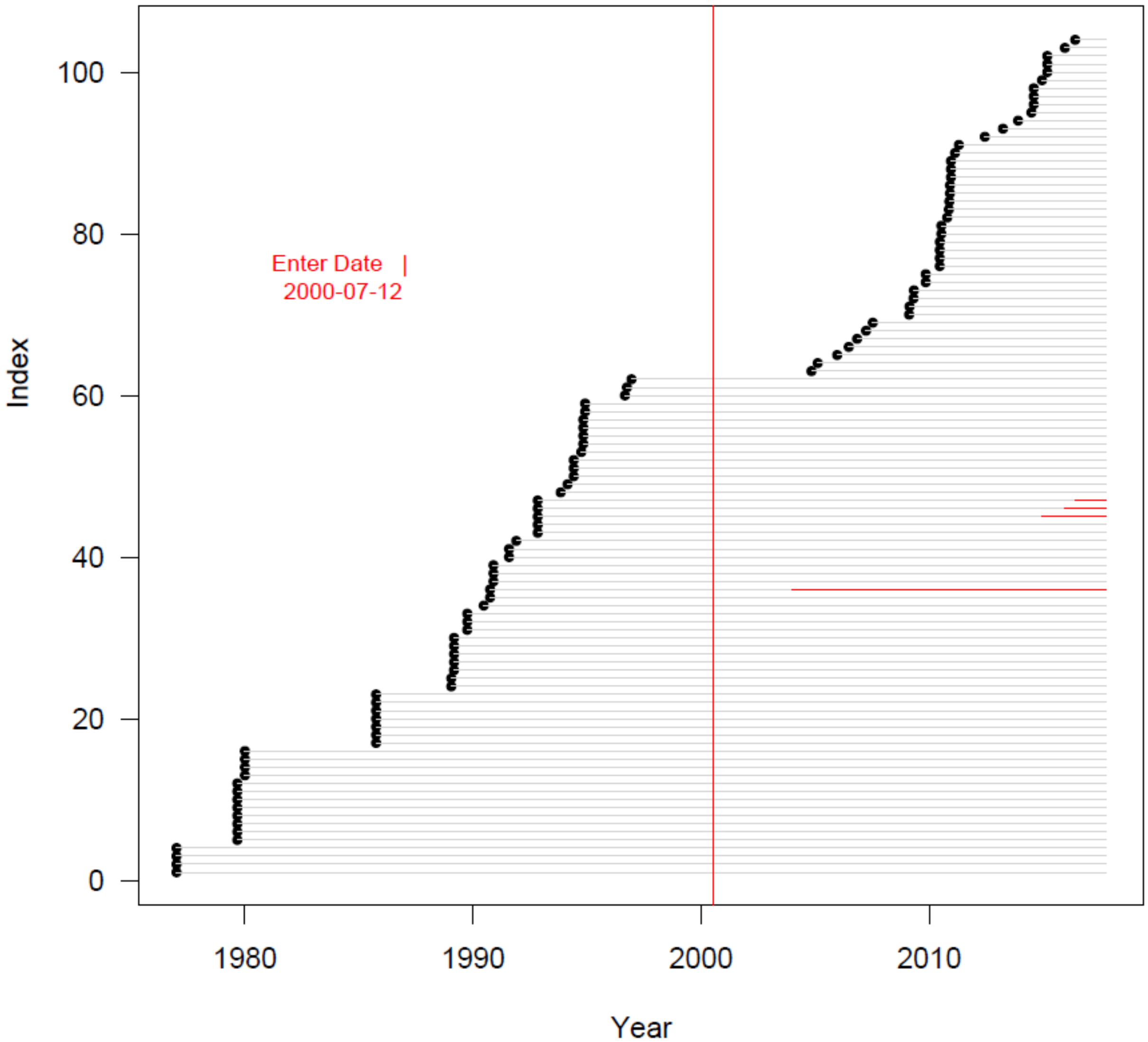

Figure 3-83
Service Eras 500 kV Gas

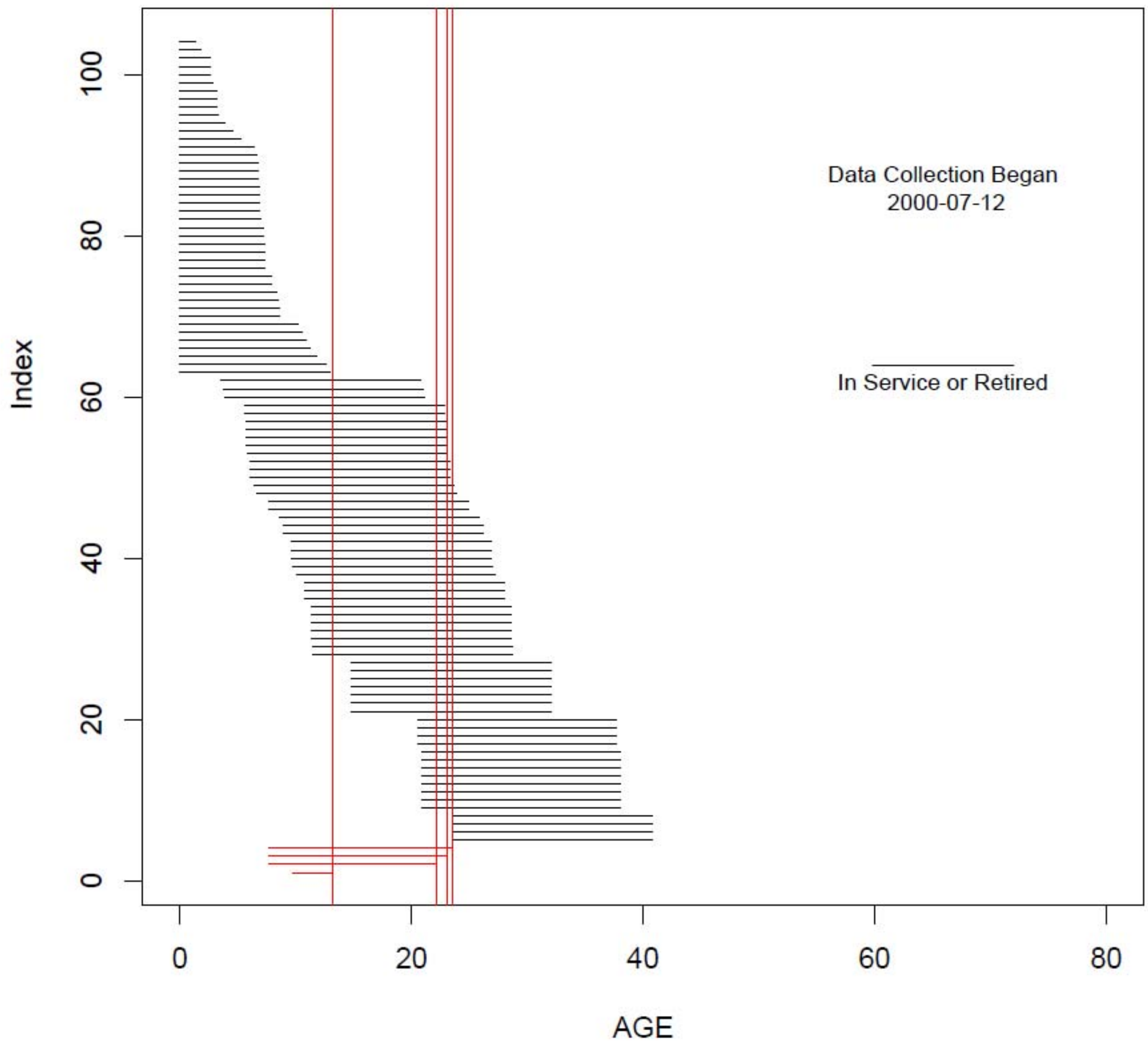

Figure 3-84
Service Ages 500 kV Gas

Removal Hazard Rate 500 kV Gas

Figure 3-85 shows the removal rate developed using the in-service and removed from service data provided for the 500 kV Gas circuit breaker. In the figure, probability of a 10 year old circuit breaker being removed in its next year of life ranges from 0.03% to 0.5%. For a 20 year old circuit breaker the probability of being removed in its next year of life ranges from 0.08% to 0.6%. Note the 95% confidence intervals. The bands become larger above age 20, reflecting the sparse number of recorded removals in these regions.

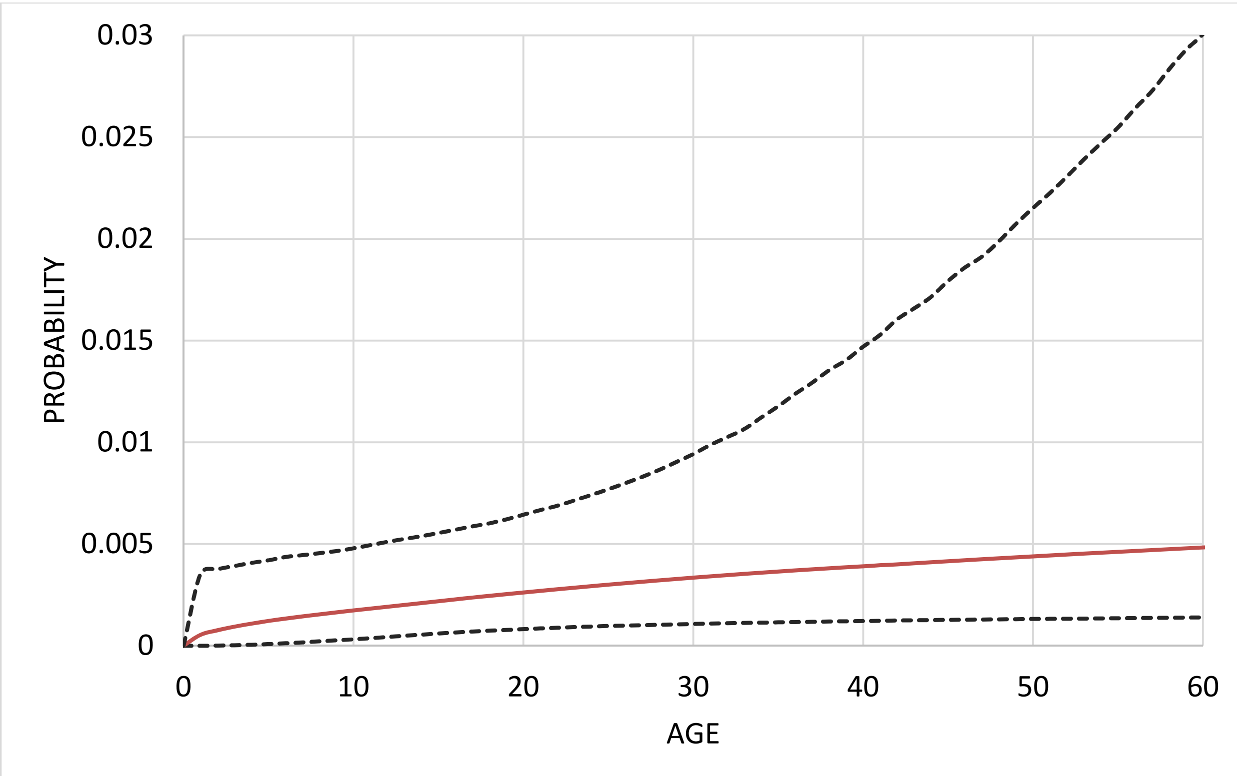

Figure 3-85
Removal Rate 500 kV Gas

Survival Function 500 kV Gas

Figure 3-86 shows the survival function developed using the in-service and removed from service data provided for the 500 kV Gas circuit breaker group. In the figure, the mean probability of a 20 year old circuit breaker surviving (not being removed) in its next year of life ranges from 91% to 99%.

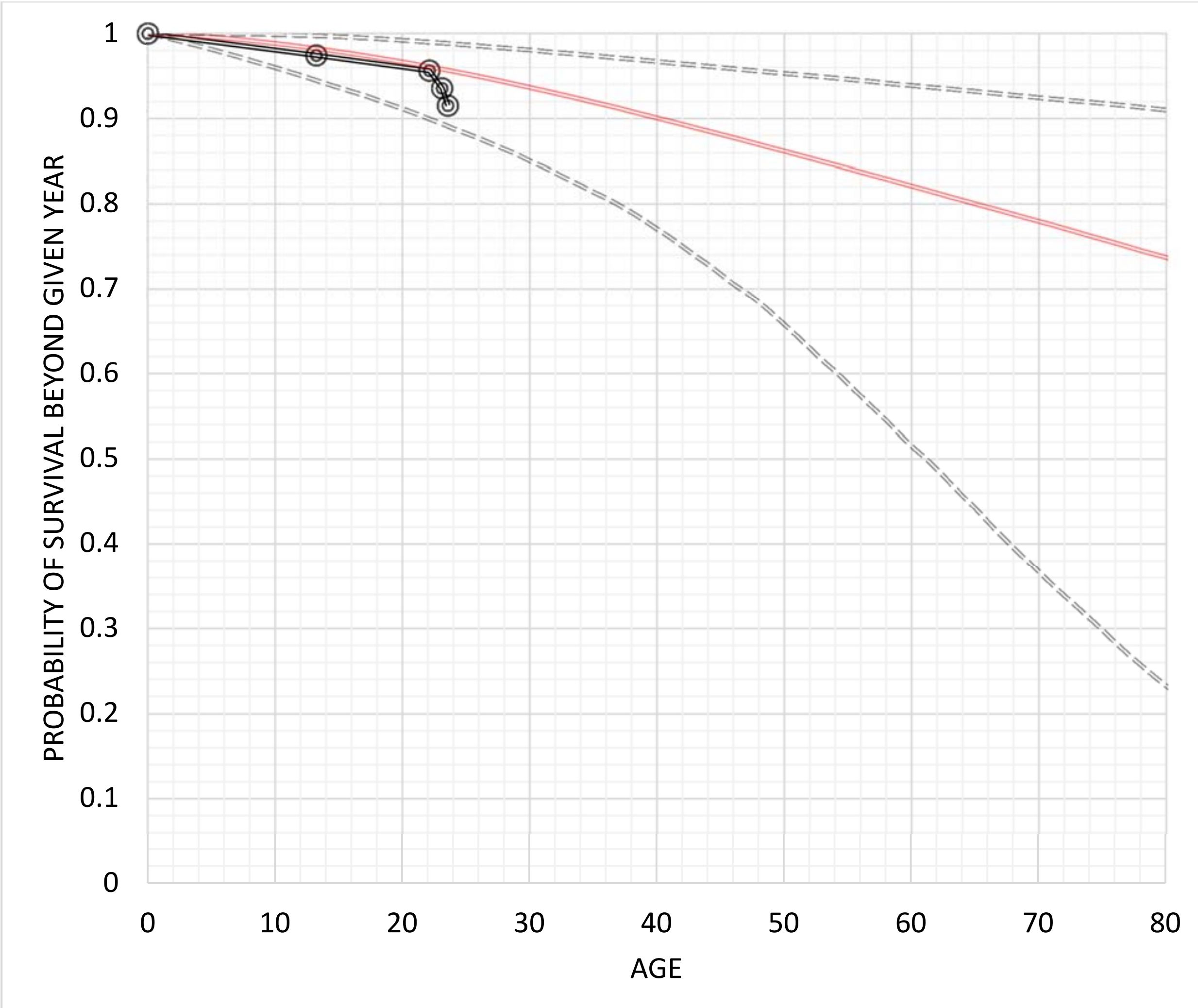

Figure 3-86
Survival Function 500 kV Gas

Forecasting Removals

Figures 3-87 and 3-88 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-87. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 2 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 2 or fewer. Figure 3-88 presents the cumulative results combining each year of the five year period.

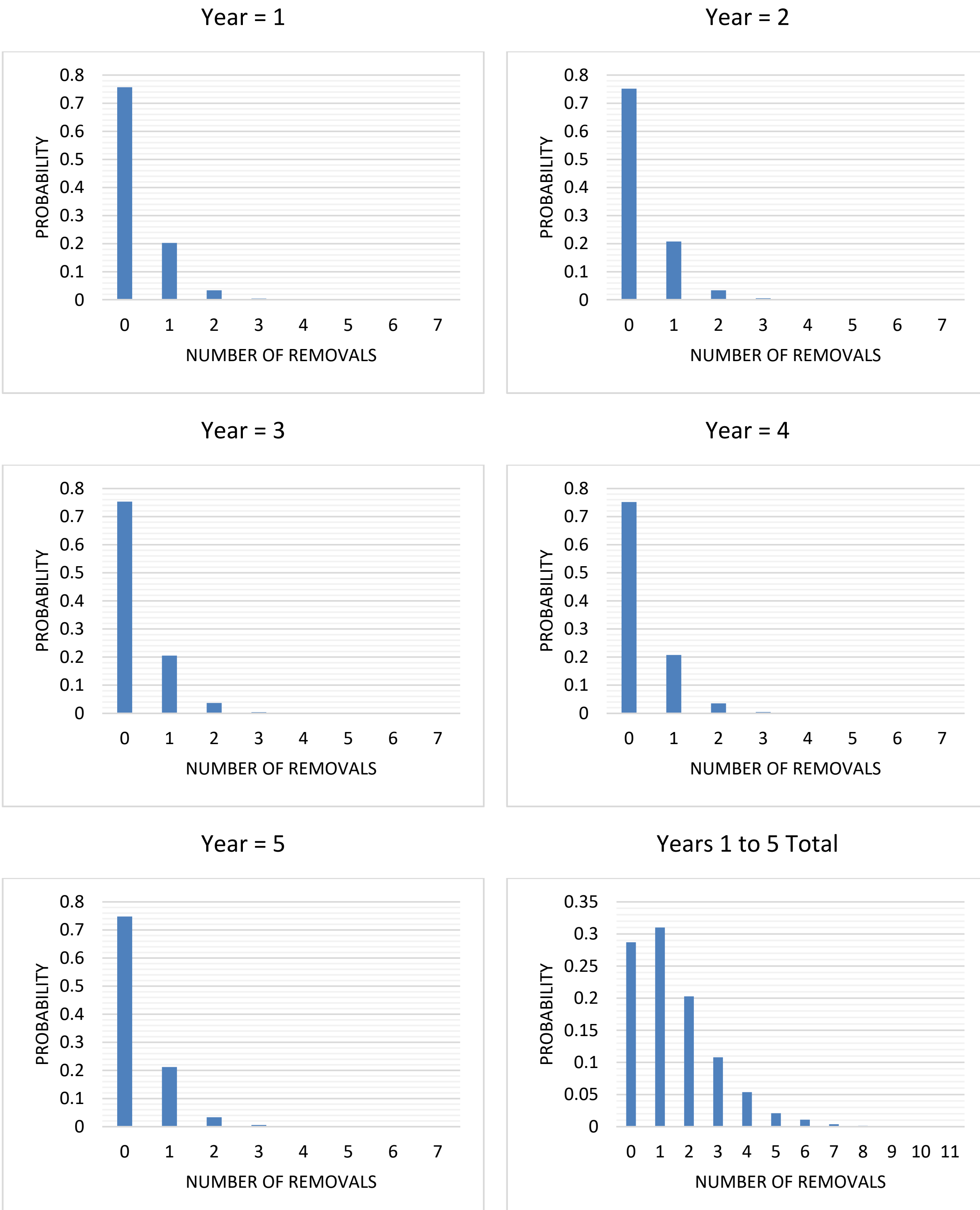

Figure 3-87
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 500 kV Gas

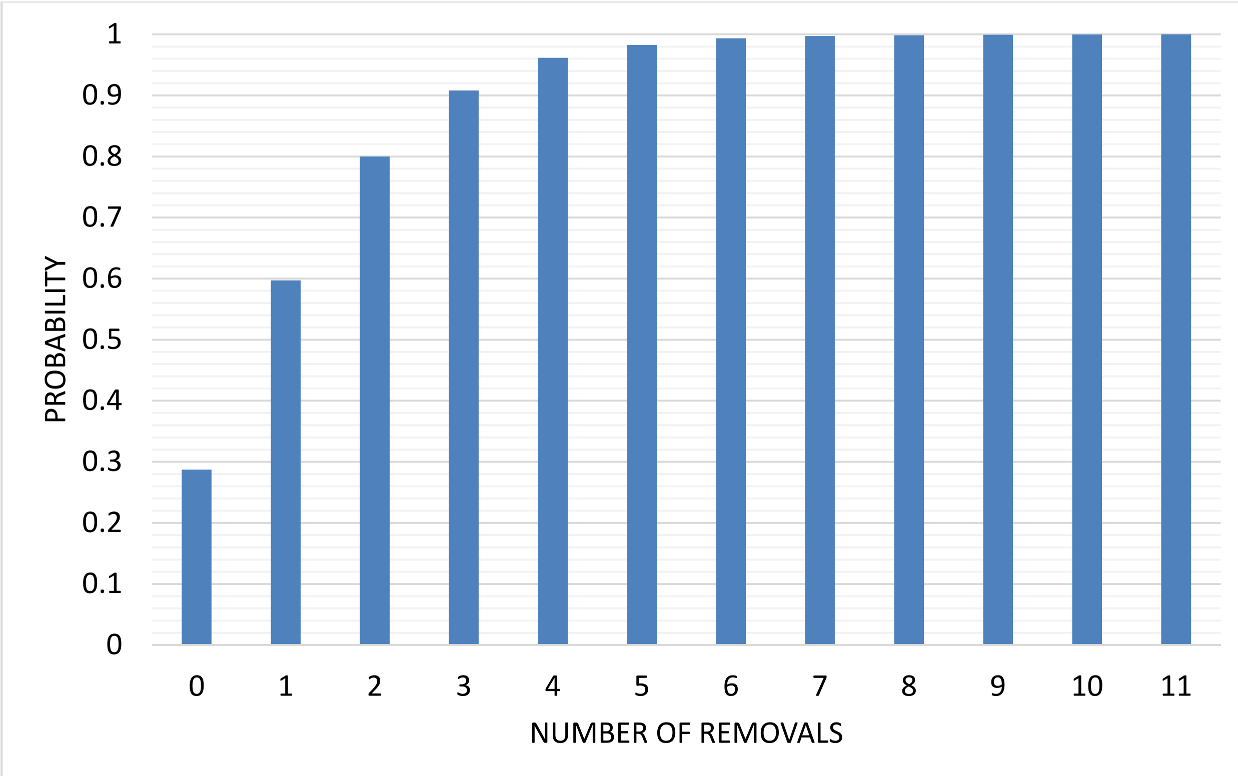

Figure 3-88
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 500 kV Gas

500 kV Air Blast Removal Analysis

The following provides the results of the 500 kV Air Blast circuit breaker group analyzed using the method describe in Chapter 2. Table 3-12 shows the number of circuit breakers in-service and removed from service.

Table 3-12
Circuit breaker Group Data 500 kV Air Blast

Group	In-service	Removed from Service
500 kV Air Blast	47	13

Age Demographics 500 kV Air Blast

Figures 3-89 and 3-90 show the age demographics for both in service and removed from service circuit breaker units.

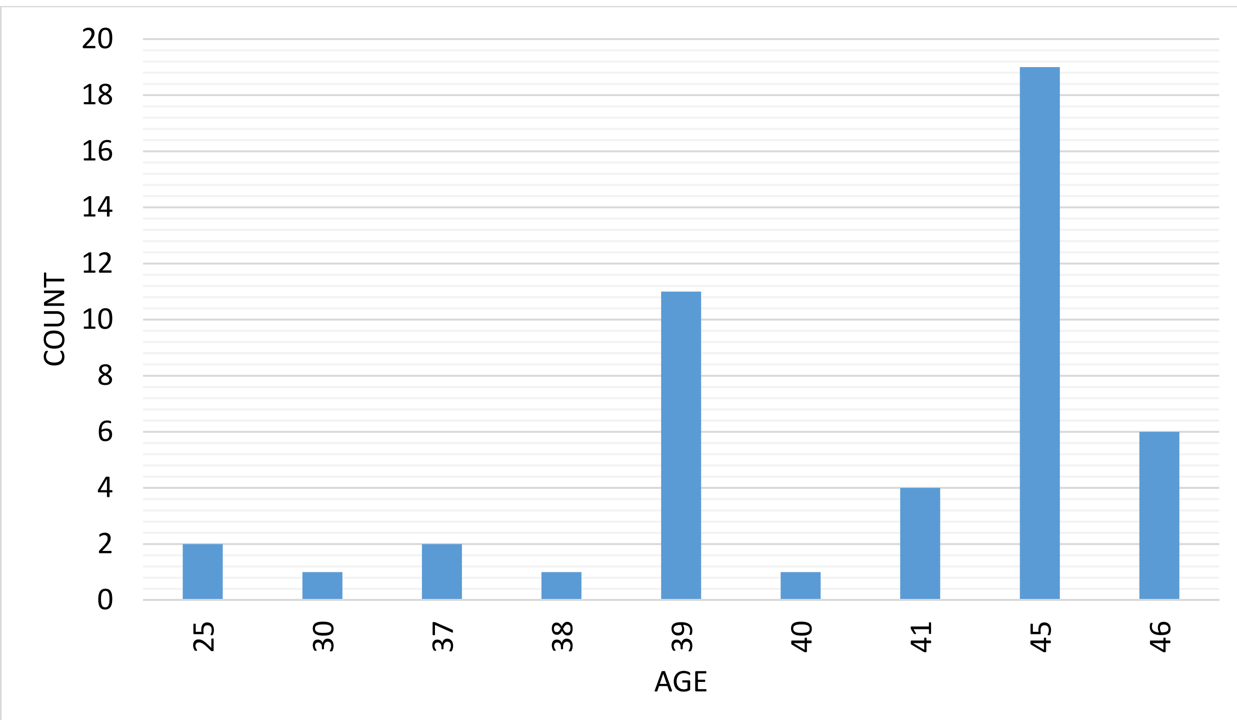

Figure 3-89
Age Demographics In-service 500 kV Air Blast

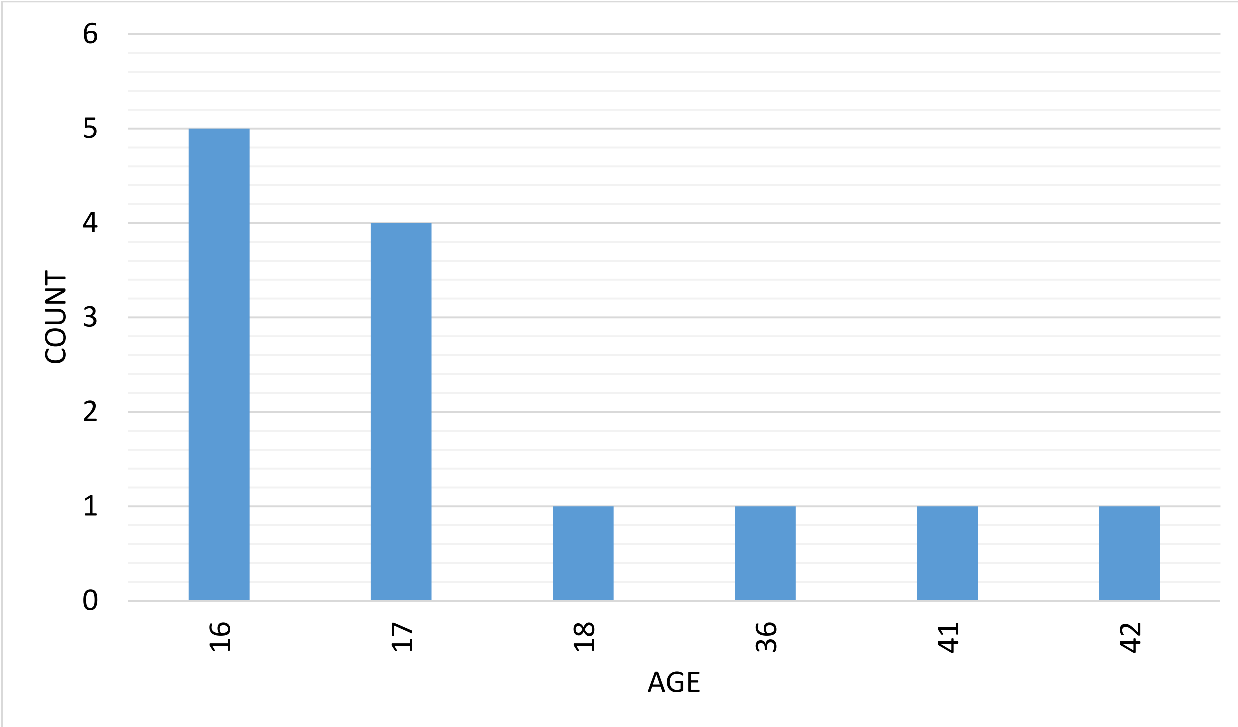

Figure 3-90
Age Demographics Removed From Service 500 kV Air Blast

Figures 3-91 and 3-92 show the Service Eras and Service Ages of the 500 kV Air Blast circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1995. The large number of breakers removed at the relatively young ages of 16 and 17 suggests that these removals were for some unusual (and unknown) reason. Consequently the validity of the model derived from this data and the subsequent removal projections may be not well supported by the historical data.

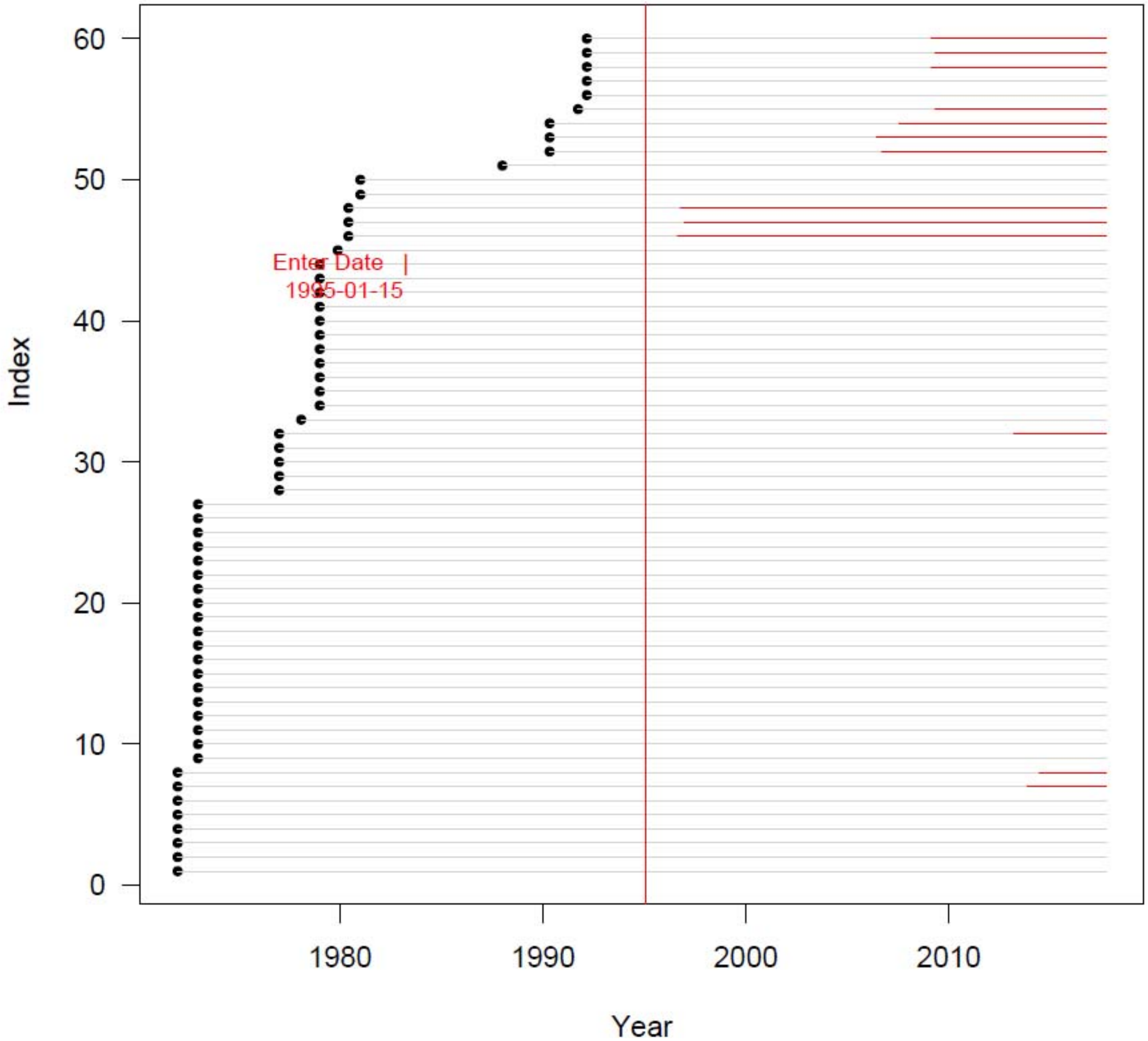

Figure 3-91
Service Eras 500 kV Air Blast

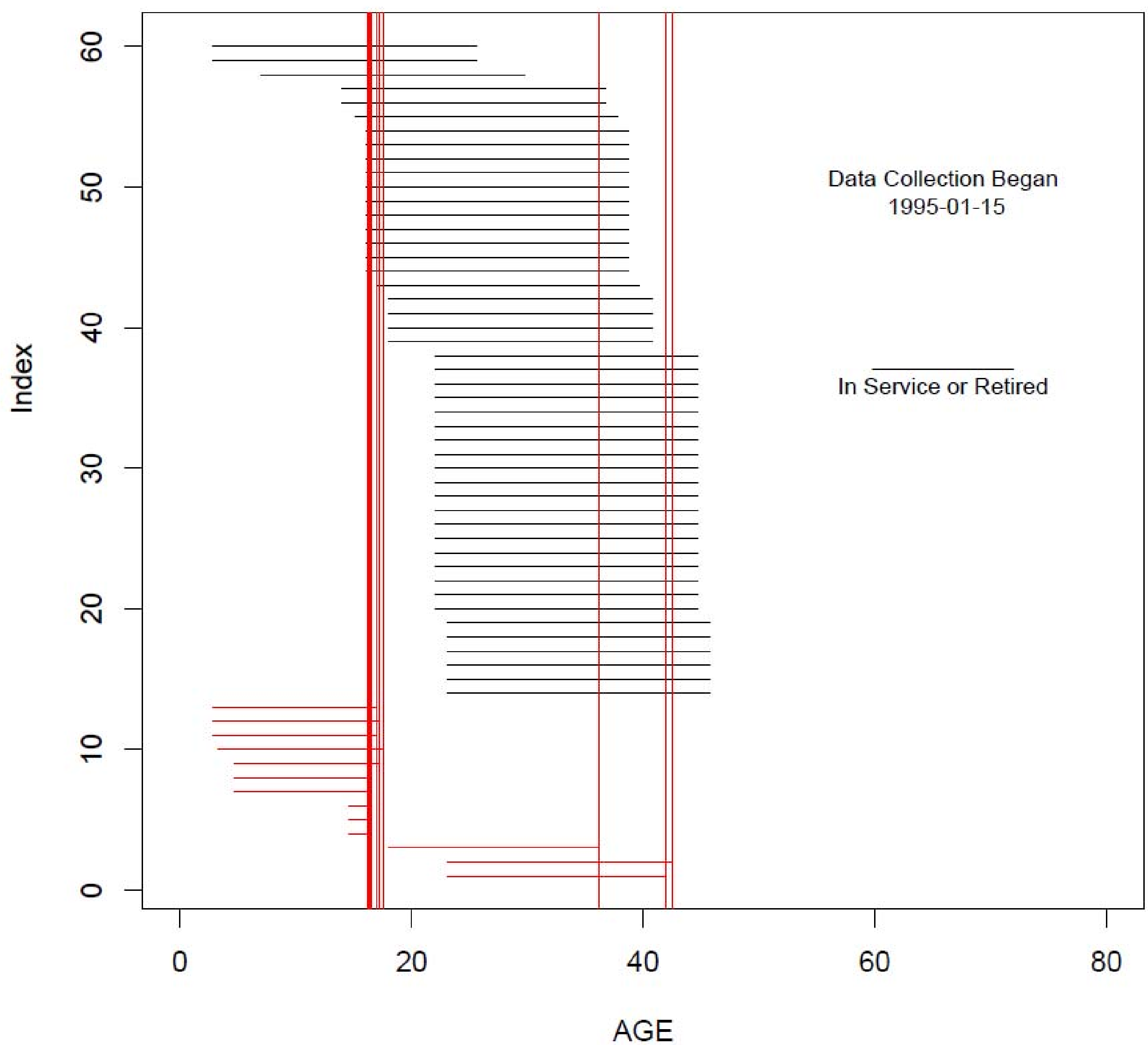

Figure 3-92
Service Ages 500 kV Air Blast

Removal Hazard Rate 500 kV Air Blast

Figure 3-93 shows the removal rate developed using the in-service and removed from service data provided for the 500 kV Air Blast circuit breaker. In the figure, probability of a 10 year old circuit breaker being removed in its next year of life ranges from 0.3% to 1.3%.

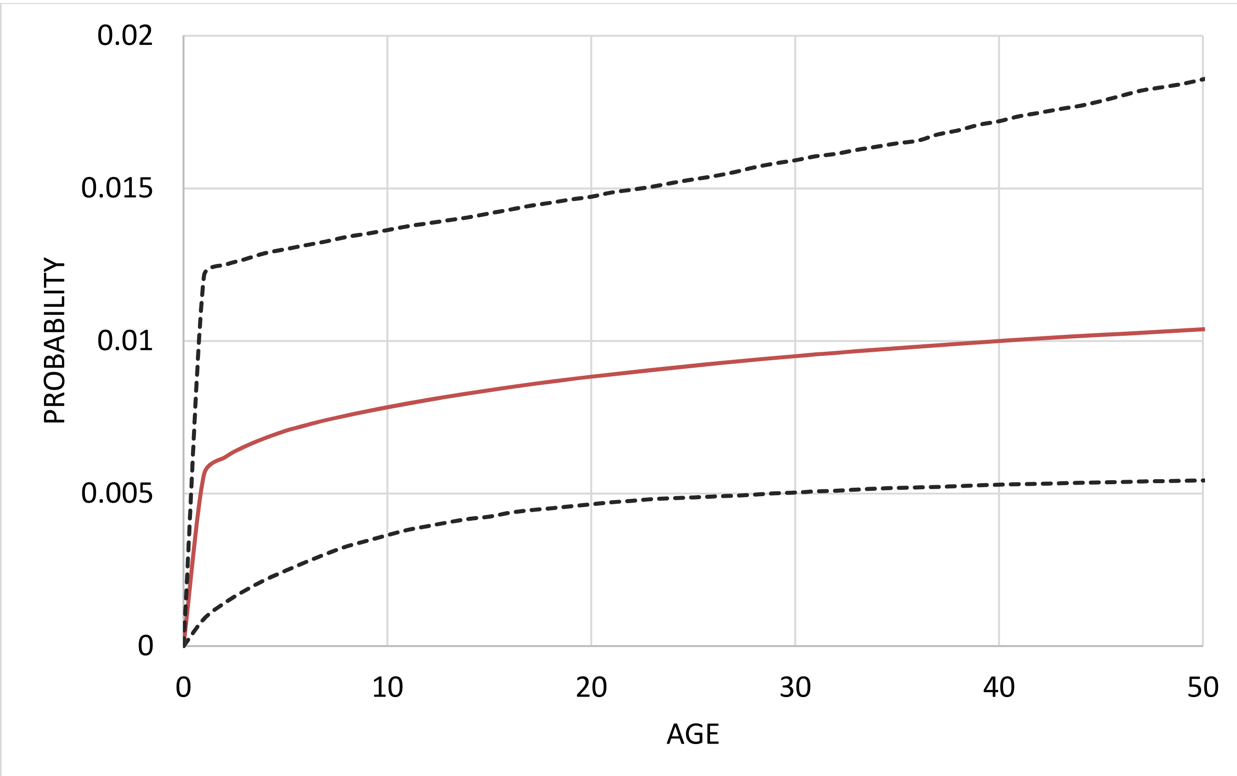

Figure 3-93
Removal Rate 500 kV Air Blast

Survival Function 500 kV Air Blast

Figure 3-94 shows the survival function developed using the in-service and removed from service data provided for the 500 kV Air Blast circuit breaker group. In the figure, the mean probability of a 20 year old circuit breaker surviving (not being removed) in its next year of life ranges from 76% to 93%.

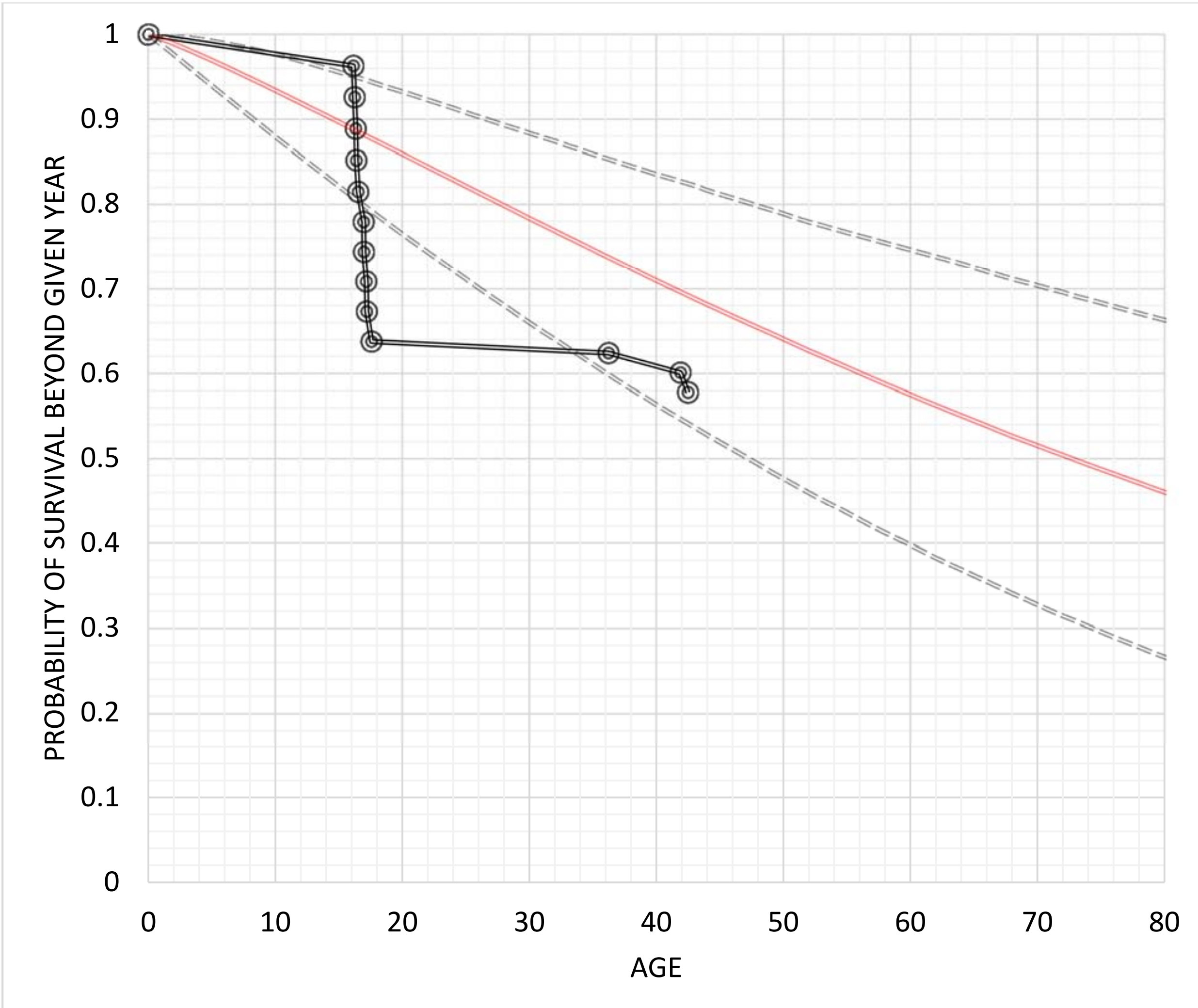

Figure 3-94
Survival Function 500 kV Air Blast

Forecasting Removals

Figures 3-95 and 3-96 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-95. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 2 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 2 or fewer. Figure 3-96 presents the cumulative results combining each year of the five year period.

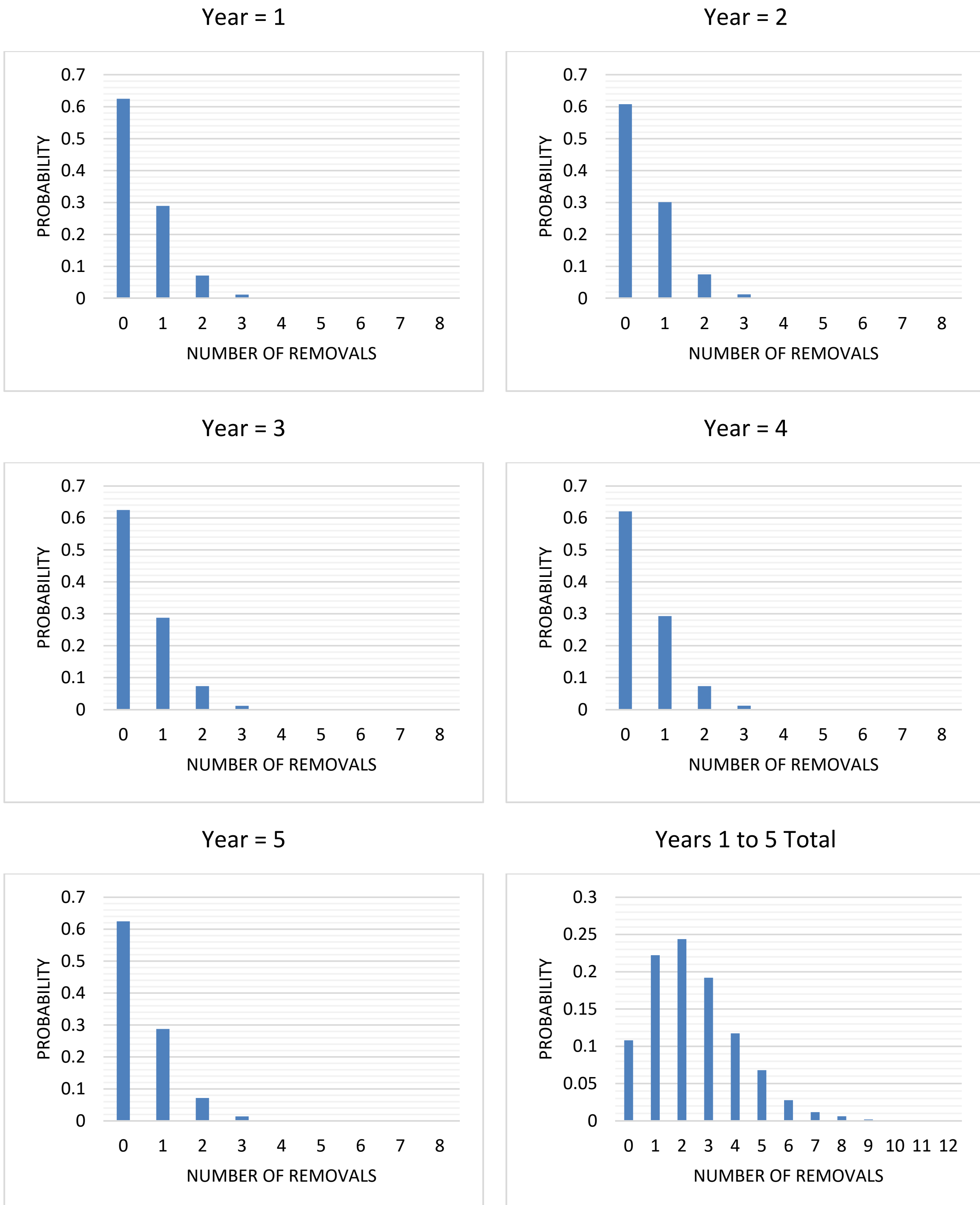

Figure 3-95
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 500 kV Air Blast

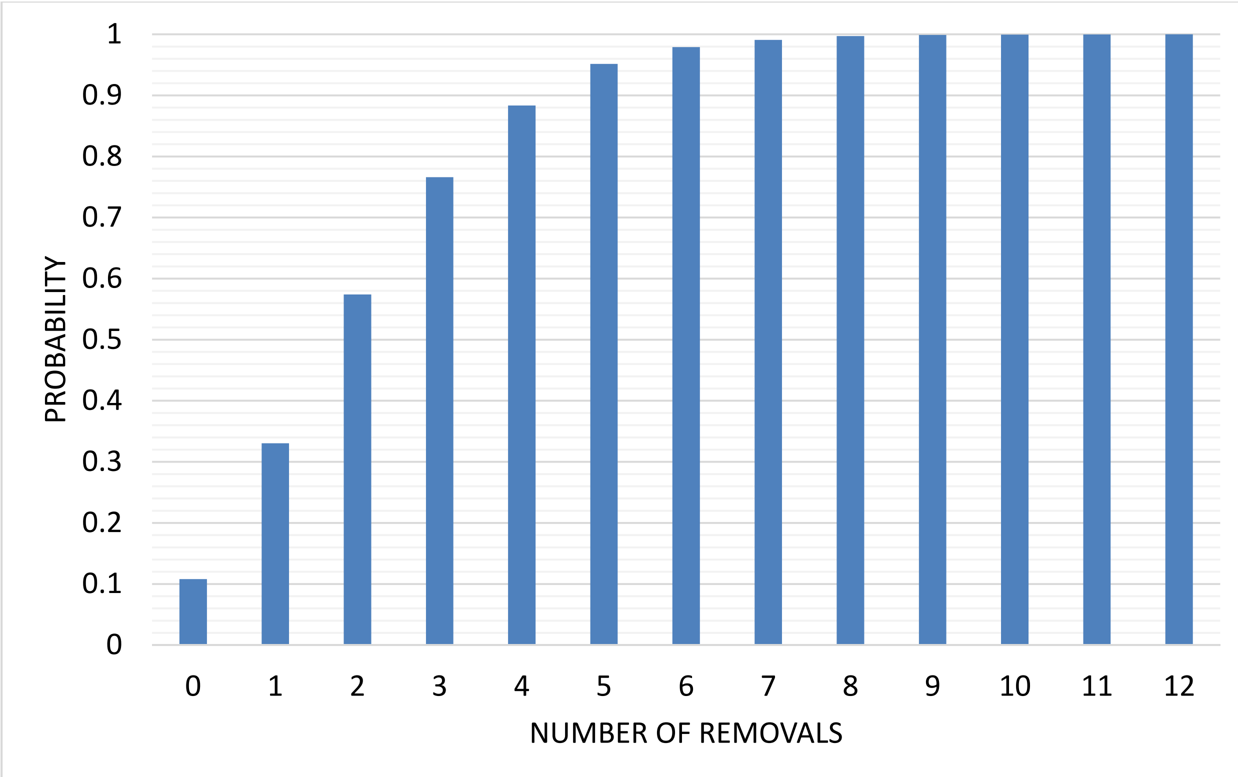

Figure 3-96
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 500 kV Air Blast

230 kV Air Blast Removal Analysis

The following provides the results of the 230 kV Air Blast circuit breaker group analyzed using the method describe in Chapter 2. Table 3-13 shows the number of circuit breakers in-service and removed from service.

Table 3-13
Circuit breaker Group Data 230 kV Air Blast

Group	In-service	Removed from Service
230 kV Air Blast	100	99

Age Demographics 230 kV Air Blast

Figures 3-97 and 3-98 show the age demographics for both in service and removed from service circuit breaker units.

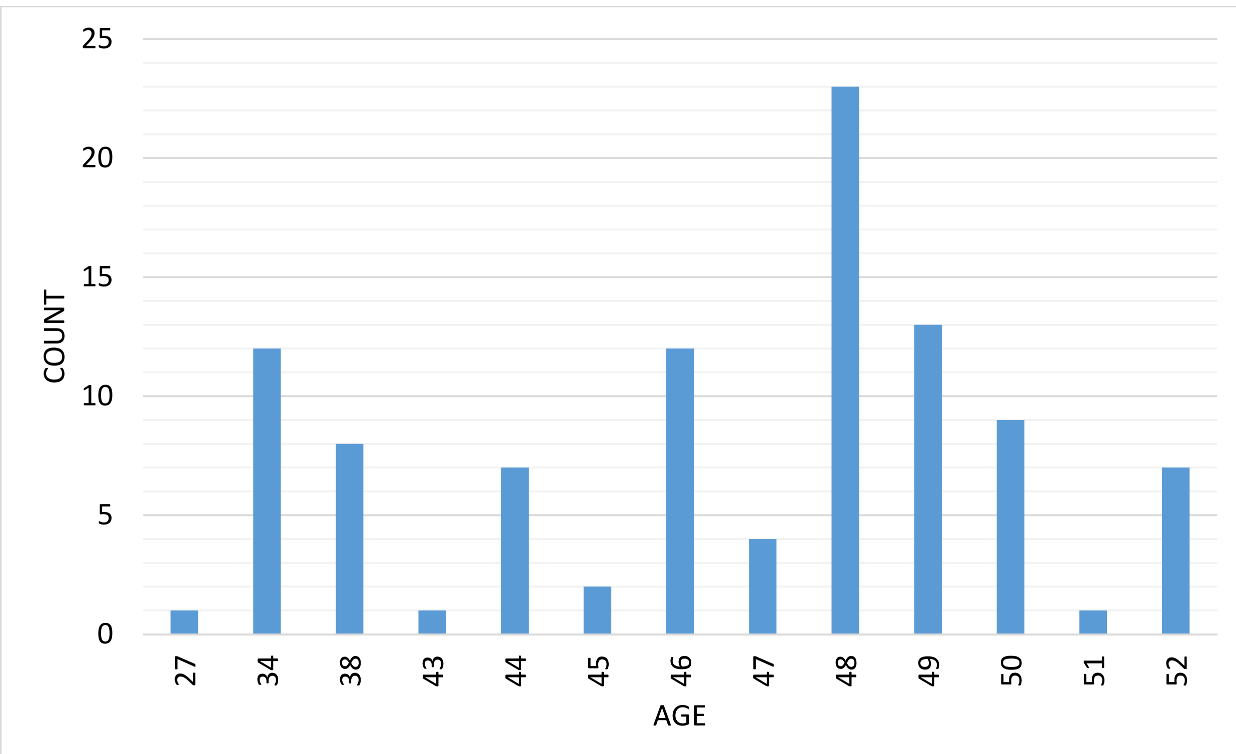

Figure 3-97
Age Demographics In-service 230 kV Air Blast

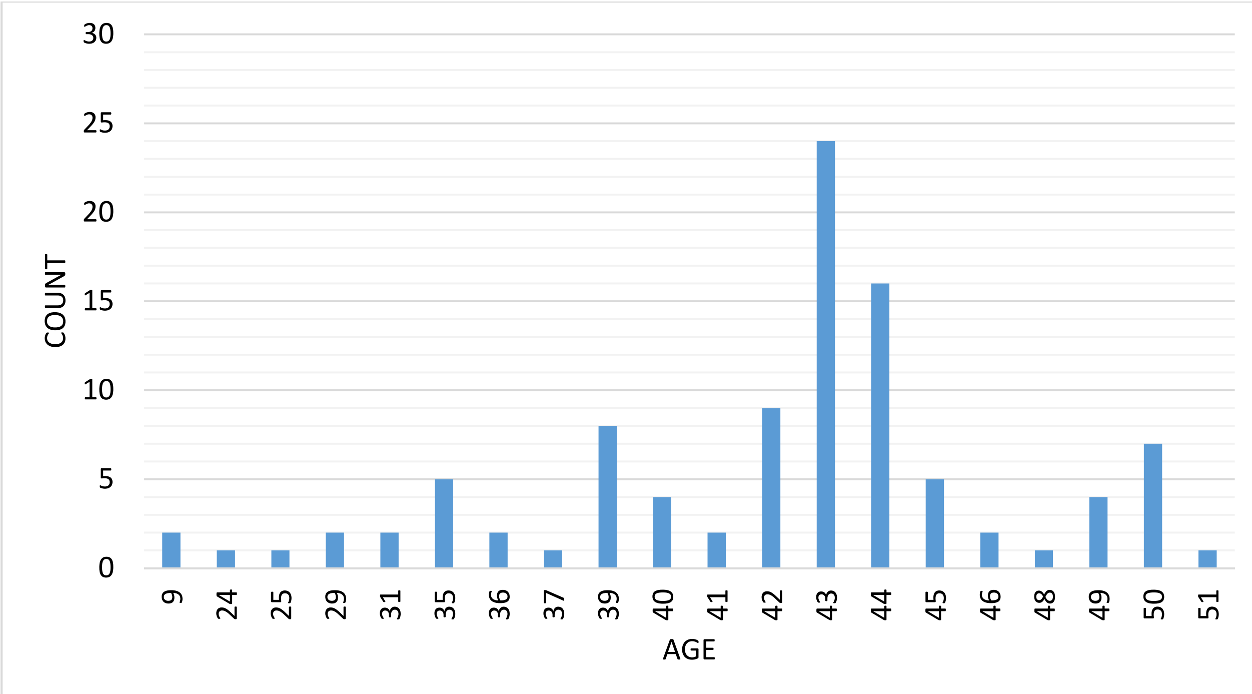

Figure 3-98
Age Demographics Removed From Service 230 kV Air Blast

Figures 3-99 and 3-100 show the Service Eras and Service Ages of the 230 kV Air Blast circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1994. The large number of breakers removed at the relatively young ages of 43 and 44 suggests that these removals were for some unusual (and unknown) reason. Consequently the validity of the model derived from this data and the subsequent removal projections may be not well supported by the historical data.

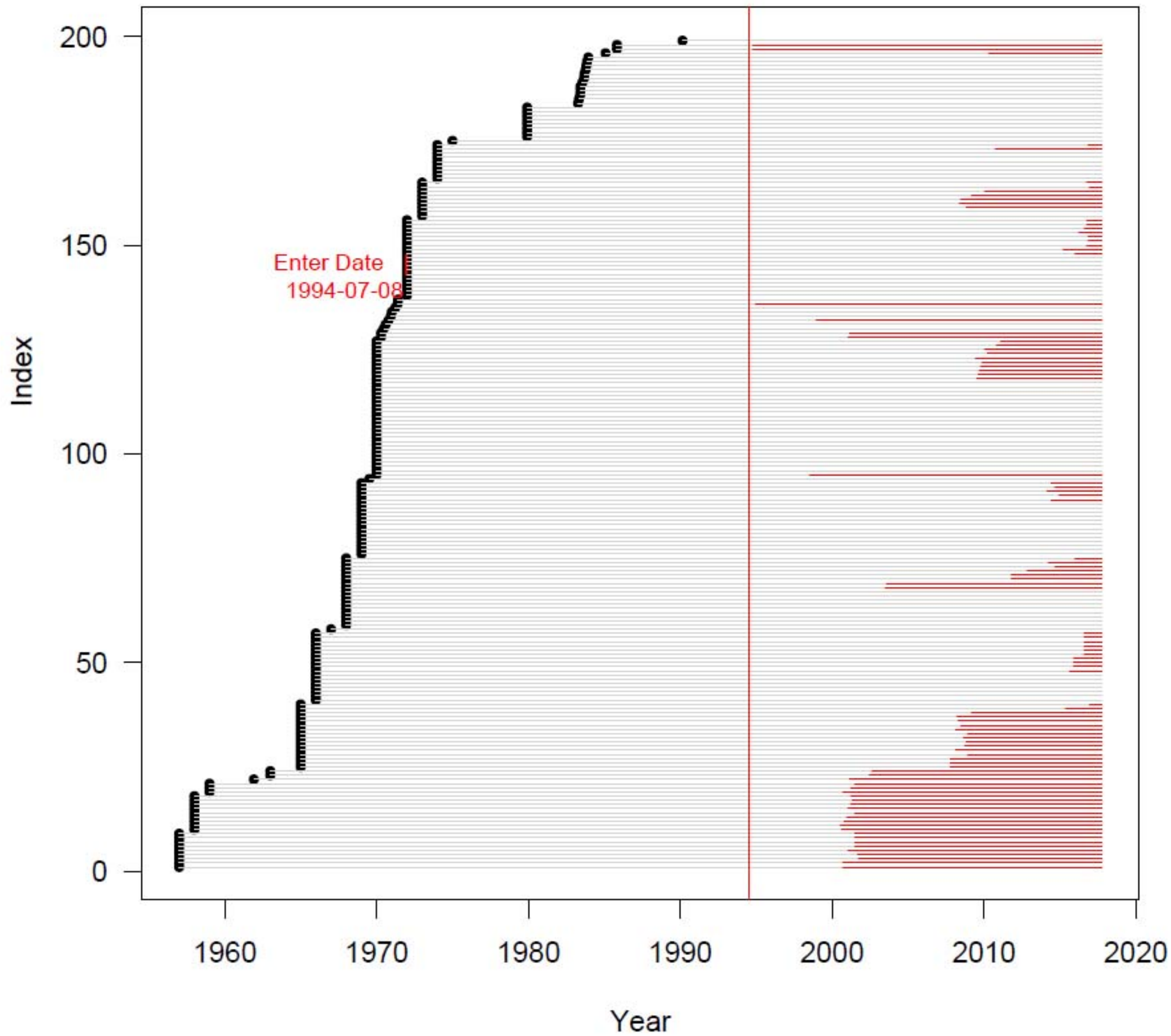

Figure 3-99
Service Eras 230 kV Air Blast

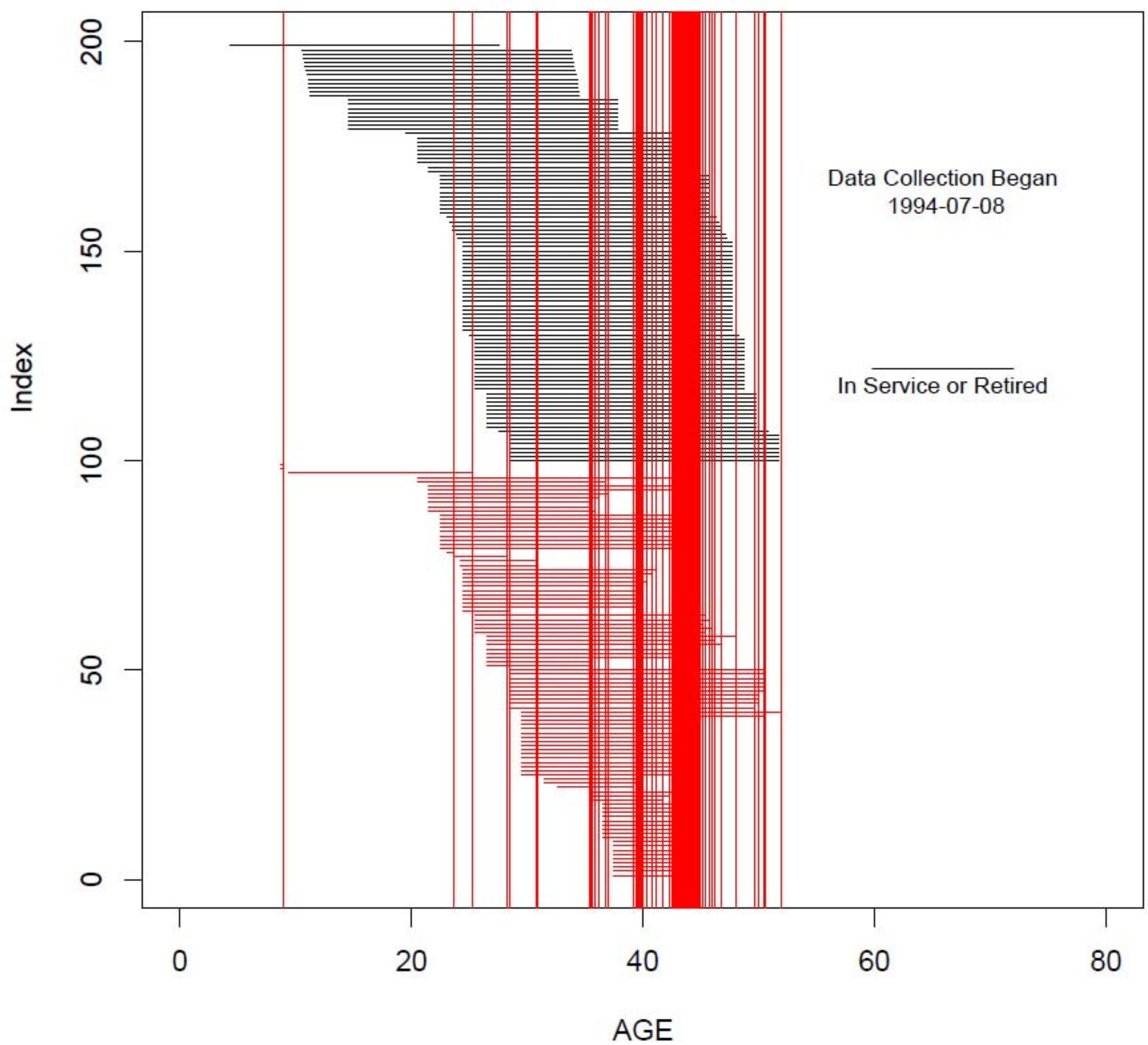

Figure 3-100
Service Ages 230 kV Air Blast

Removal Hazard Rate 230 kV Air Blast

Figure 3-101 shows the removal rate developed using the in-service and removed from service data provided for the 230 kV Air Blast circuit breaker. In the figure, probability of a 40 year old circuit breaker being removed in its next year of life ranges from 2.7% to 4.3%.

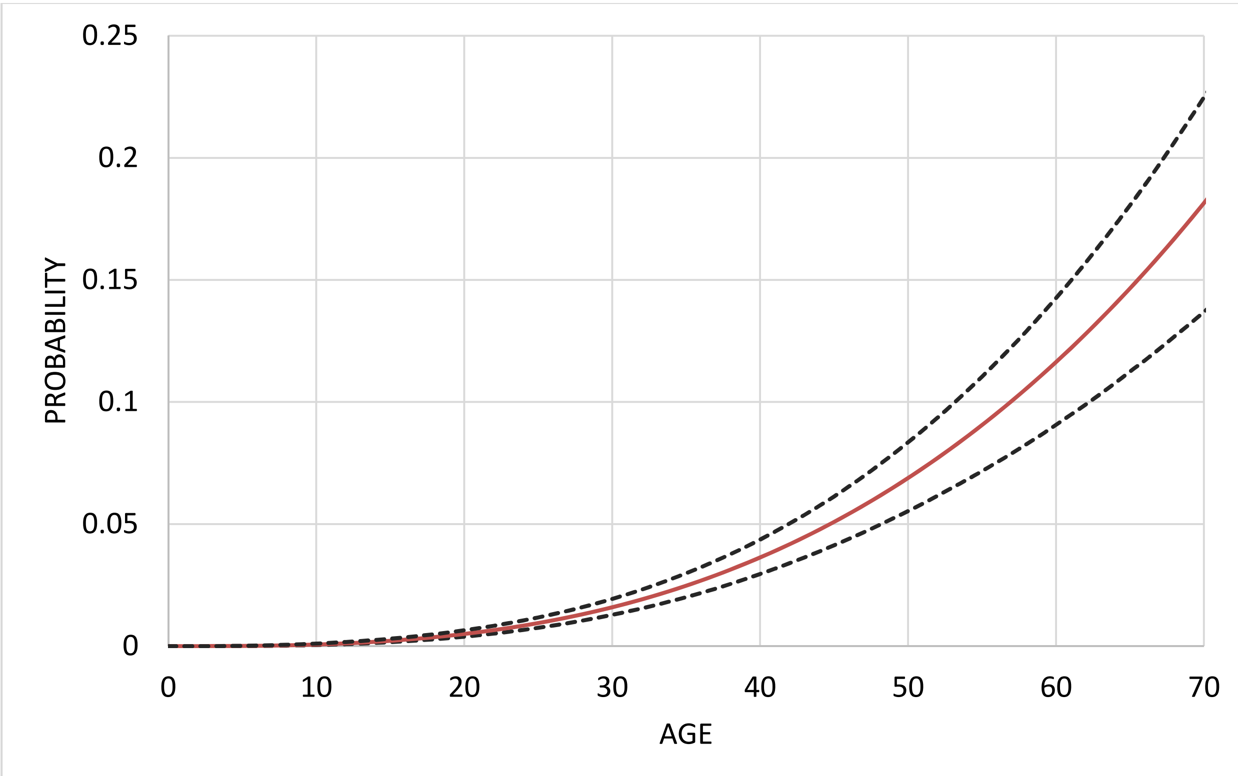

Figure 3-101
Removal Rate 230 kV Air Blast

Survival Function 230 kV Air Blast

Figure 3-102 shows the survival function developed using the in-service and removed from service data provided for the 230 kV Air Blast circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 63% to 73%.

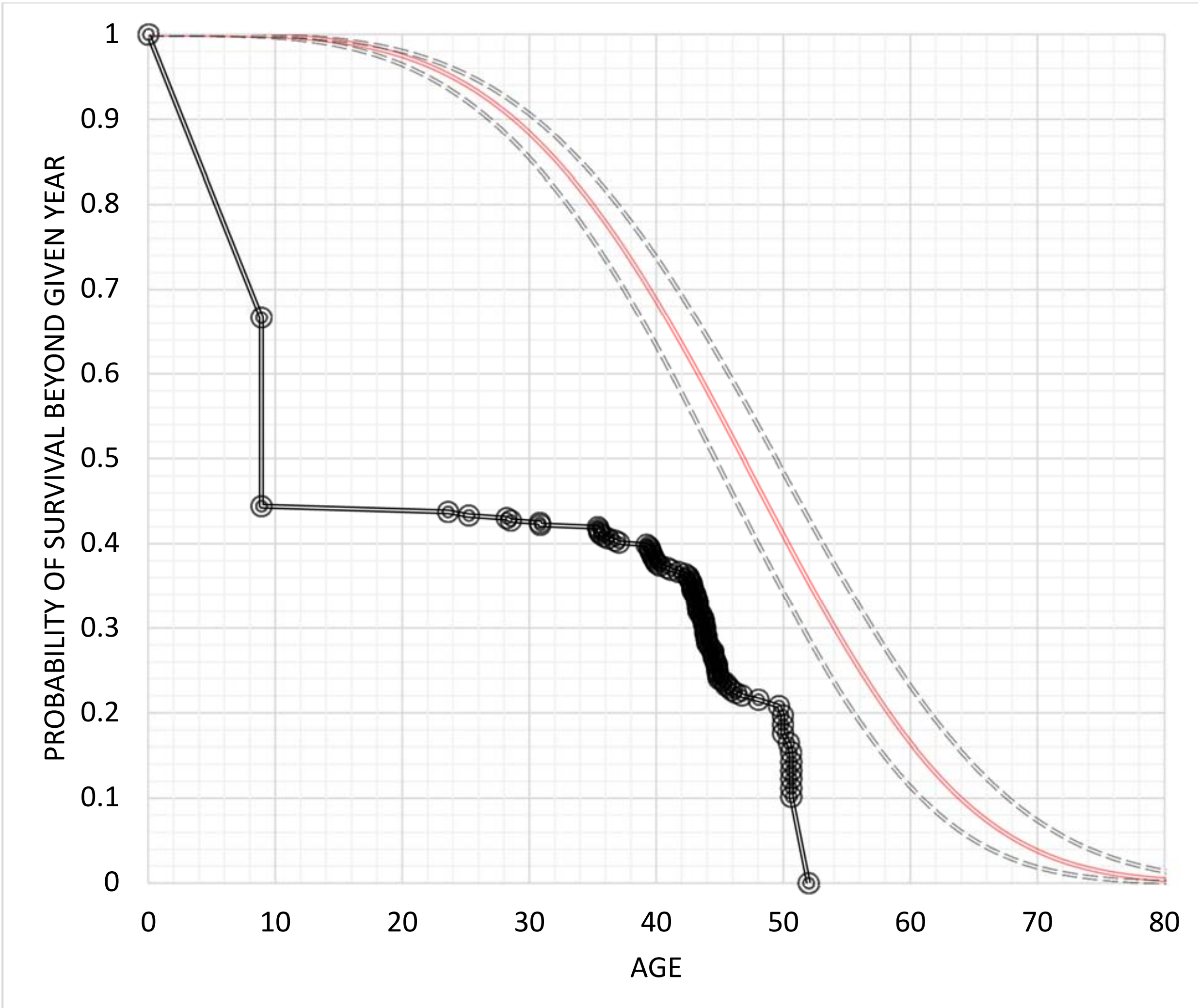

Figure 3-102
Survival Function 230 kV Air Blast

Forecasting Removals

Figures 3-103 and 3-104 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-103. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 11 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 11 or fewer. Figure 3-104 presents the cumulative results combining each year of the five year period.

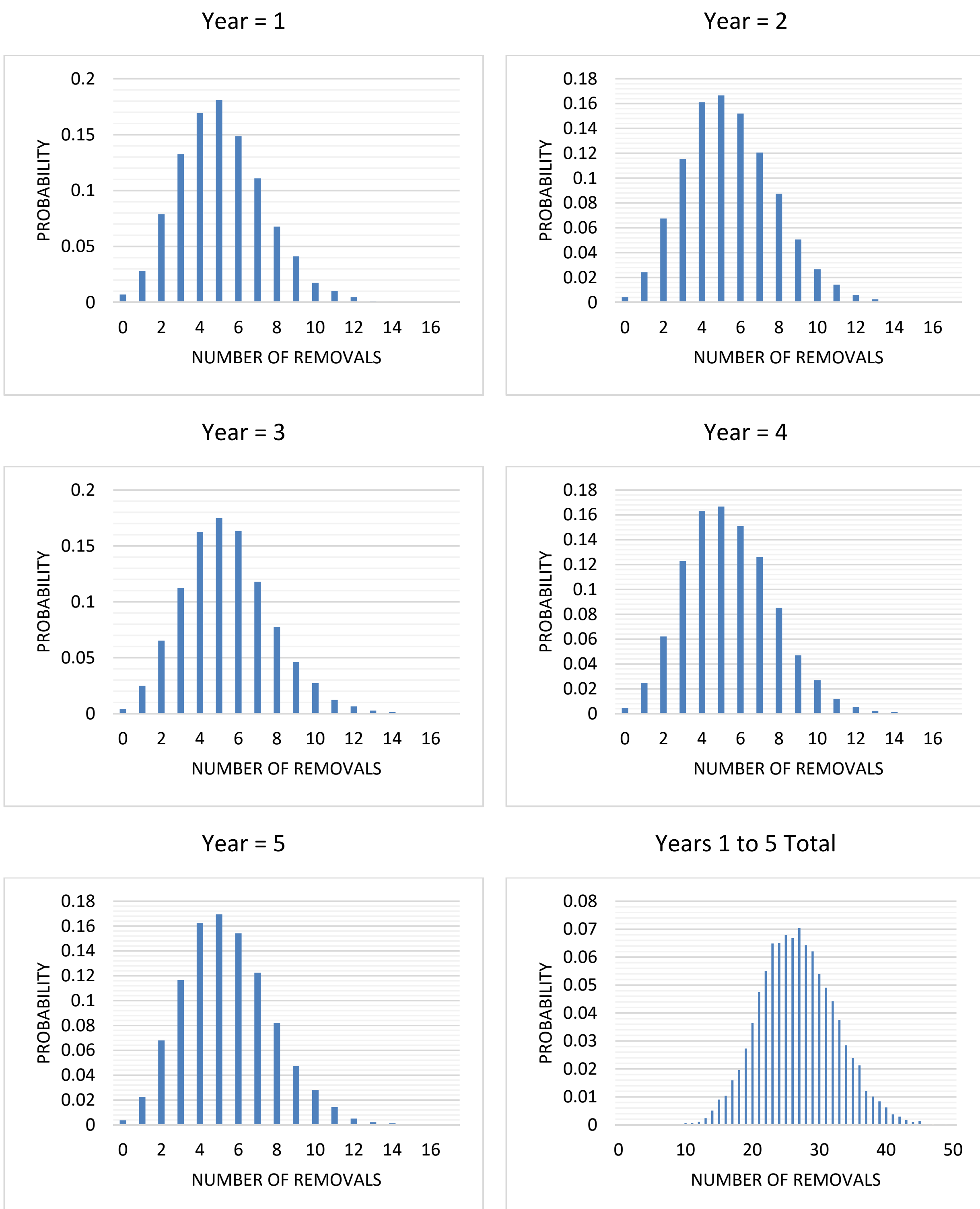

Figure 3-103
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 230 kV Air Blast

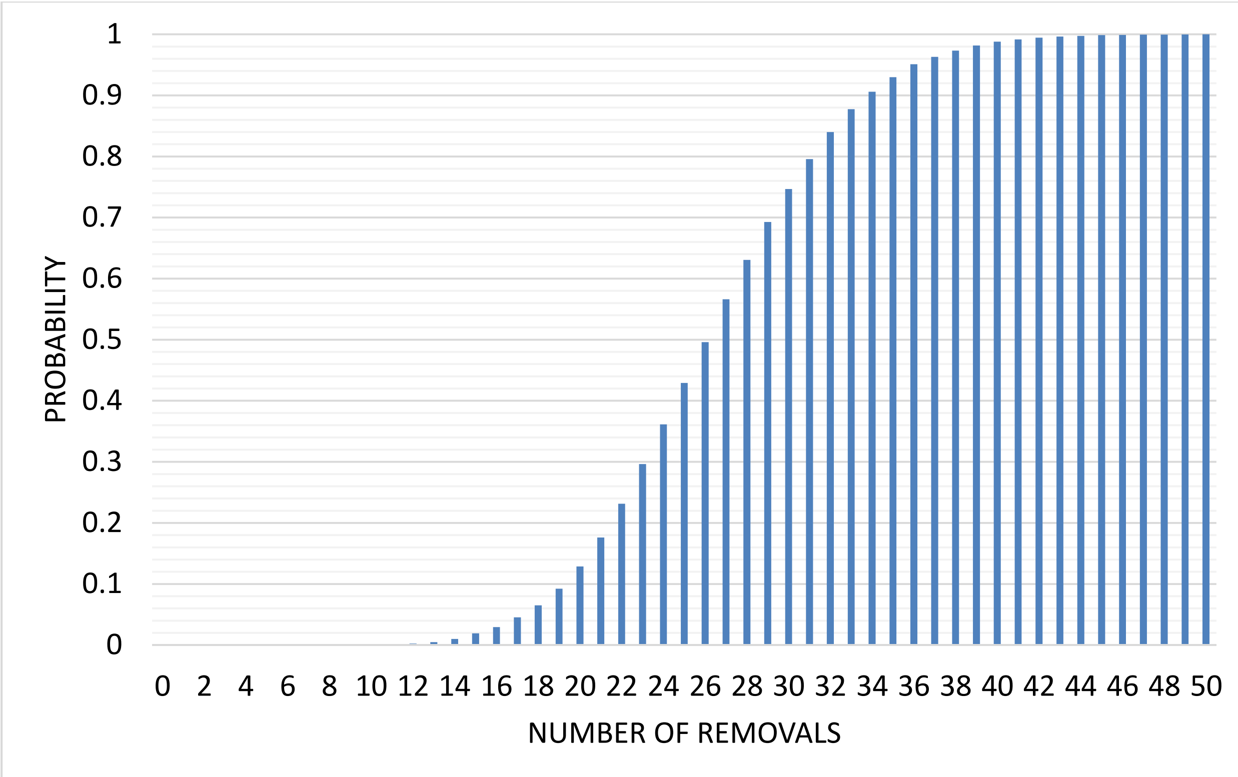

Figure 3-104
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 230 kV Air Blast

13 kV Air Magnetic Removal Analysis

The following provides the results of the 13 kV Air Magnetic circuit breaker group analyzed using the method describe in Chapter 2. Table 3-14 shows the number of circuit breakers in-service and removed from service.

Table 3-14
Circuit breaker Group Data 13 kV Air Magnetic

Group	In-service	Removed from Service
13 kV Air Magnetic	251	72

Age Demographics 13 kV Air Magnetic

Figures 3-105 and 3-106 show the age demographics for both in service and removed from service circuit breaker units.

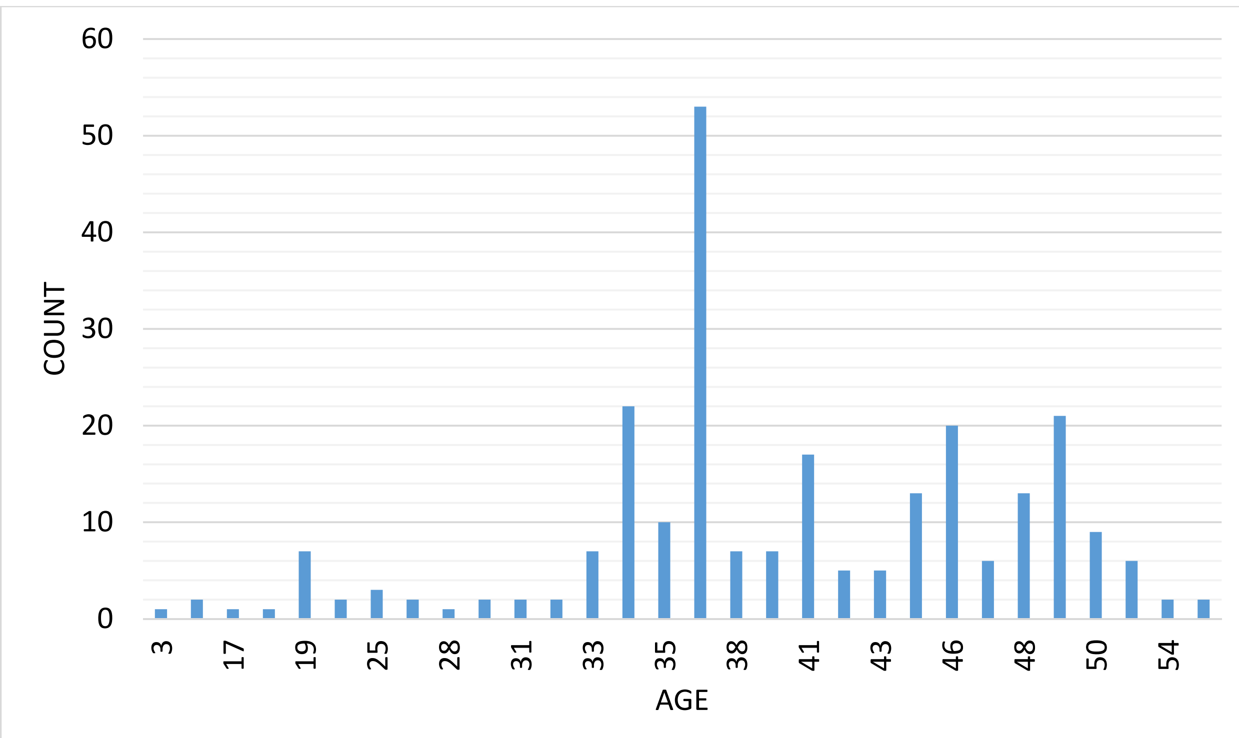

Figure 3-105
Age Demographics In-service 13 kV Air Magnetic

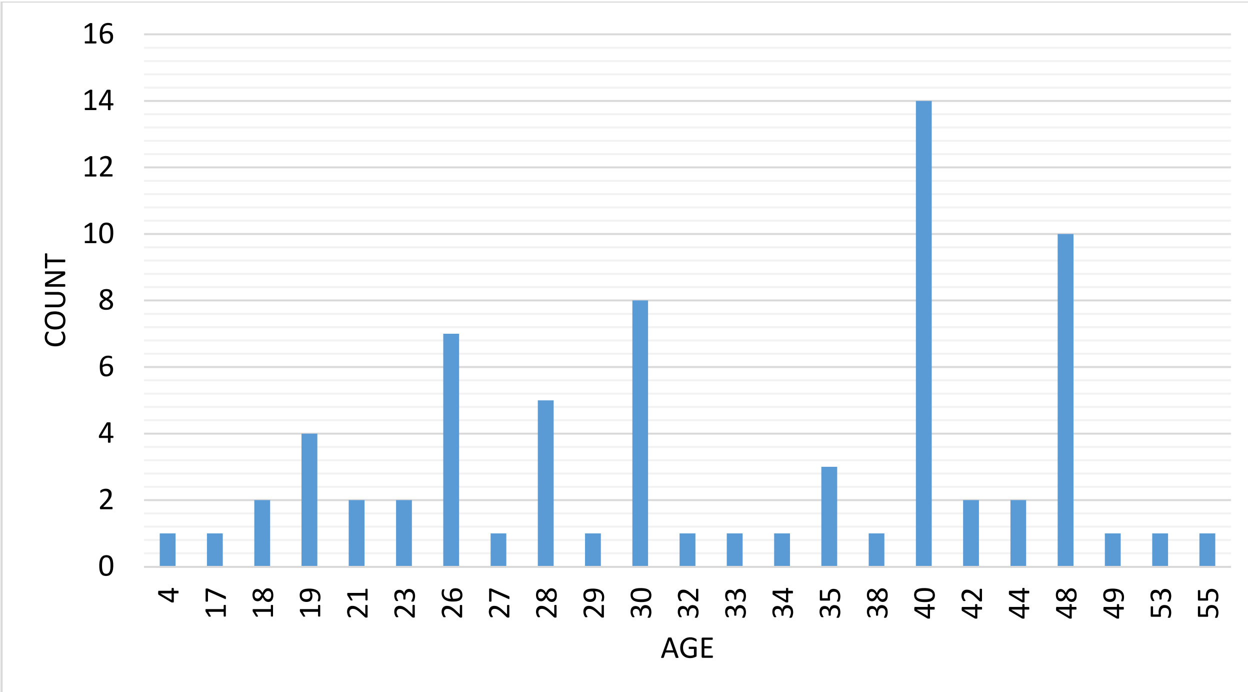

Figure 3-106
Age Demographics Removed From Service 13 kV Air Magnetic

Figures 3-107 and 3-108 show the Service Eras and Service Ages of the 13 kV Air Magnetic circuit breaker group. The service eras and service ages plots shows the observation period for this circuit breaker group where the observation period began in 1983.

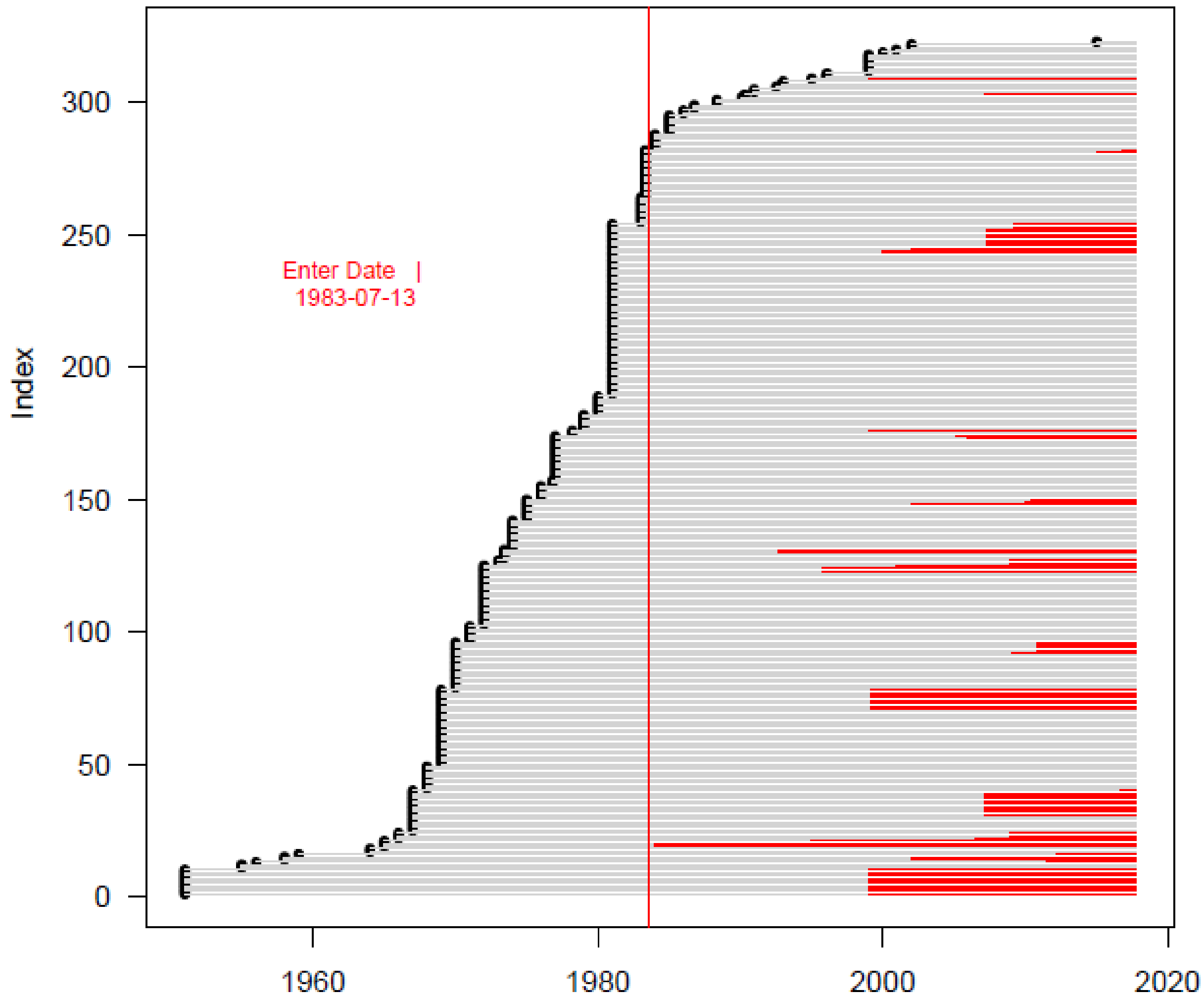

Figure 3-107
Service Eras 13 kV Air Magnetic

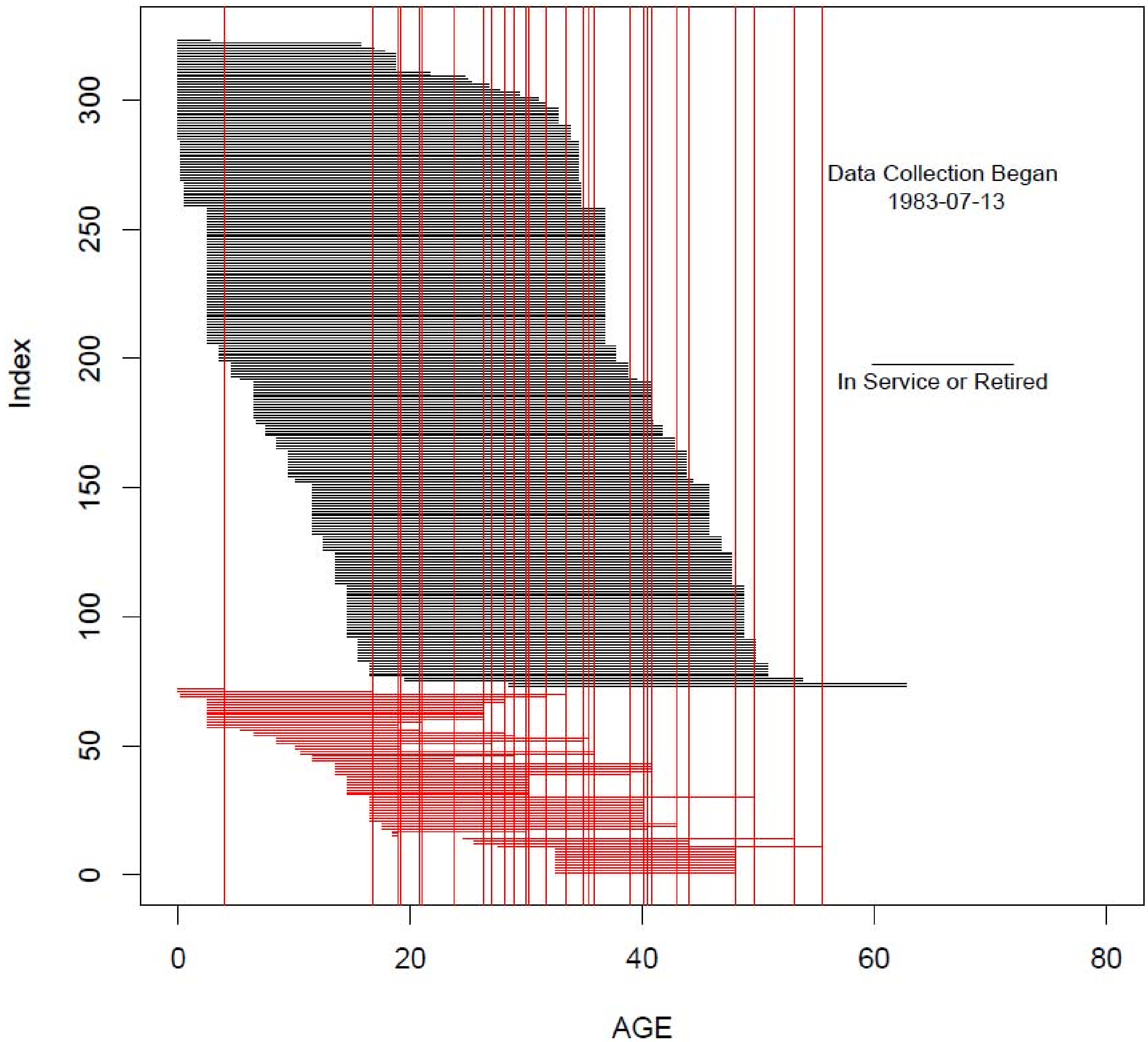

Figure 3-108
Service Ages 13 kV Air Magnetic

Removal Hazard Rate 13 kV Air Magnetic

Figure 3-109 shows the removal rate developed using the in-service and removed from service data provided for the 13 kV Air Magnetic circuit breaker. In the figure, probability of a 30 year old circuit breaker being removed in its next year of life ranges from 0.9% to 11%.

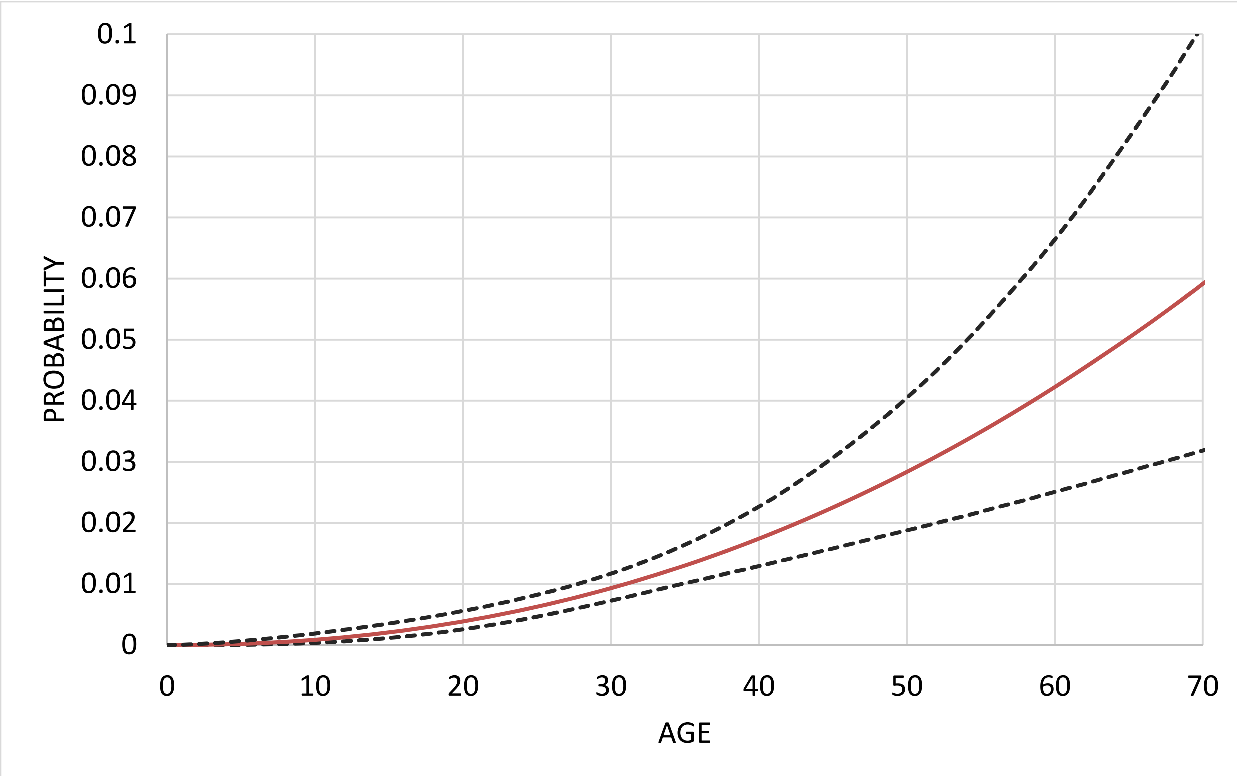

Figure 3-109
Removal Rate 13 kV Air Magnetic

Survival Function 13 kV Air Magnetic

Figure 3-110 shows the survival function developed using the in-service and removed from service data provided for the 13 kV Air Magnetic circuit breaker group. In the figure, the mean probability of a 40 year old circuit breaker surviving (not being removed) in its next year of life ranges from 75% to 84%.

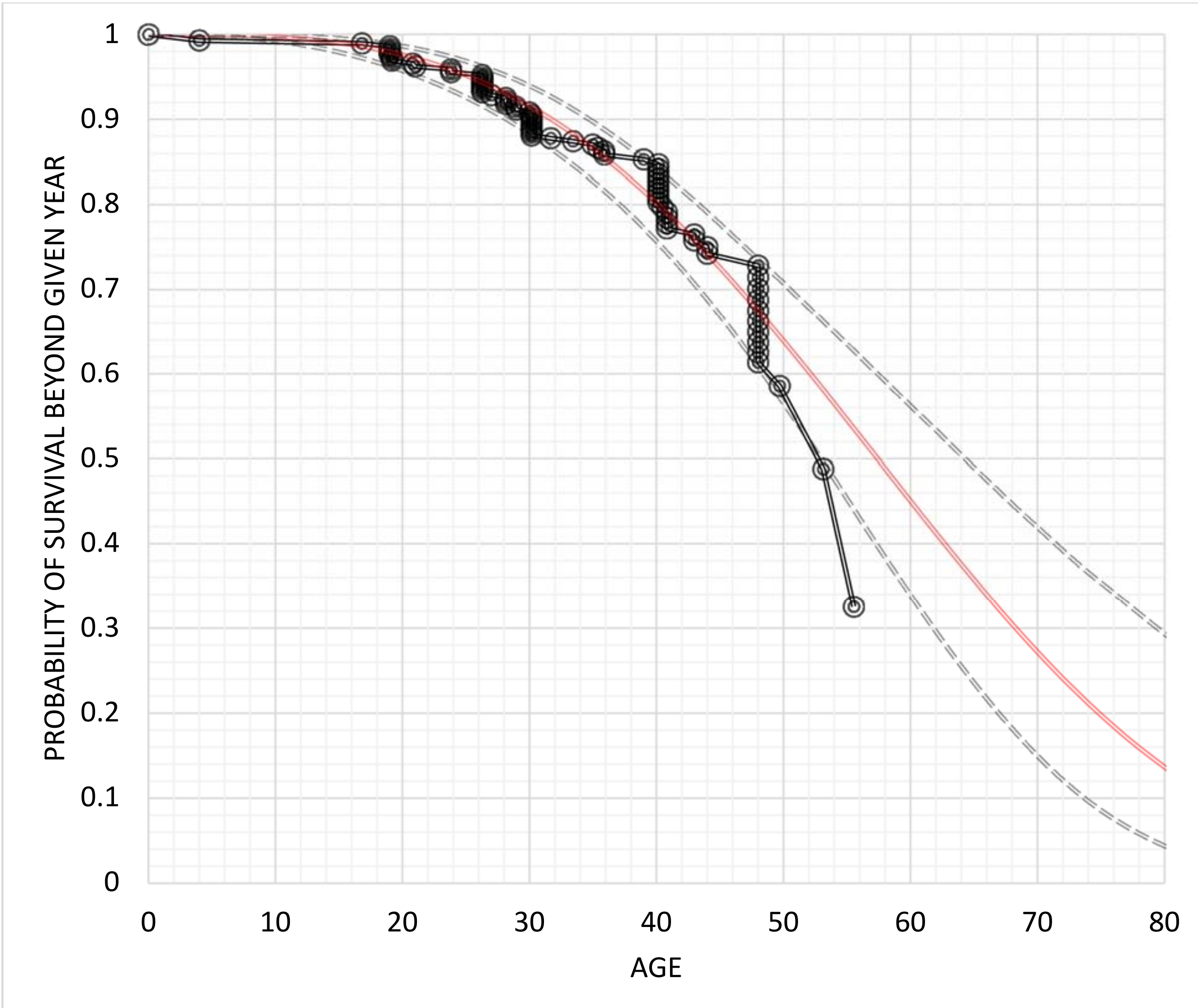

Figure 3-110
Survival Function 13 kV Air Magnetic

Forecasting Removals

Figures 3-111 and 3-112 show the predicted number of circuit breaker removals for each of the next five years. The predicted number of removals for each year are and five year total shown in Figure 3-111. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 10 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 10 or fewer. Figure 3-112 presents the cumulative results combining each year of the five year period.

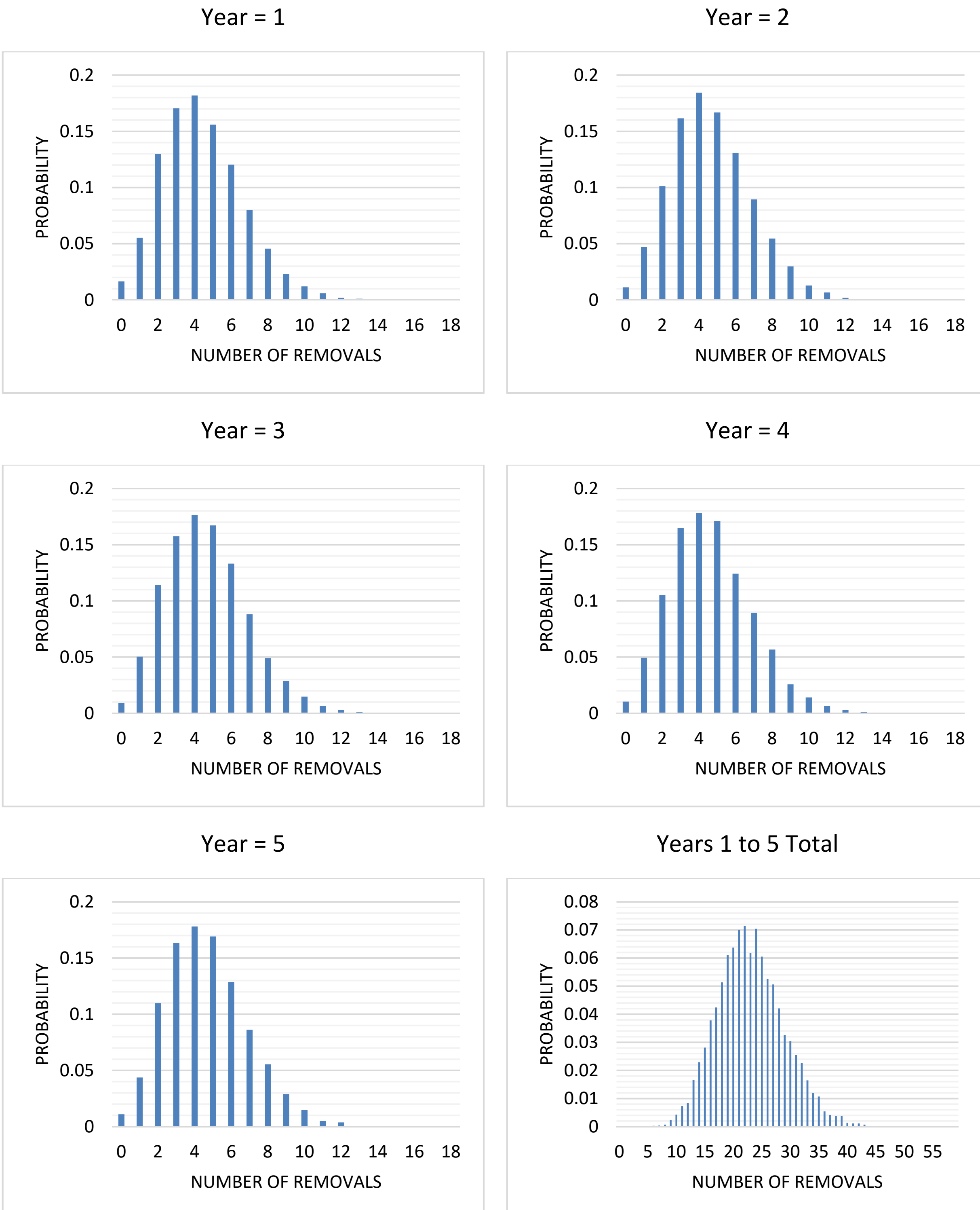

Figure 3-111
Predicted In-Service Circuit breaker Removals for Each of the Next Five Years 13 kV Air Magnetic

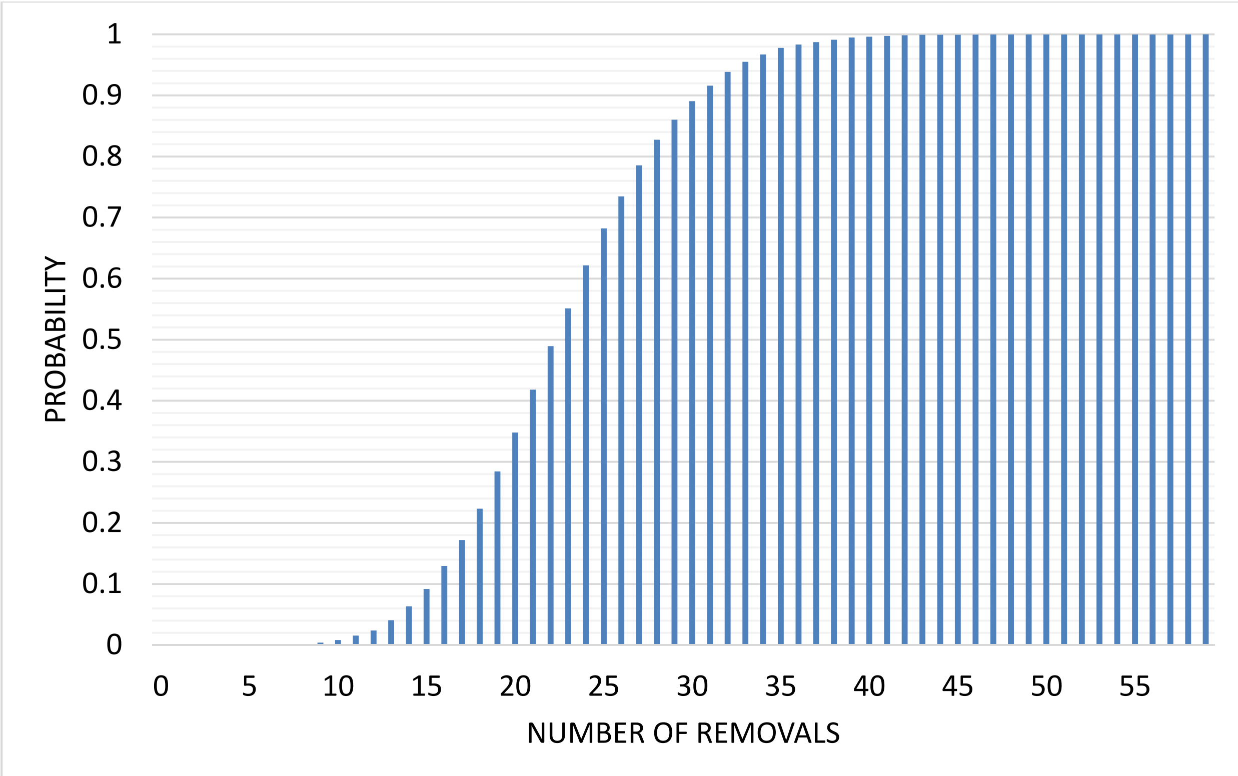

Figure 3-112
Cumulative Probability of In-Service Circuit breaker Removals Next Five Years 13 kV Air Magnetic

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Derivation of Overhead Conductor Hazard Function

Derivation of Overhead Conductor Hazard Function

Technical Update, February 2018

EPRI Project Manager
B. Desai

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Electric Power Research Institute (EPRI)
1300 West W.T. Harris Blvd.
Charlotte, NC28262

Principal Investigators
B. Desai
S. Jiang

Coplanar Consulting, LLC
893 Princess Drive
Yardley, PA 19067

Principal Investigator
M. Lebow

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EXECUTIVE SUMMARY

A key goal of asset management is to base decisions on equipment's fleet mean life expectancy. Insights on the fleet mean life expectancy may be derived from careful analysis of historical condition assessment and replacement data. This report describes EPRI work to develop a replacement hazard rate and apply it to forecast the amount in kilometers of Aluminum Conductor Steel Reinforced (ACSR) overhead transmission conductor expected to require replacement based on past assessments and replacements.

EPRI has developed a methodology using advanced statistical techniques for analyzing conductor historical replacements and assessments and applied it to the Hydro One Networks Inc. overhead ACSR transmission conductor fleet.

Hydro One provided in-service and removed-from-service data for their overhead ACSR transmission conductor fleet. Using this data, EPRI developed a mathematical model relating ACSR conductor age to the probability that an ACSR conductor would be in a condition warranting removal. The model, along with demographic information about the current fleet, was used to project the amount in kilometers of ACSR conductors expected to be in a state warranting removal from service over the next five, ten and twenty-year periods.

Keywords
Overhead Transmission Conductor
Asset Management

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1 INTRODUCTION AND BACKGROUND

Introduction

Hydro One Networks Inc., like many utilities, is striving to maintain the reliability of its transmission network while controlling maintenance, repair and replacement costs. Aging equipment, more stringent operating requirements, financial constraints and retiring expertise have made the management of transmission line assets increasingly challenging.

To address these challenges, Hydro One is reviewing its maintenance and replacement practices to ensure they are underpinned by sound evidence. This includes the use of condition and risked-based maintenance and replacement scheduling using advanced analytics-based techniques. Understanding the condition and remaining life of conductors would help transmission asset managers make better decisions about conductor maintenance, repair, and replacement.

As part of this asset management effort, Hydro One asked EPRI to investigate available Hydro One overhead transmission line conductor demographic and condition data and determine what insights could be obtained to support asset management decisions.

This report describes the EPRI investigation.

Background

Hydro One's service territory is the size of Texas plus California, and driving across it can take three days. Most of the province's population is concentrated along the southeastern border far from hydroelectric generating stations. Long transmission circuits as well as widely distributed substations are required to deliver power over these distances. These transmission and distribution assets are exposed to environmental stresses, including severe weather and temperature variations that can degrade equipment over time.

Hydro One defines Expected Service Life (ESL) as the average age in years that an asset can be expected to operate under normal system conditions. Half of the assets are expected to operate beyond this ESL. Hydro One also defines End of Life (EOL) as the state of having a high likelihood of failure, or loss of an asset's ability to provide the intended functionality as determined through diagnostic data, wherein the failure or loss of functionality would cause unacceptable consequences. EOL is always determined by condition assessment.

One asset of interest, and the focus of this report, is Hydro One's overhead transmission line conductor fleet. Hydro One's estimated ESL for conductors is approximately age 70. Based on past experience, condition assessments are not conducted before 50 years of age. As shown in Figure 1-1, many of the fleet conductor assets are beyond their presently used ESL.

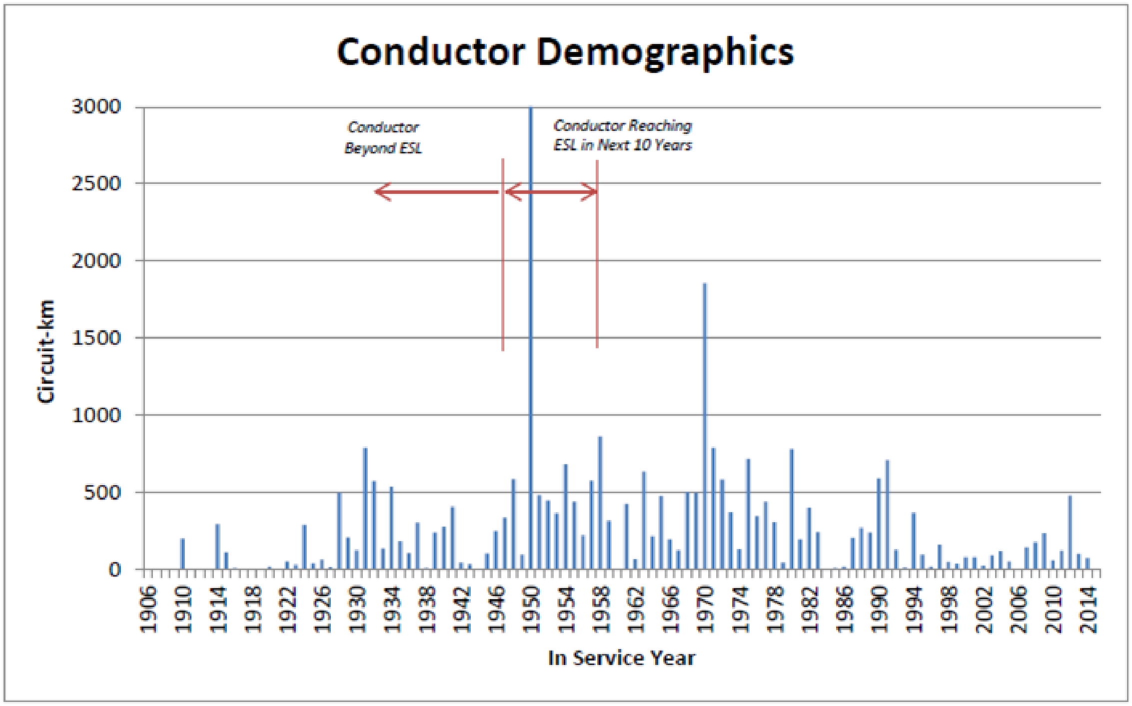


Figure 1-1
Hydro One Conductor Fleet Demographics. 19% of conductors are beyond their expected service life (ESL). In 10 years, 42% will be beyond ESL. (Data source: Hydro One)

Objectives

The project objectives were to investigate data provided by Hydro One Networks Inc. on conductor historical replacements and assessments, along with their in-service overhead transmission conductor fleet, and determine what insights could be obtained to support asset management decisions.

The analysis focused on Aluminum Conductor Steel Reinforced (ACSR) samples. An example is shown in Figure 1-2.

Figure 1-2
Aluminum Conductor Steel Reinforced (ACSR 26/7 Drake)

Approach

The EPRI work plan for this project had the following components:

- Review and gain familiarity with the ACSR conductor condition assessment data provided by Hydro One
- Investigate the feasibility of using the data for conductor life analysis
- Develop a methodology using advanced statistical techniques for analyzing conductor historical replacements and assessments
- Apply the developed methodology to the Hydro One ACSR conductor condition assessment data as well as in-service and removed-from-service data for their overhead ACSR transmission conductor fleet
- Project the amount in kilometers of ACSR overhead transmission conductors expected to be in a state warranting removal from service over the next five, ten and twenty year periods based on the assessment data and the replacements data

Report Organization

The report contains the following chapters:

Chapter 1: Introduction and Background

Chapter 2: Description of the Data

Chapter 3: Exploratory Analyses on Conductor Condition Assessment Data

Chapter 4: Modeling of Assessed Condition as a Function of Age

Chapter 5: Discussion and Applications of Modeling Results

Chapter 6: Conclusions

2
DESCRIPTION OF THE DATA

Introduction

Data Sets

Conductor data was organized into two principal sets:

1) Conductor condition assessment data. This data was provided in two data sets:

    a) The first condition assessment data set (referred to hereafter as data set 1a) was from an earlier study conducted by Hydro One, i.e. Conductor End of Life Study dated August 2016. This set was used to perform exploratory data analyses as documented in Chapter 3.

    b) The second condition assessment data set (referred to hereafter as data set 1b) was provided at a later date and consists of additional OCS 4 data as well as additional samples from "Long Test Reports". This set was used to derive condition assessment based Weibull models as documented in Chapter 4.

2) Replacements and in-service fleet demographic data. The replacement data was used to derive the replacement-based Weibull model as documented in Chapter 4. The in-service fleet demographic data was used as the basis for calculating projections of circuit-kilometers that will reach conditions that require replacements in the future, as documented in Chapter 5.

The remainder of this chapter provides a more detailed description of the above mentioned data sets. Note that the following section on conductor assessment data focuses on data set 1b as this is the data used to derive the condition-based hazard functions.

Conductor Assessment Data

The conductor assessment data set (1b) comprises 443 records extracted from test reports dated from 2001 to 2016, with one assessment performed per conductor. Of the 443 records, 420 records applied to aluminum conductor steel reinforced (ACSR) samples, therefore the analysis focused on ACSR conductors. Other conductor types may perform differently.

The assessment data provided for each conductor included (1) demographic description such as age, size and stranding, and (2) condition assessment including extent of rust, severity of rust, remaining zinc, torsional ductility, and tensile strength. From this data, the project team explored how the conductor overall condition and its constituent assessment factors are affected by independent variables including age, conductor stranding, conductor size, and corrosion zone categorization.

Condition Assessment Methodology

The following describes the parameters considered by Hydro One when performing condition assessment on ACSR conductors. These condition parameters are derived through 3rd party laboratory testing on conductor samples typically five meters in length. These five condition parameters are:

1) Extent of Rust – Visual Inspection
2) Severity of Rust – Visual Inspection
3) Remaining Zinc – ASTM test
4) Torsional Ductility – ASTM test
5) Tensile Strength – ASTM test

Based on the test results, a 1 to 5 (best to worst) condition value was assigned for each test. Strand tests were translated to overall conductor state. Conductor overall condition is expressed as a weighted average, as shown in Table 2-1.

Table 2-1
Overall Conductor Condition: Weighted Average
(Source: *Hydro One Conductor Condition Assessment Program)*

Assessment (Test) Factor	Weight for Overall Condition
Extent of Rust	10%
Severity of Rust	10%
Remaining Zinc	10%
Torsional Ductility	30%
Tensile Strength	40%
Total	100%

Conductor Condition Assessment Data

The Hydro One Conductor Condition Assessment Program defines an overall condition score of 5 as equivalent to “end-of-life.” Hydro One provided condition assessment data collected between January 2001 and December 2016.

Investigators separated conductor assessment data by Overall Condition Score (OCS). Of the initial 404 conductor samples, 28 samples were assessed as OCS 5 from 21 different circuits and 61 samples were assessed as OCS 4 from an additional 29 different circuits. The remaining 315 samples were assessed as OCS 1 through 3.

Hydro One provided an additional set of 16 ACSR condition assessments based on “Long Test Reports” for 12 unique circuits. These were reports of more extensive laboratory investigations of this added set of field samples. All of these samples were considered as OCS 5 providing another 9 different circuits not assessed as OCS 5 in the previous data set.

Considering all the available assessment data, samples from a total of 30 unique circuits were deemed to have an OCS of 5. Figure 2-1 illustrates the circuits that are represented by all three subsets of the conductor assessment data, namely OCS 5, OCS 5 (long), and OCS 4. Note that three circuits are represented by both OCS 5 and OCS 5 (long). Nine circuits are represented by both OCS 5 and OCS 4, and five circuits are represented by both OCS 5 (long) and OCS 4. Among these intersections, three circuits (C27P, D2L) are represented by all three subsets.

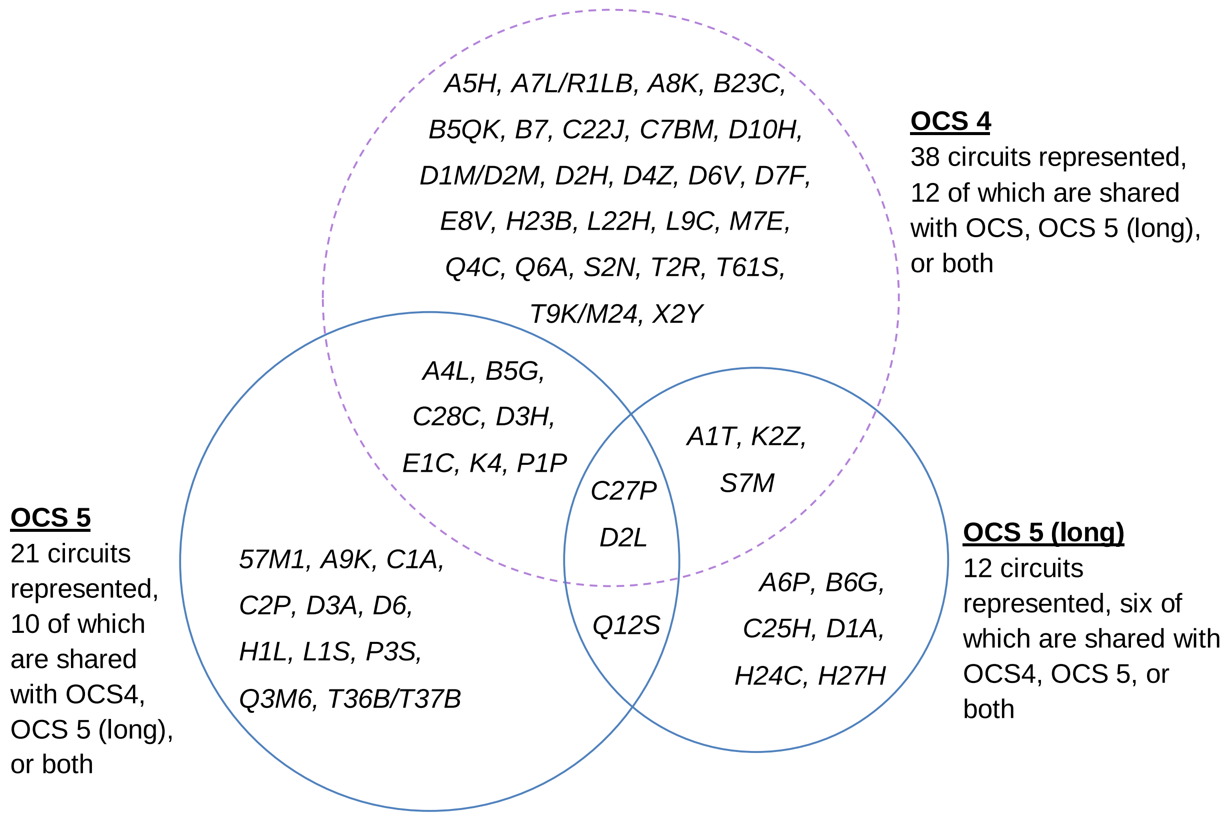


Figure 2-1
Venn Diagram Showing Circuits Associated with All Three Subsets of the Conductor Assessment Data, i.e. OCS 5, OCS 5 (long), and OCS 4, along with their Intersections

Replacements and In-Service Fleet Demographic Data

In addition to the assessment data, Hydro One provided historical replacement records. These replacement records span from January 1988 to January 2017 and the youngest age at replacement recorded was 41. A total of 126 replacement records were provided for 48 unique circuit designations and totaled 3,858 kilometers. Also provided was a list of in-service line sections and their ages representing 559 unique circuit designations. Figure 2-2 shows the cumulative installed conductor length by age, based on in-service ACSR fleet data as of October 2017.

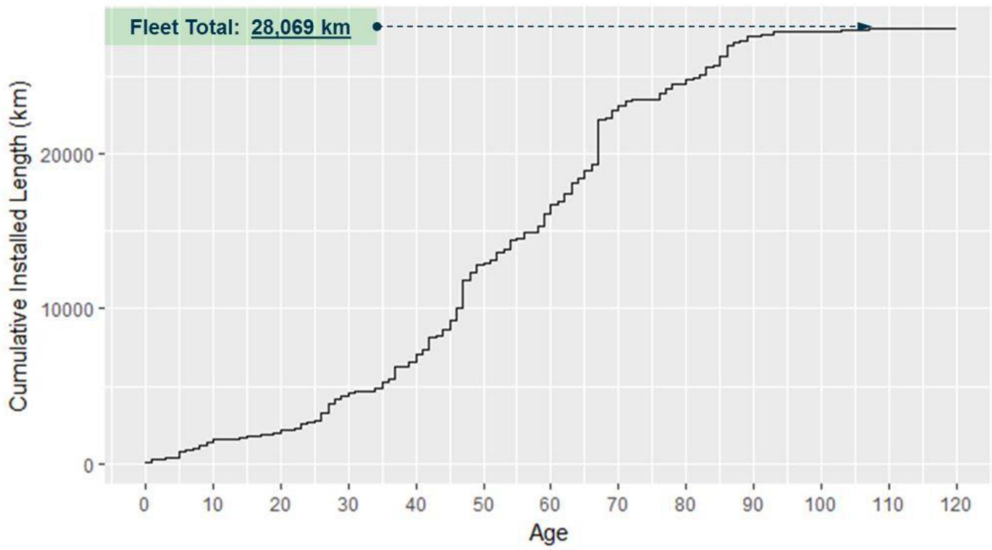


Figure 2-2
Cumulated Installed Length by Age (In-Service Fleet Data as of October 2017)

Figure 2-3 is a bar graph showing the installed length by age, again based on in-service fleet data as of October 2017.

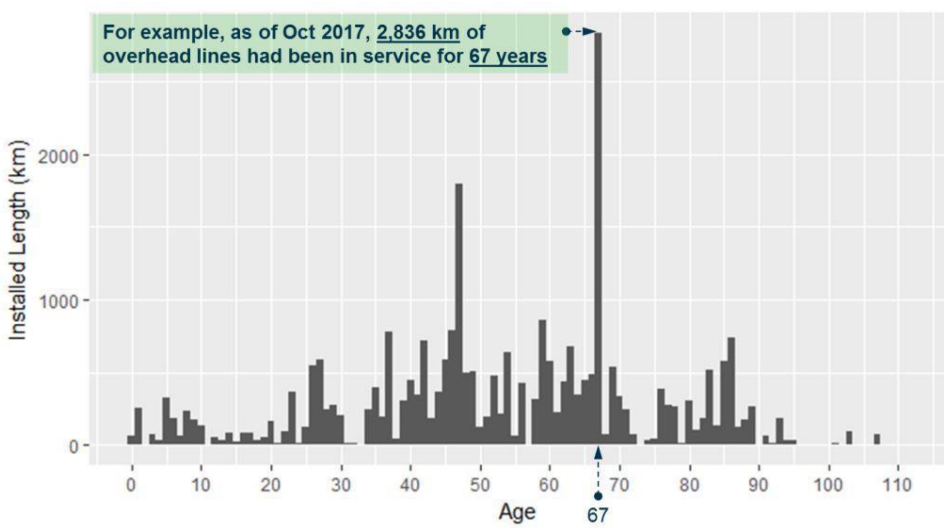


Figure 2-3
Installed Length by Age (In-Service Fleet Data as of October 2017)

Summary of Data Sources

Table 2-2 summarizes the collection periods, number of entries, and number of unique circuits associated with the OCS 5 data set and the replacement records data set.

Table 2-2
Summary of the Assessed OCS 5 Data Set and Replacement Records

Data Source	Collection Period	Number of Entries	Number of Unique Circuits within Data Source
Assessed OCS 5	1/2001 – 12/2016	44	30
Replacement Records	1/1988 – 1/2017	126	48

Figure 2-4 illustrates the circuits that are represented by the OCS 5 data set (including long samples) and replacement records data set. Note that 12 circuits are represented by both the OCS 5 data set and replacement records data set.

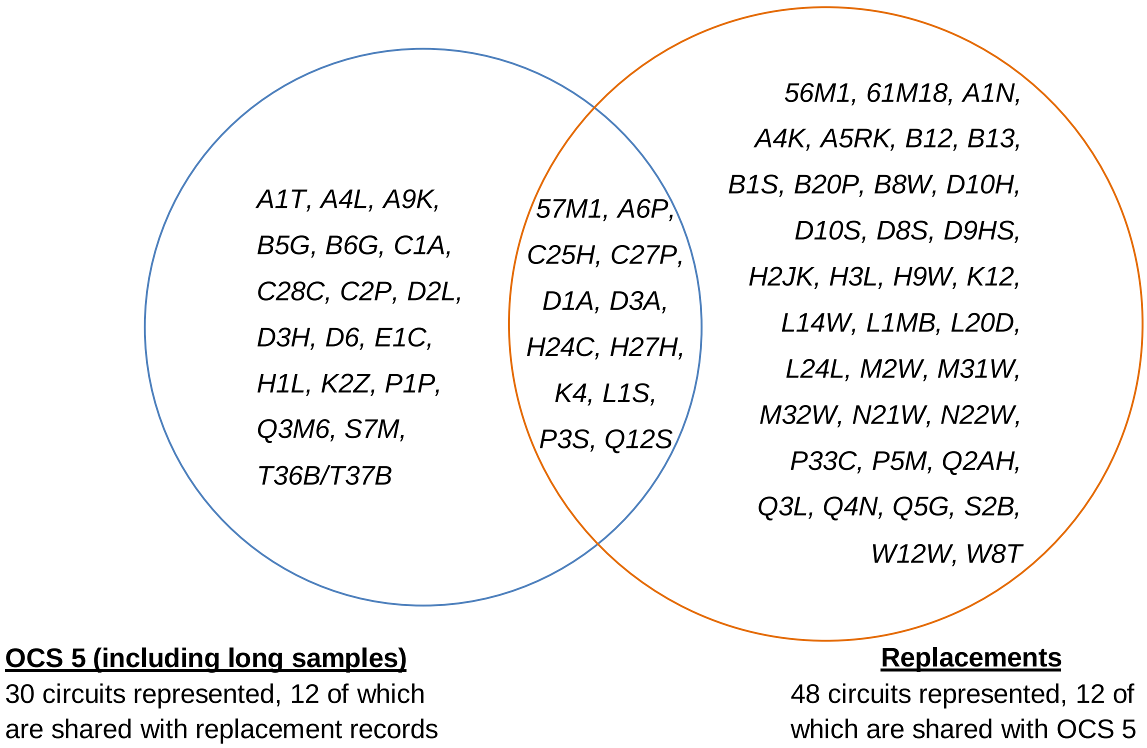


Figure 2-4
Venn Diagram Showing Circuits Associated with the OCS 5 Samples (including Long Samples) and Replacement Records Data Set, along with Their Intersections

3
EXPLORATORY ANALYSES ON CONDUCTOR CONDITION ASSESSMENT DATA

The first step of this effort was to closely examine the provided data (data set 1a) to better understand any useful relationships among the various parameters. Exploratory analyses were carried out on conductor condition assessment data, with a focus on ACSR conductor material types. In conducting these analyses, investigators sought to explore how the overall condition and its constituent conditions (assessment factors) are affected by the following independent variables:

- Age (years)
- Conductor stranding
- Conductor size
- Corrosion zone categorization

Correlation of Overall Condition with Age

The following three figures examine the relationships between overall condition and age; the third slide showing a histogram of conductor count by age between two overall condition groups (1-4 vs. 5). From these figures it may be observed that there is not a simple relationship between age and overall condition.

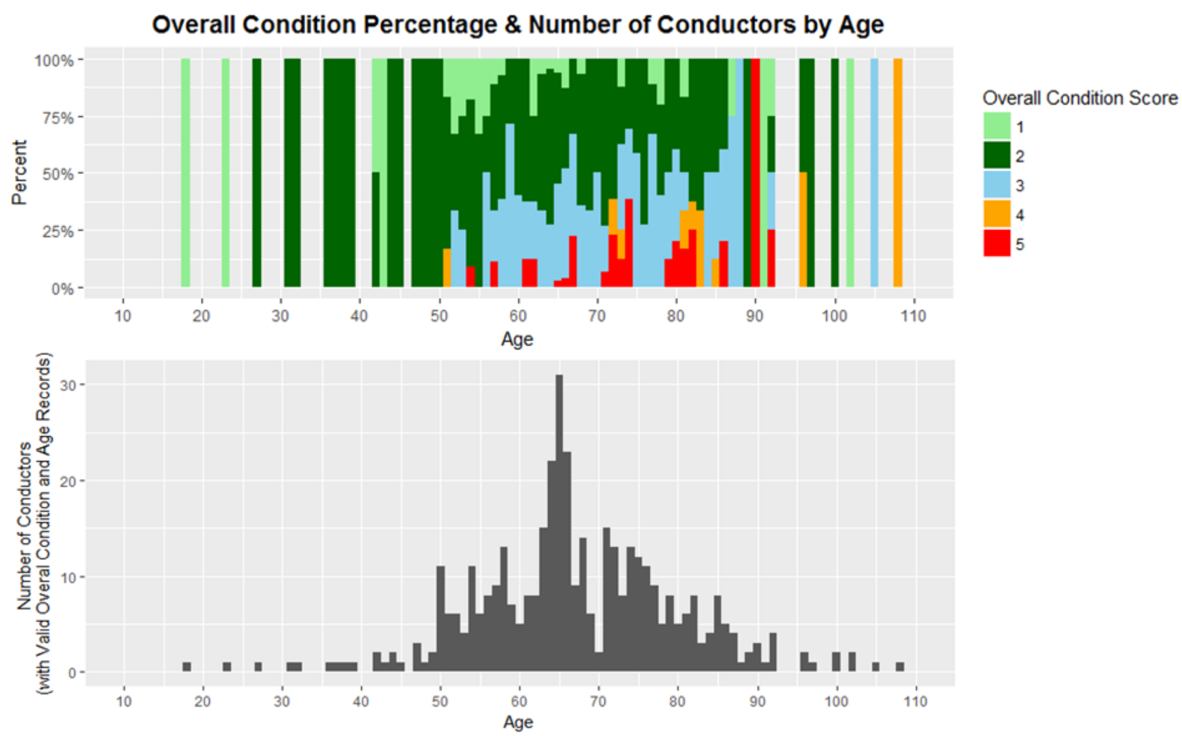


Figure 3-1
Overall Condition Percentage and Conductor Count by Age

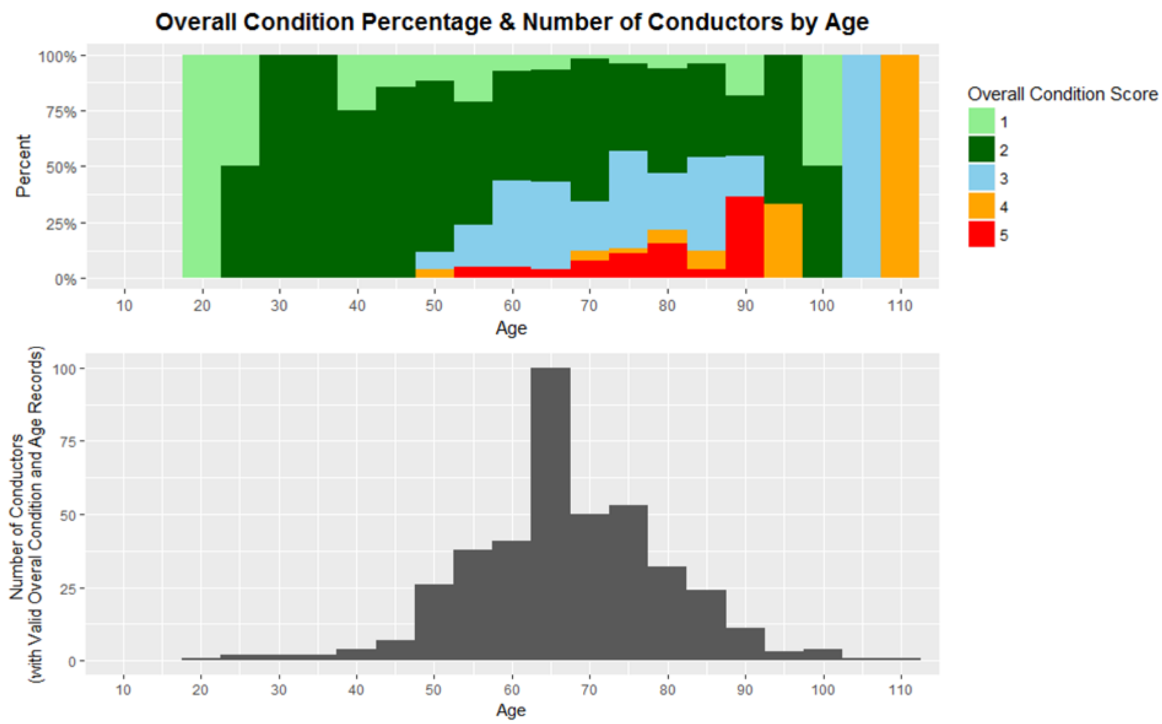


Figure 3-2
Overall Condition Percentage and Conductor Count by Age (5-Year Interval)

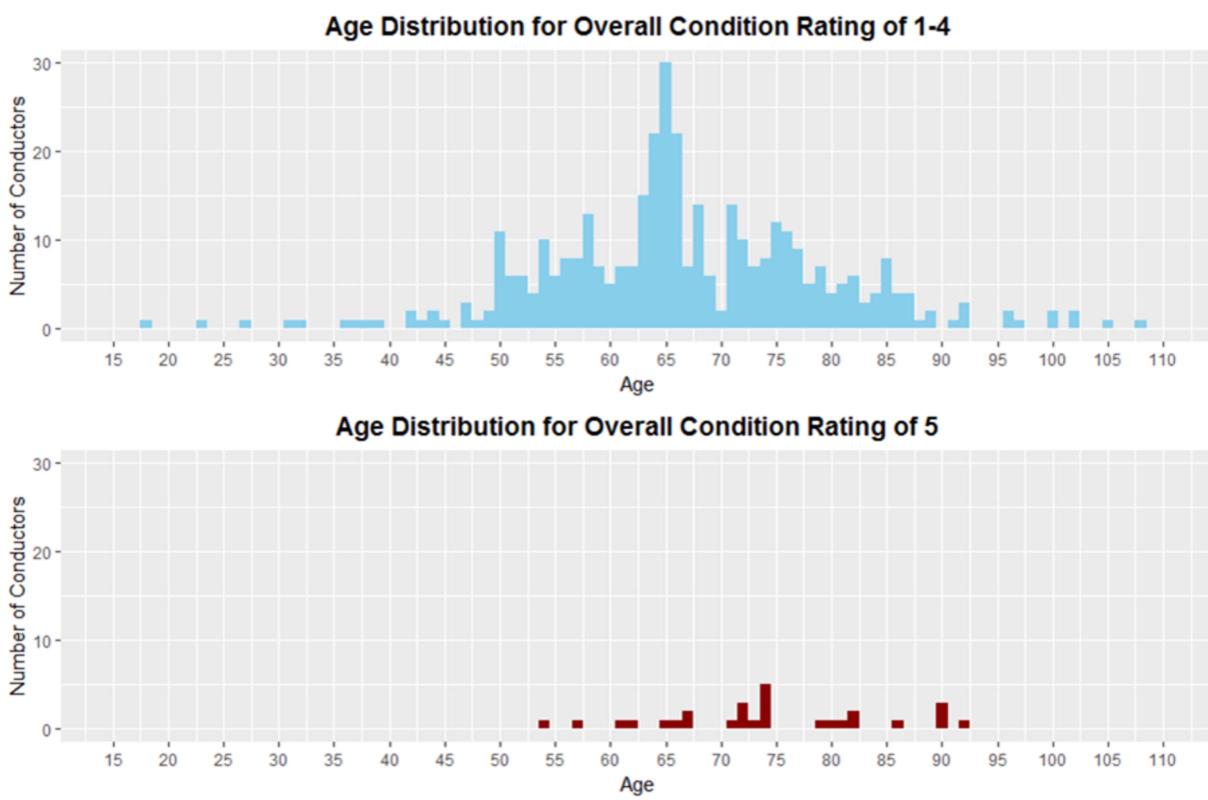


Figure 3-3
Age Distribution by Overall Condition

The analysis proceeded by looking at correlation of constituent conditions with age.

Constituent Conditions (Assessment Factors) by Age

Figure 3-4 through Figure 3-10 show how constituent conditions (assessment factors) correlate with age. The assessment factors include extent and severity of rust, remaining zinc, torsional ductility, and tensile strength.

No clear age-related pattern was observed with any of the constituent condition parameters.

Extent and Severity of Rust

Figure 3-4 shows the extent of rust by age, as determined by visual inspection. Figure 3-5 shows severity of rust by age.

From these two figures it may be observed that rust assessments do not appear to be reliable or useful assessment factors, possibly due to the subjective nature of visual inspection.

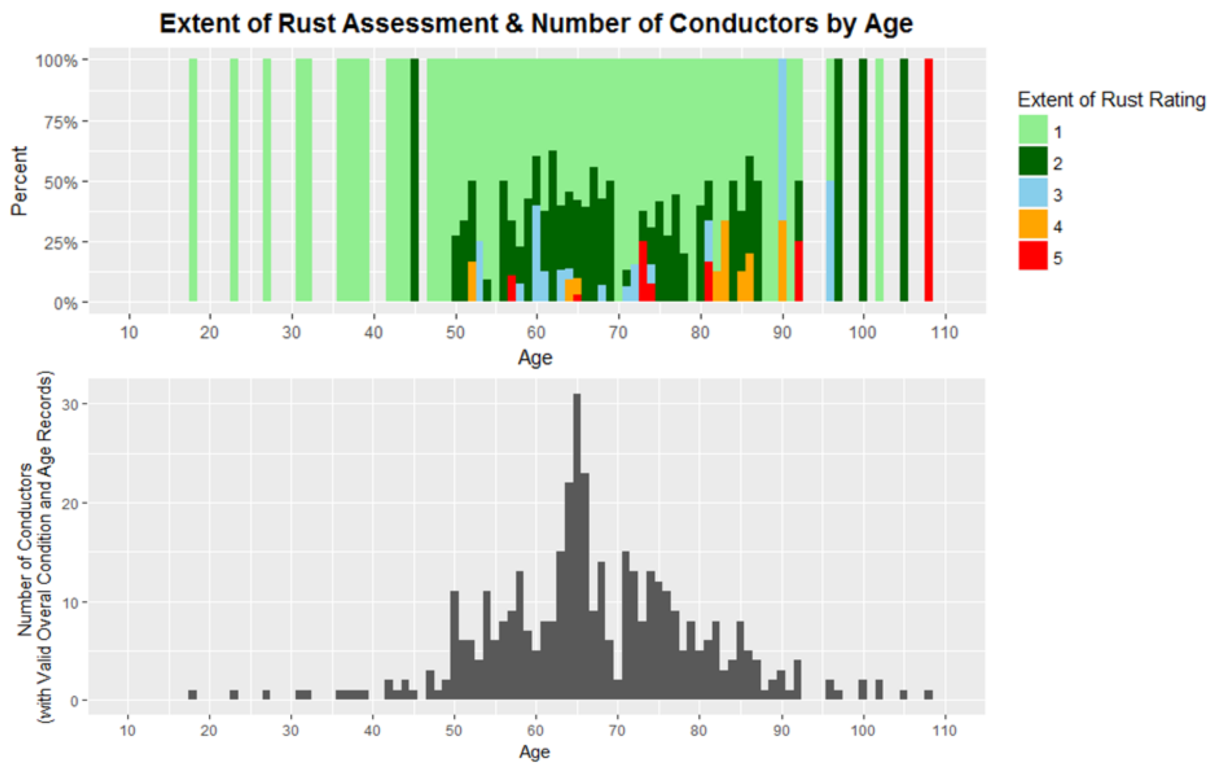


Figure 3-4
Extent of Rust by Age, as Determined by Visual Inspection

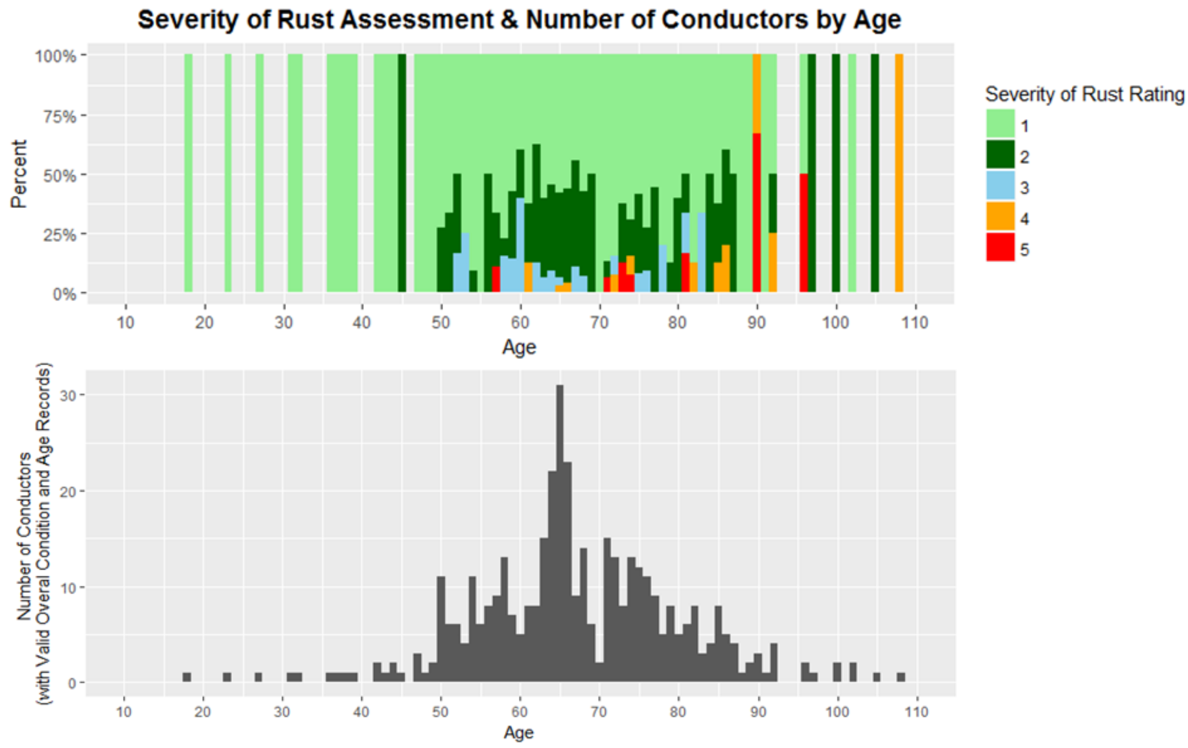


Figure 3-5
Severity of Rust by Age

Figure 3-6 investigates the correlation between severity and extent of rust. Dot size corresponds to the number of samples.

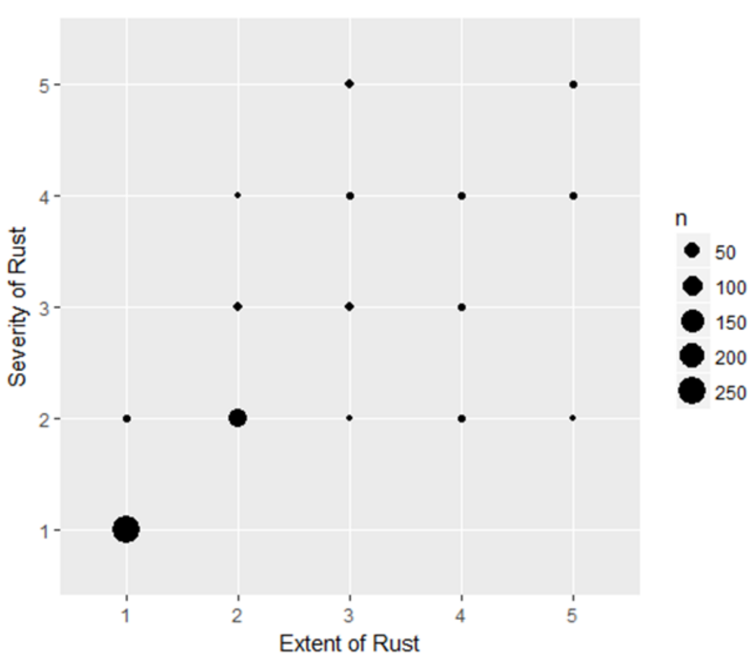


Figure 3-6
Severity vs Extent of Rust

Remaining Zinc

The deterioration of zinc galvanization may be a precursor indicating incipient corrosion of the steel core strands. Figure 3-7 shows remaining zinc by age and the number of conductor samples.

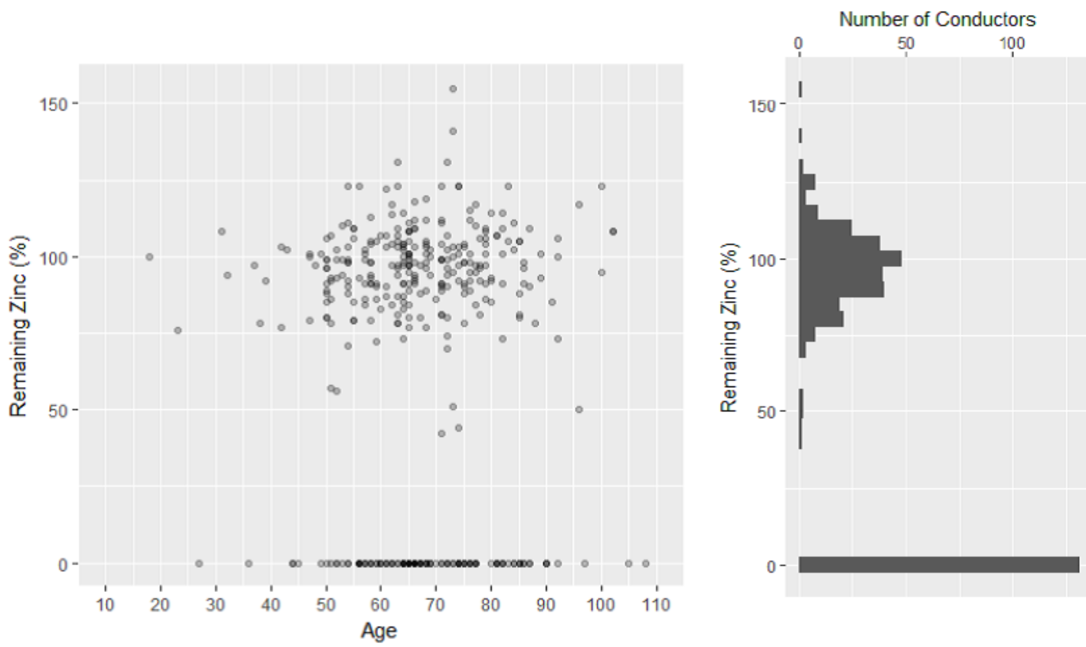


Figure 3-7
Remaining Zinc (%) by Age

Torsional Ductility by Age

Investigators measured torsional ductility of conductor samples per ASTM test specification, using a test rig that twists samples until failure. Results are shown in Figure 3-8.

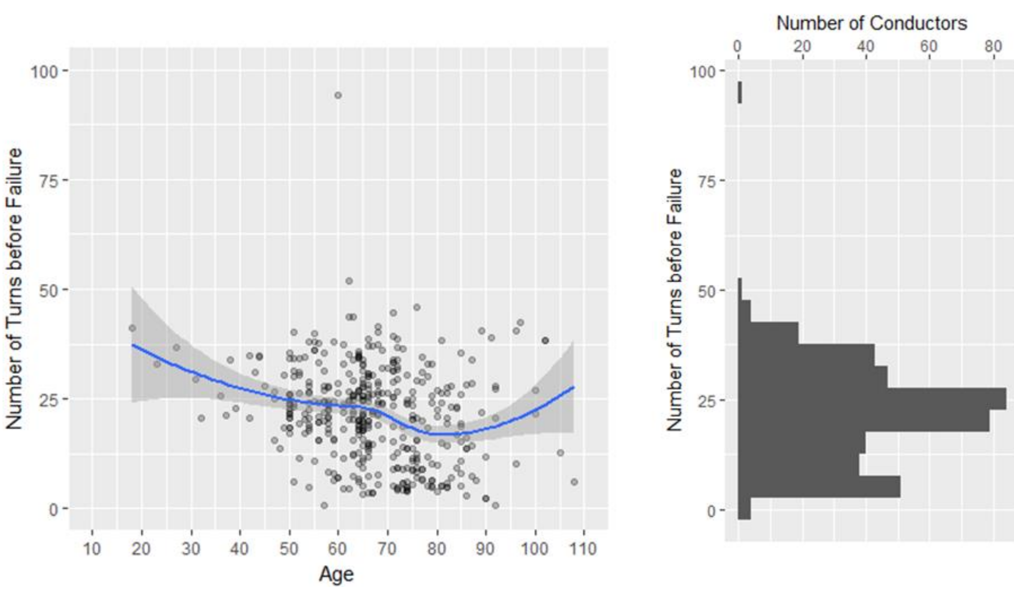


Figure 3-8
Torsional Ductility by Age

Tensile Strength by Age

Testing of tensile strength by age yielded the results shown in Figure 3-9.

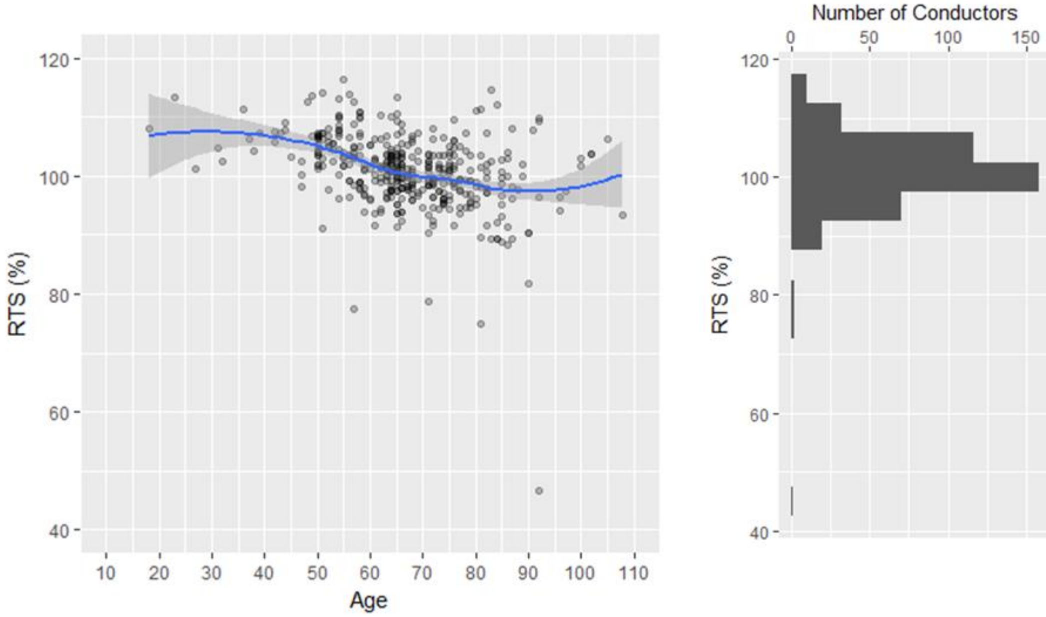


Figure 3-9
Tensile Strength by Age

Rust Assessments vs. Corrosion Zone

Investigators expected to see the best of rust ratings (e.g. 1, 2) skew towards corrosion zone C2 and C3, whereas the worst of the rust ratings (e.g. 5 or even 4) skew towards corrosion zone C5. However, such a pattern is not immediately apparent from the plots in Figure 3-10.

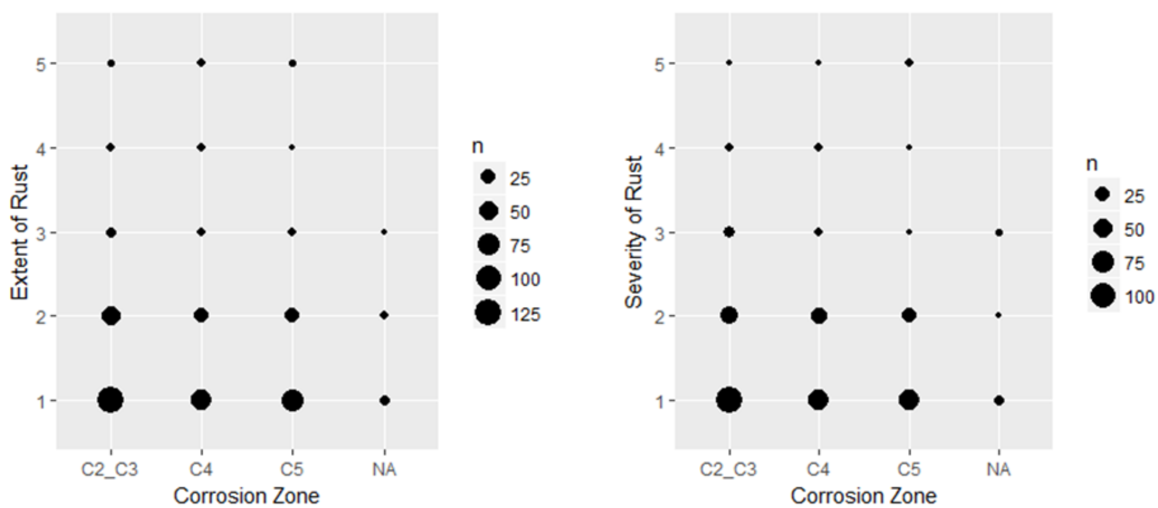


Figure 3-10
Rust Assessments vs. Corrosion Zone

Overall Condition by Conductor Stranding

Conductor stranding refers to the number of aluminum and steel strands comprising the outer layer and the inner core, respectively, of the ACSR conductor. A conductor with the designation 72/7, for example, has 72 outer aluminum strands and 7 inner steel strands. Figure 3-11 investigates any correlation of overall condition with conductor stranding. Figure 3-12 presents box plots illustrating age distributions at each level of stranding. (The boxes represent the middle half of the data; vertical lines represent the median.)

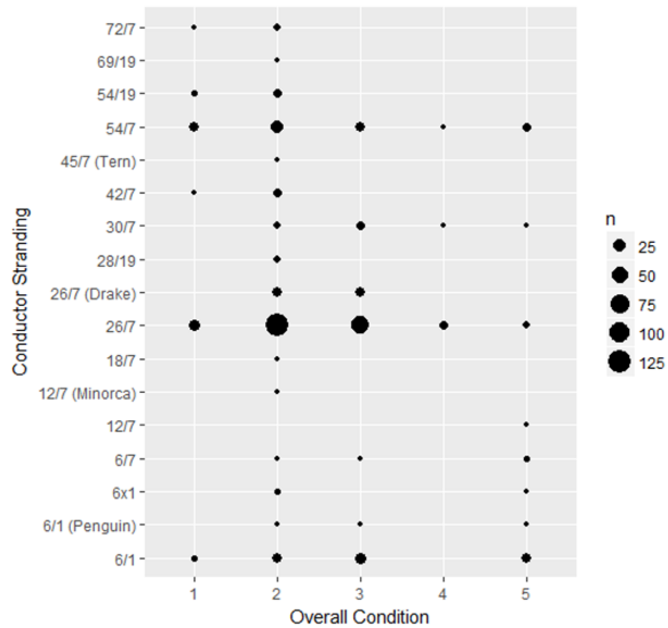


Figure 3-11
Correlation of Overall Condition by Conductor Stranding

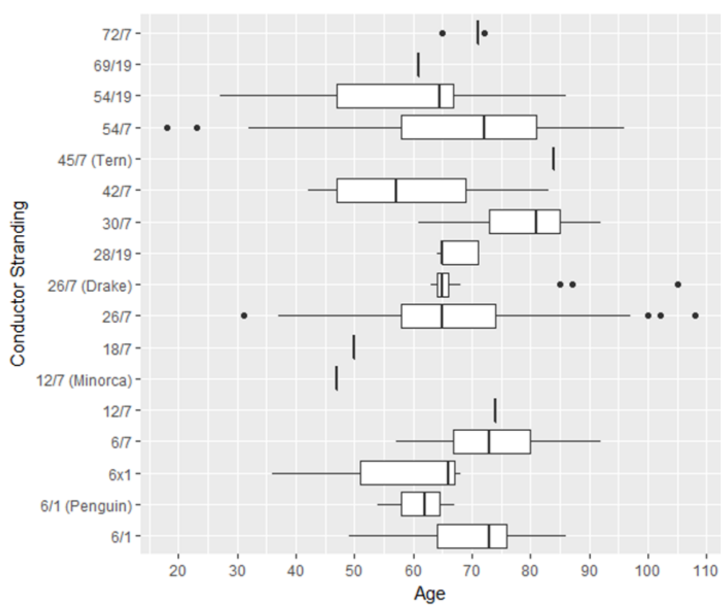


Figure 3-12
Conductor Stranding vs. Age

Overall Condition by Conductor Size

Investigators looked at the relationship between conductor size (based on cross-sectional area) and overall condition. Results are shown in Figure 3-13.

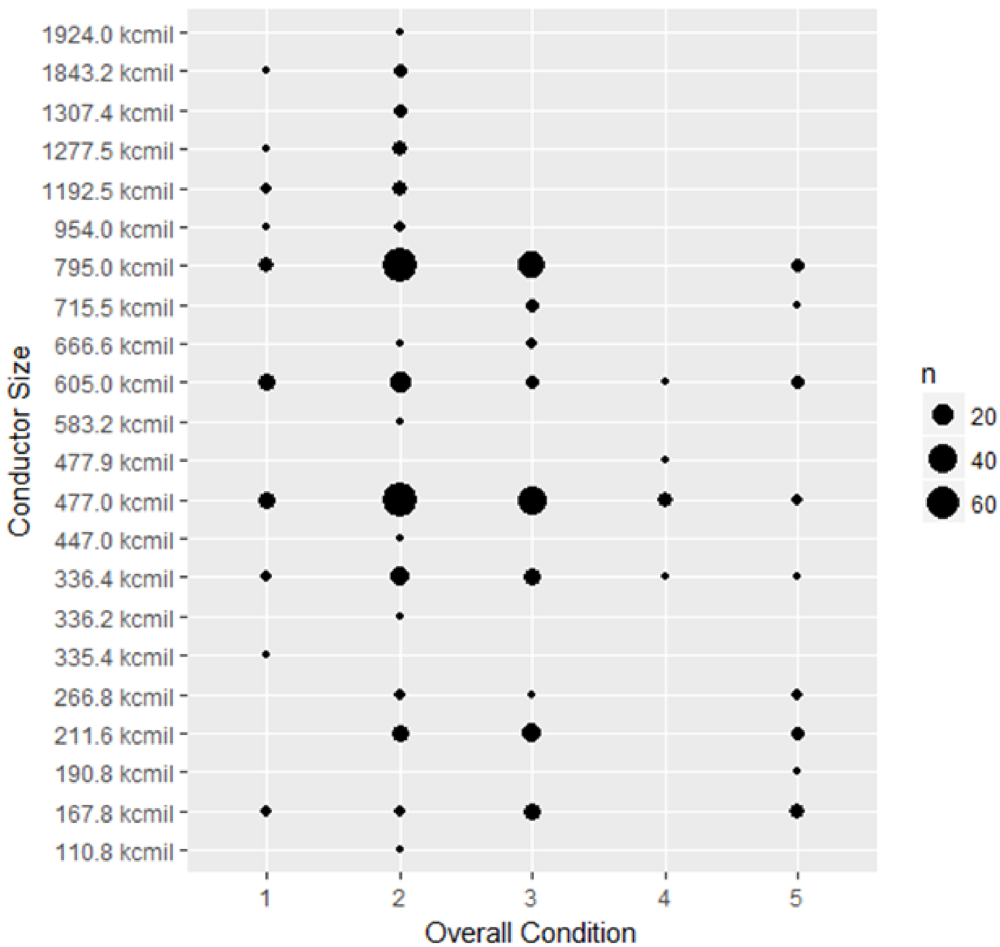


Figure 3-13
Overall Condition by Conductor Size

Conductor Size vs. Age

The project team next examined conductor size versus age. The box plots in Figure 3-14 illustrate age distributions at each conductor size level.

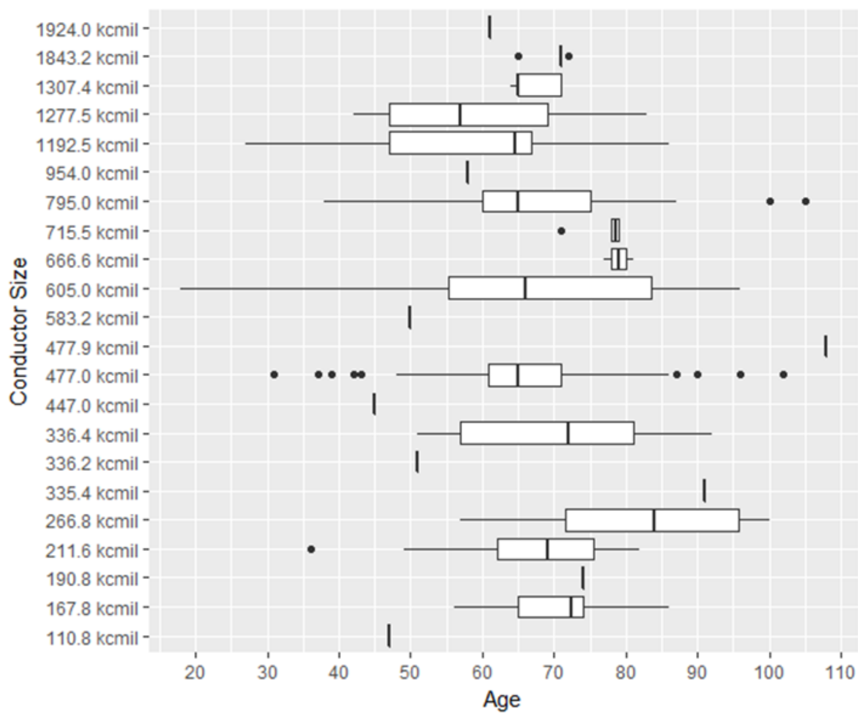


Figure 3-14
Conductor Size vs. Age

Conductor Stranding vs. Size

The exploratory analyses presented so far have focused on all of the ACSR conductor samples. This sample set contains conductors that vary in stranding and size, both of which can possibly be confounding factors that could mask any recognizable influence of age on overall or constituent conditions.

Figure 3-15 investigates any correlation between conductor stranding and size, which directs us to focus on the three smaller ACSR subsets (highlighted), namely 26/7 Drake, 26/7 Non-Drake, and 54/7. Each of these subsets is homogeneous in terms of stranding or size with a sample size larger than any remaining subsets.

Figures 3-16 through 3-42 show some analyses performed on each of these subsets with the objective of removing stranding or size as a possibly confounding factor.

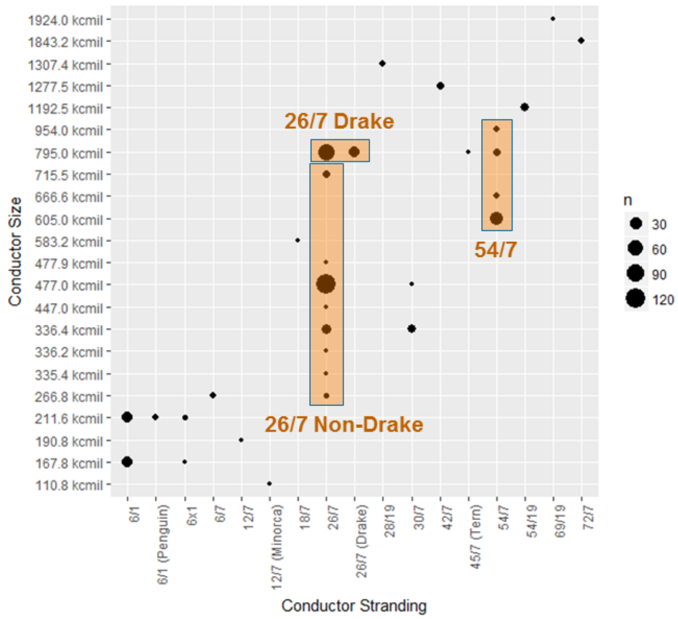


Figure 3-15
Conductor Stranding vs. Size: 26/7 Drake and non-Drake; 54/7

Overall Condition by Age (26/7 Drake)

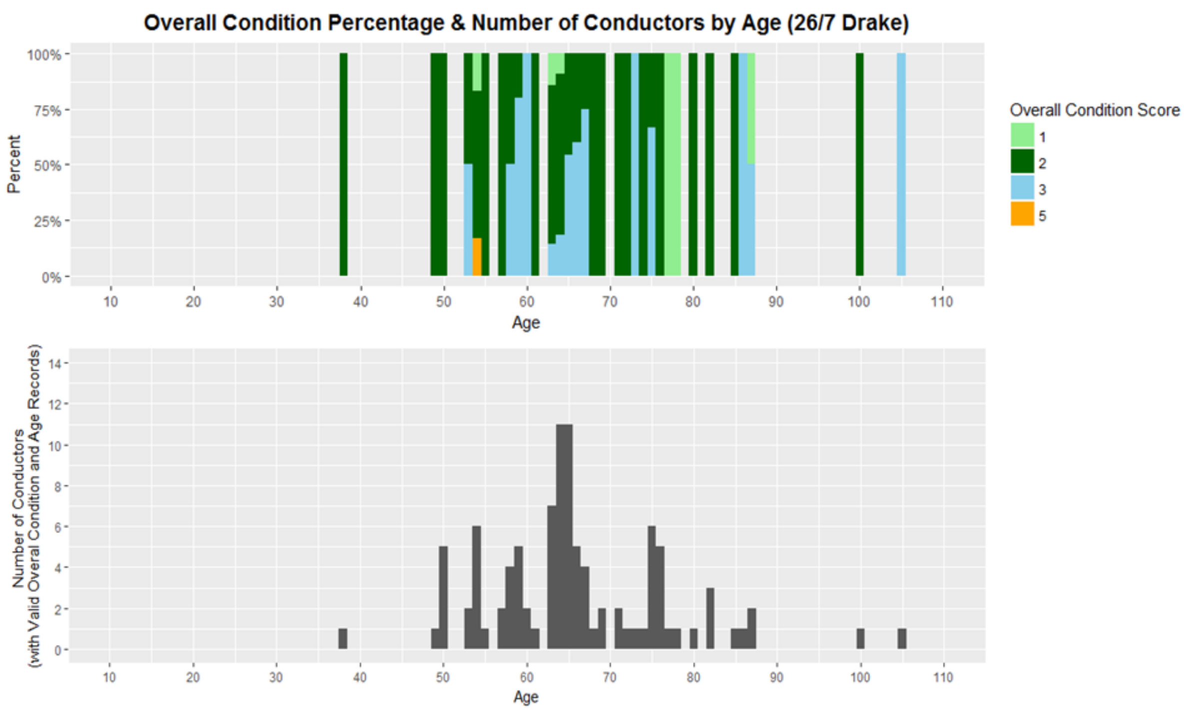


Figure 3-16
Overall Condition by Age (26/7 Drake)

Overall Condition by Age (26/7 Non-Drake)

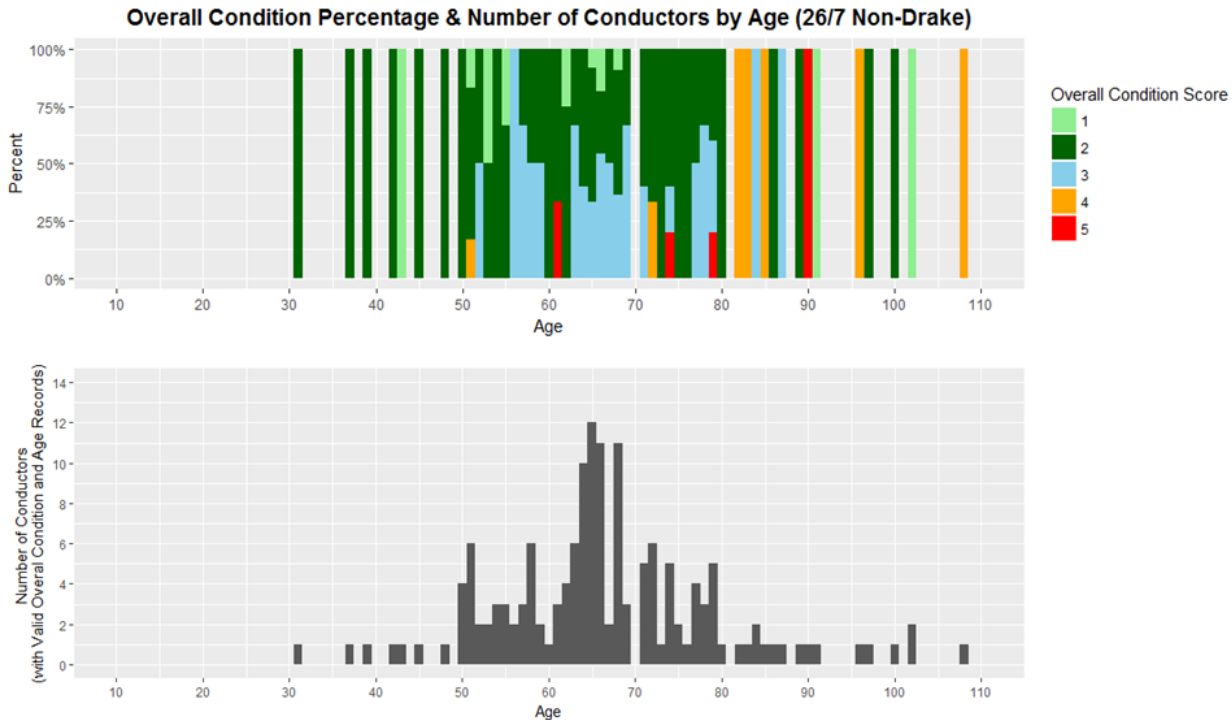


Figure 3-17
Overall Condition by Age (26/7 Non-Drake)

Overall Condition by Age (54/7)

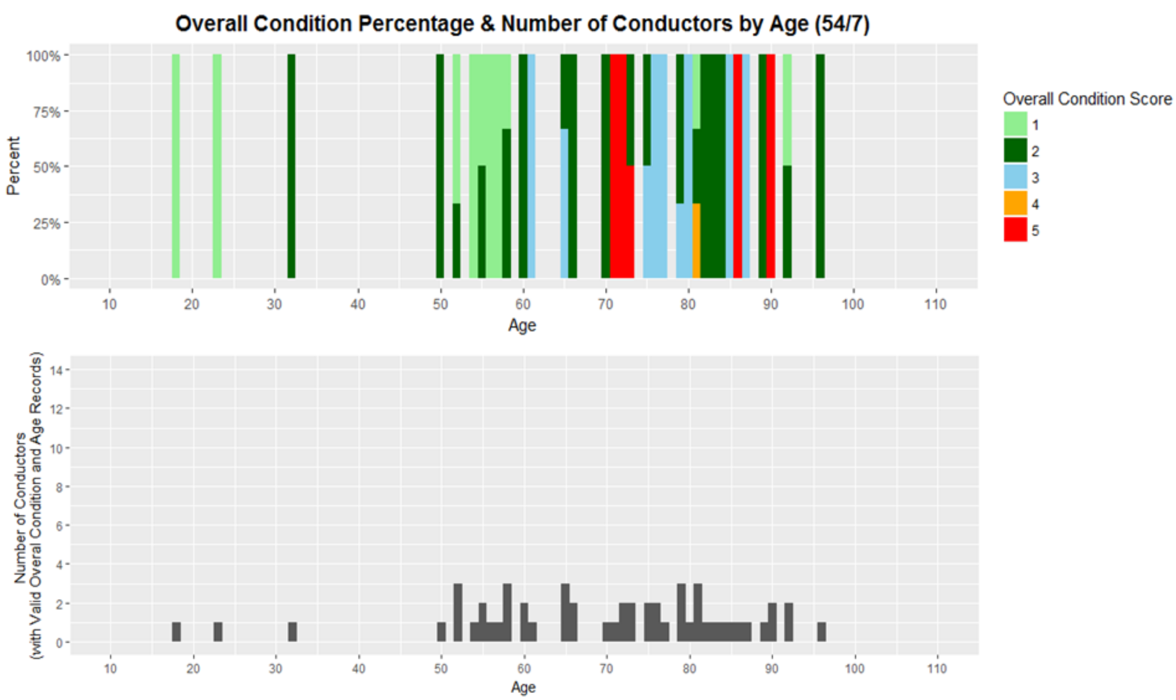


Figure 3-18
Overall Condition by Age (54/7)

Overall Condition by Age Grouping (26/7 Drake)

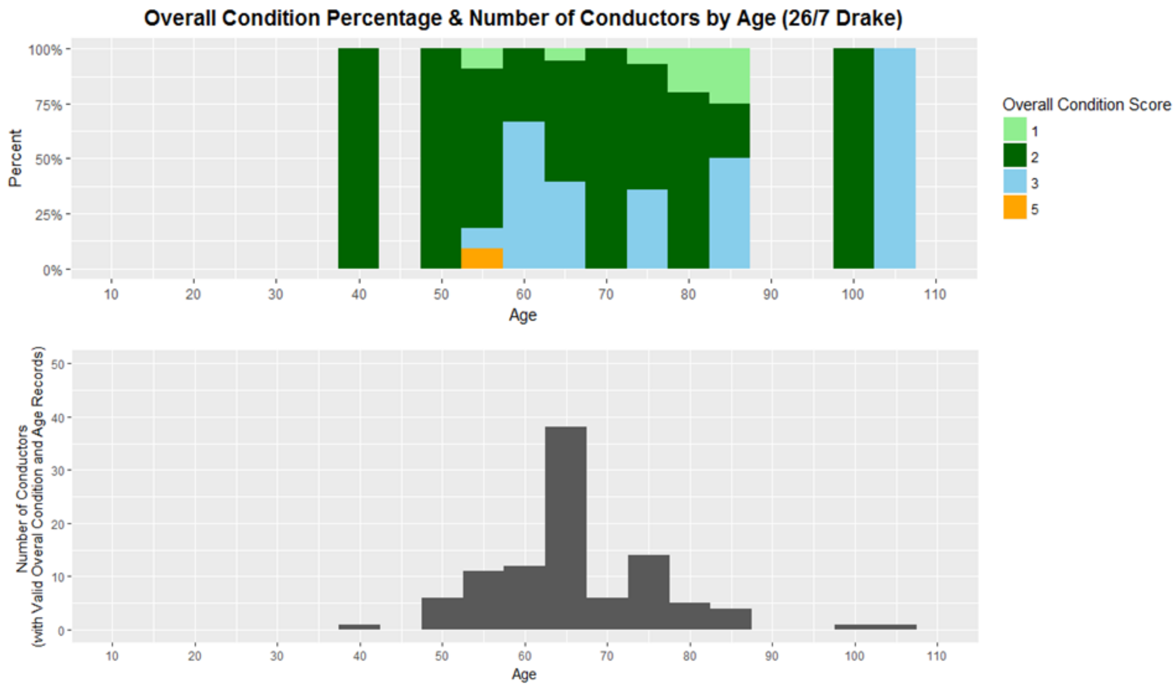


Figure 3-19
Overall Condition by Age Grouping (26/7 Drake)

Overall Condition by Age Grouping (26/7 Non-Drake)

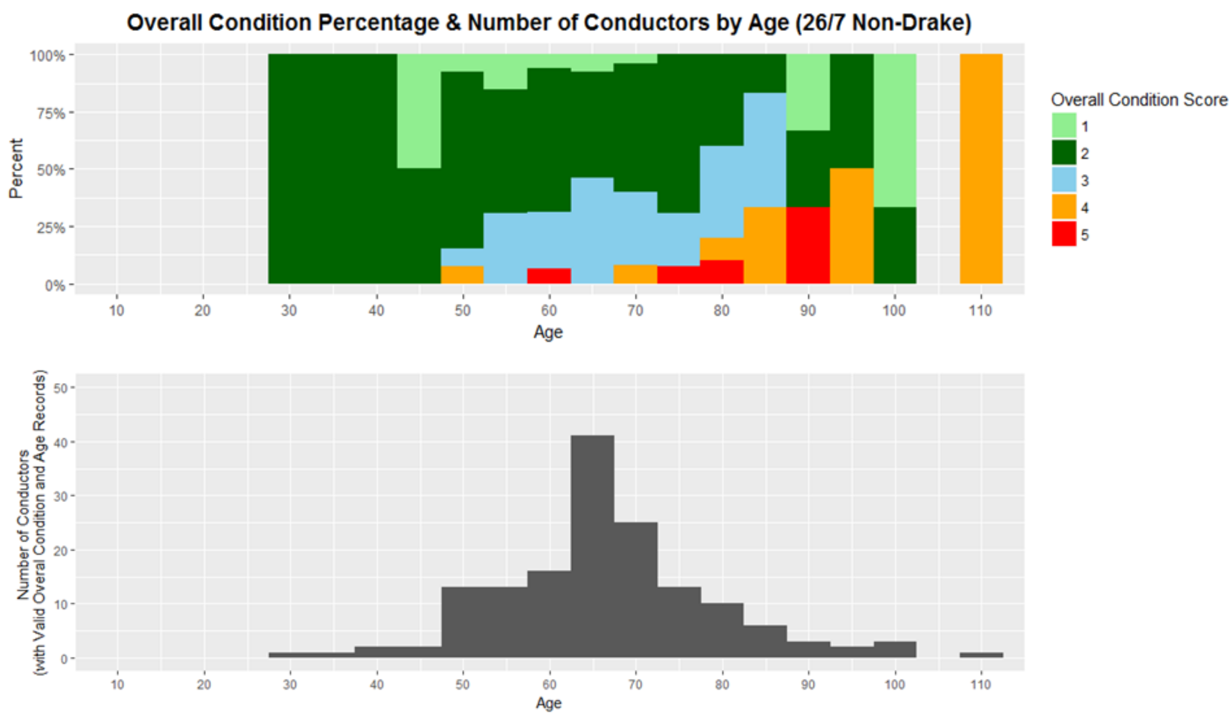


Figure 3-20
Overall Condition by Age Grouping (26/7 Non-Drake)

Overall Condition by Age Grouping (54/7)

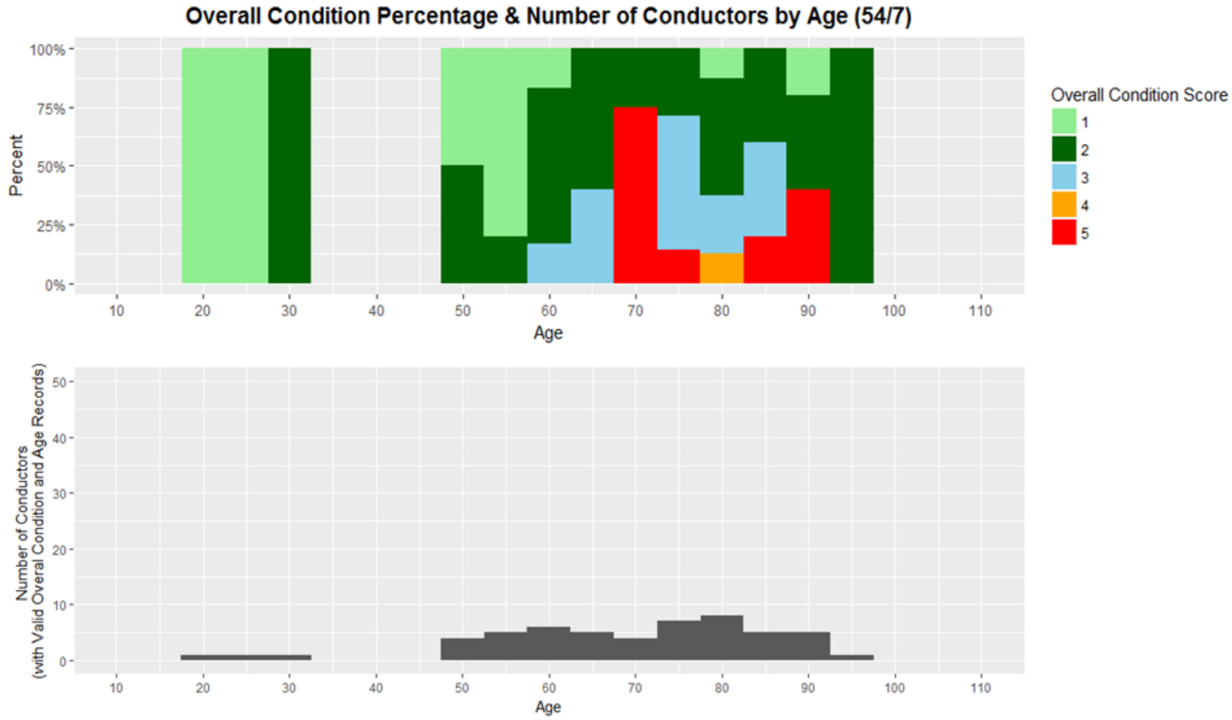


Figure 3-21
Overall Condition by Age Grouping (54/7)

Age Distribution by Overall Condition (26/7 Drake)

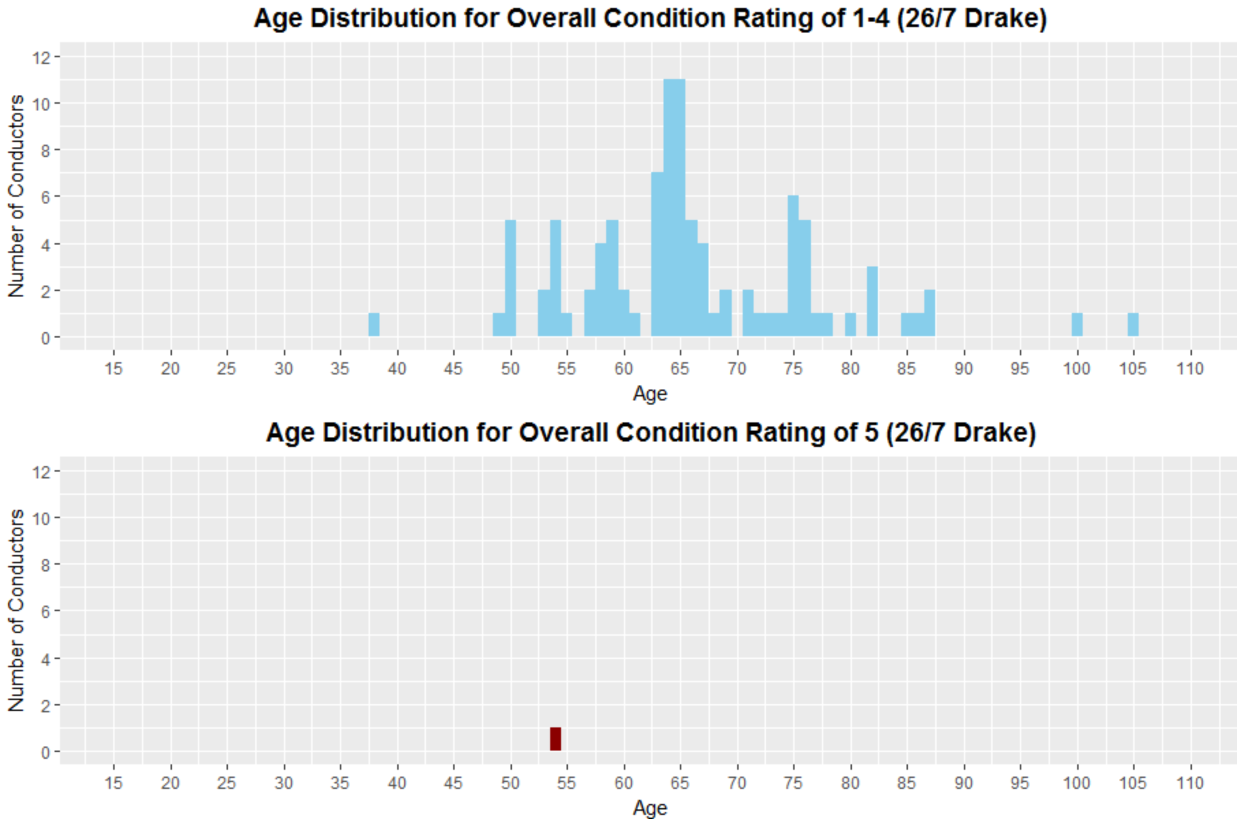


Figure 3-22
Age Distribution by Overall Condition (26/7 Drake)

Age Distribution by Overall Condition (26/7 Non-Drake)

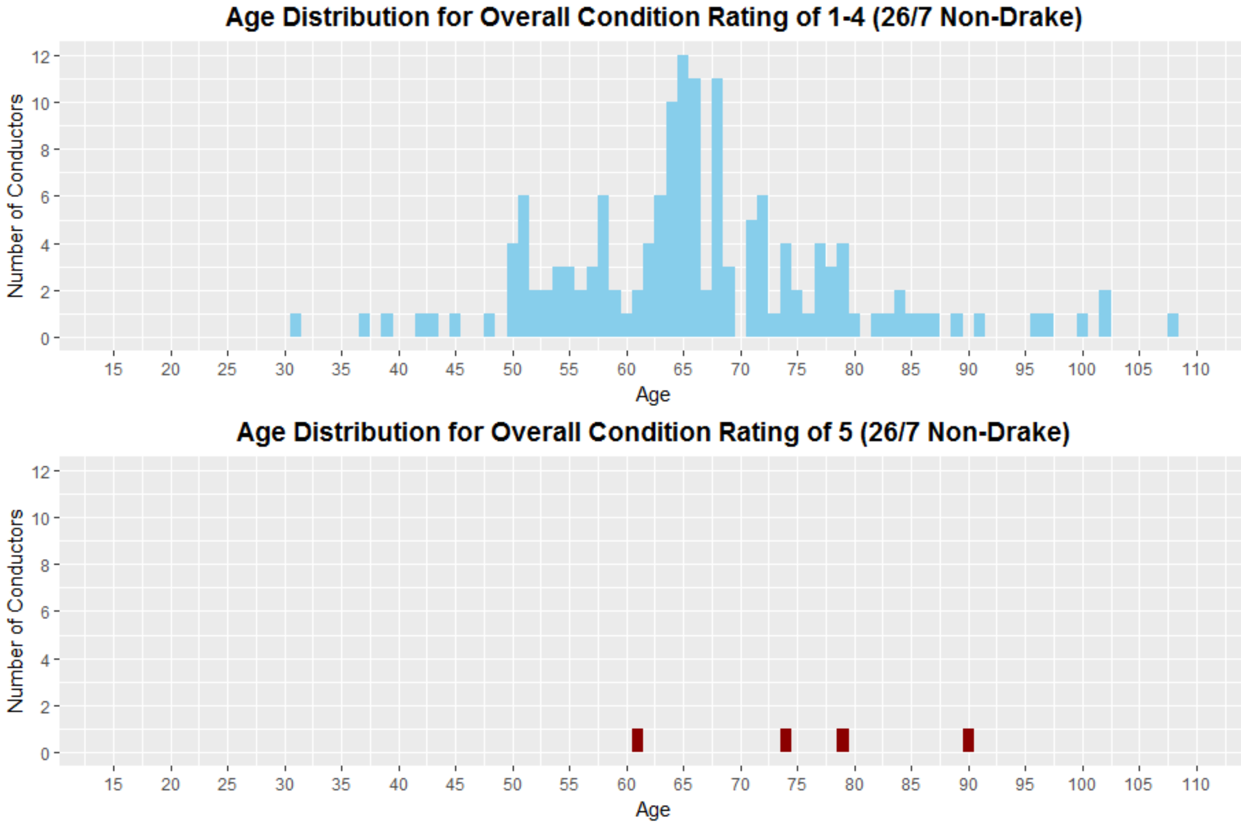


Figure 3-23
Age Distribution by Overall Condition (26/7 Non-Drake)

Age Distribution by Overall Condition (54/7)

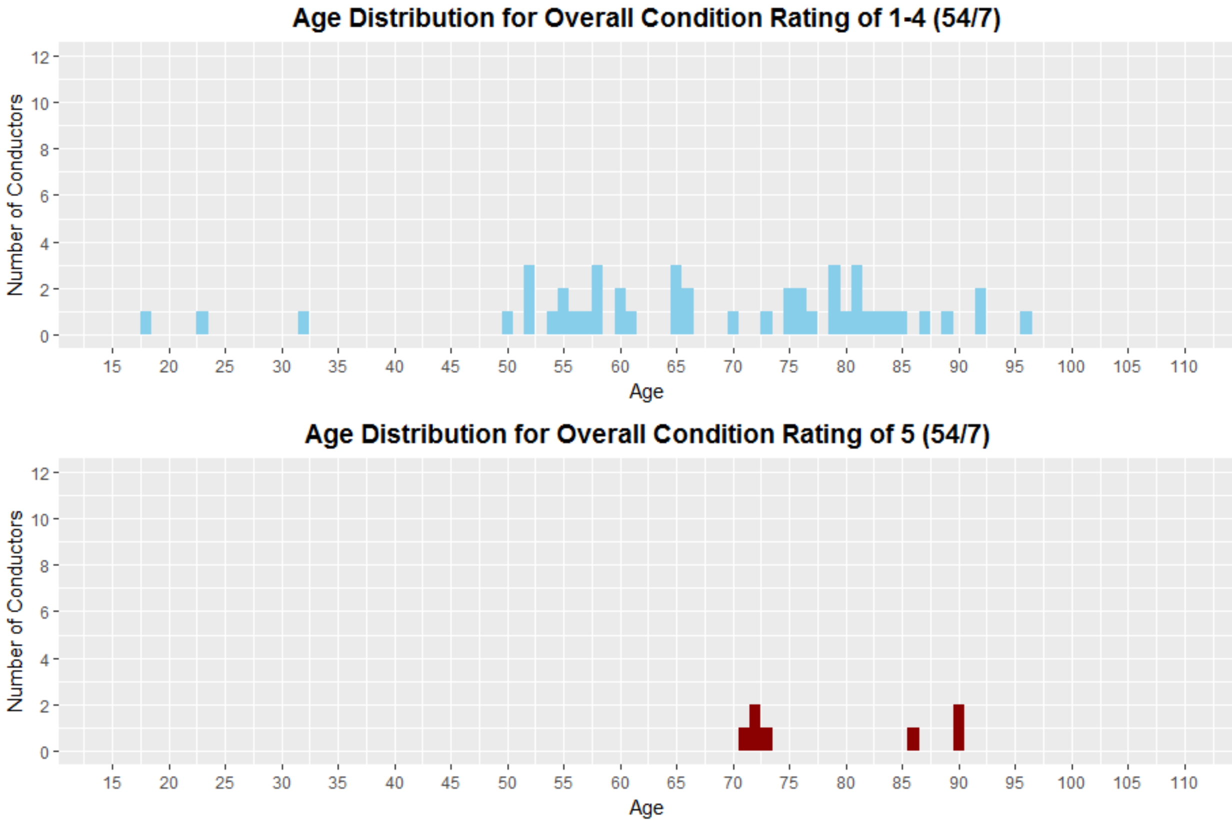


Figure 3-24
Age Distribution by Overall Condition (54/7)

Extent of Rust by Age (26/7 Drake)

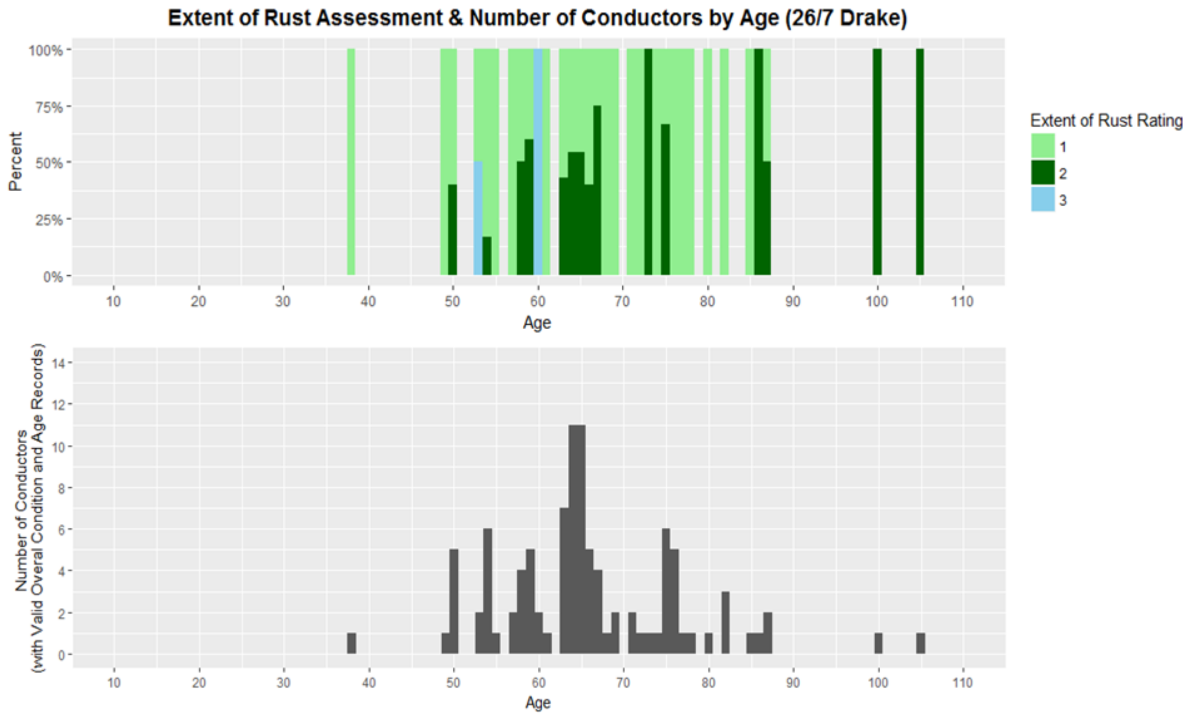


Figure 3-25
Extent of Rust by Age (26/7 Drake)

Extent of Rust by Age (26/7 Non-Drake)

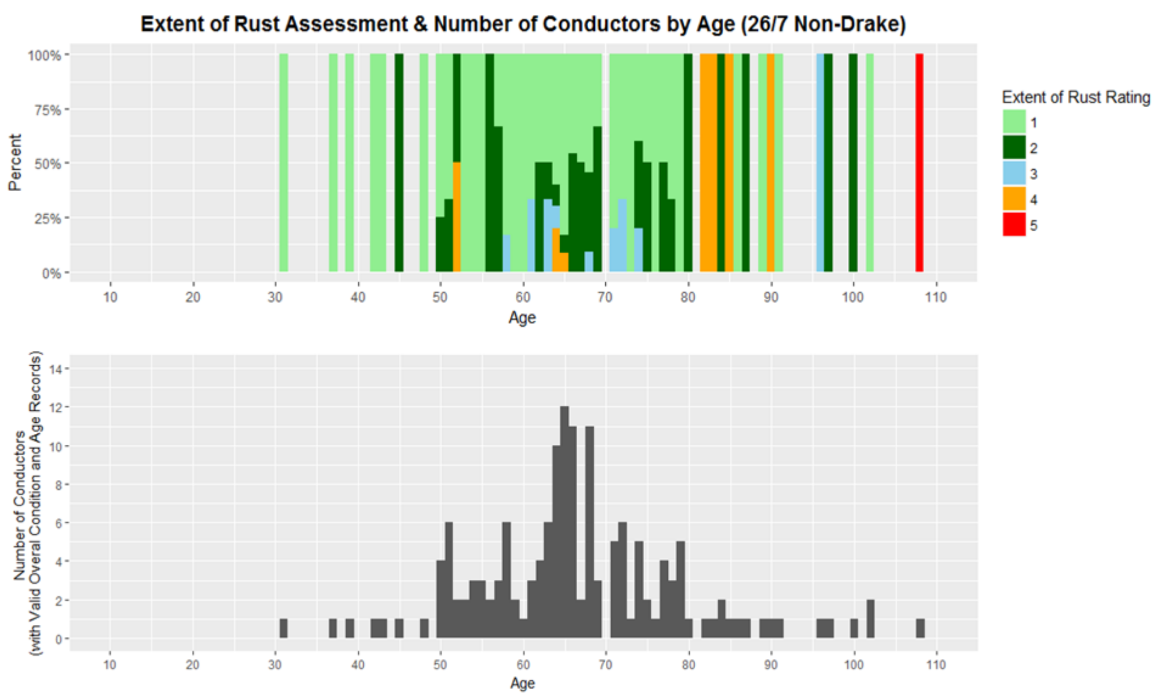


Figure 3-26
Extent of Rust by Age (26/7 Non-Drake)

Extent of Rust by Age (54/7)

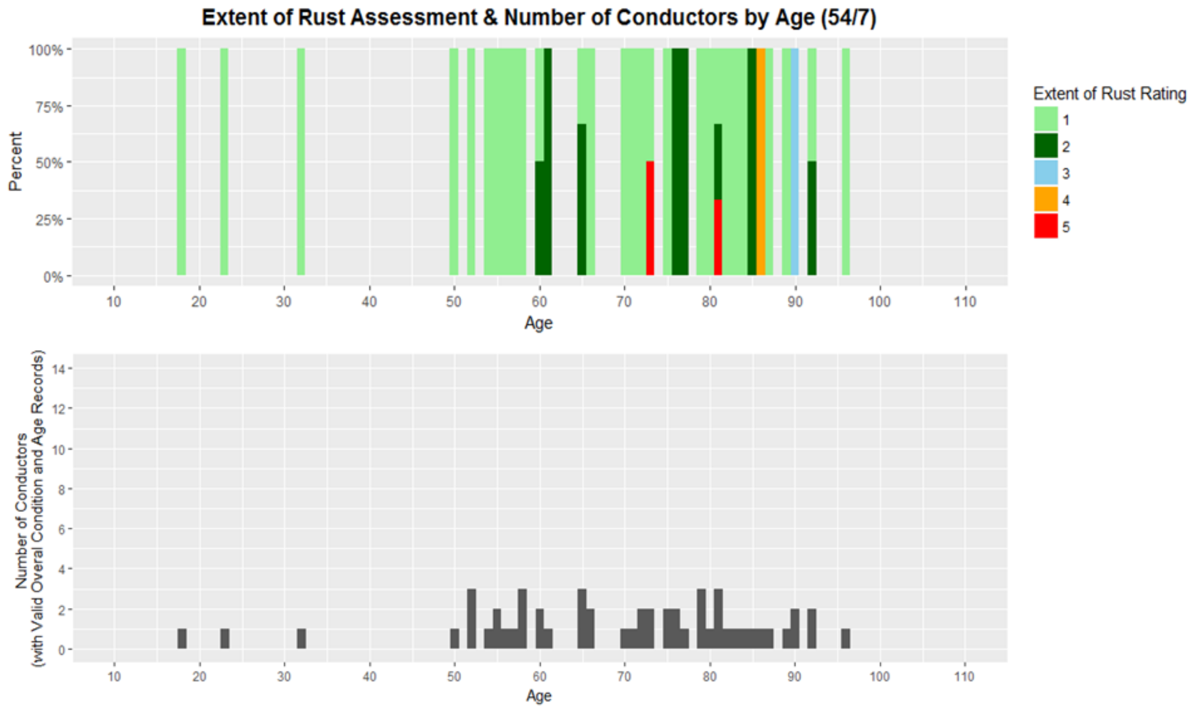


Figure 3-27
Extent of Rust by Age (54/7)

Severity of Rust by Age (26/7 Drake)

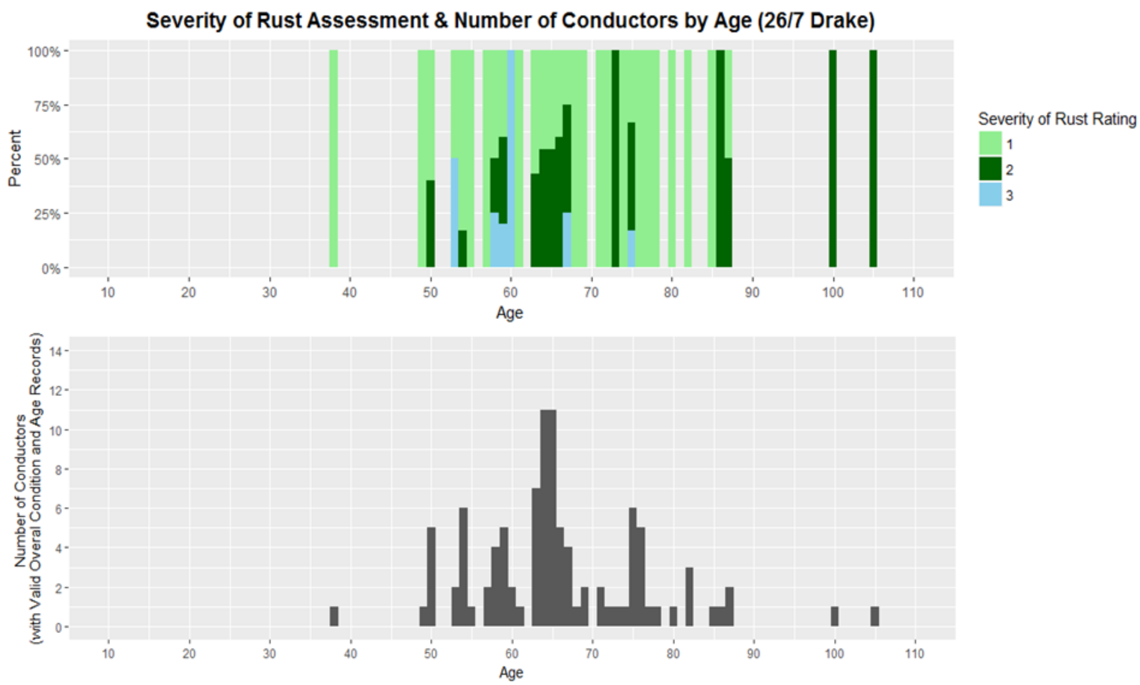


Figure 3-28
Severity of Rust by Age (26/7 Drake)

Severity of Rust by Age (26/7 Non-Drake)

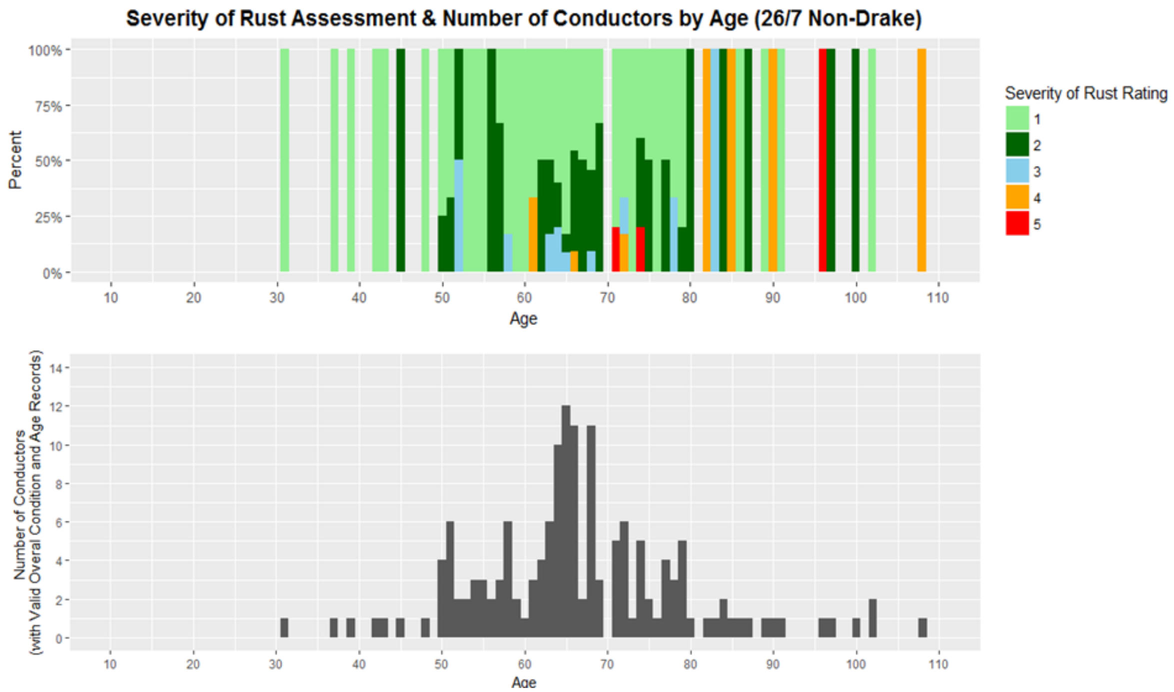


Figure 3-29
Severity of Rust by Age (26/7 Non-Drake)

Severity of Rust by Age (54/7)

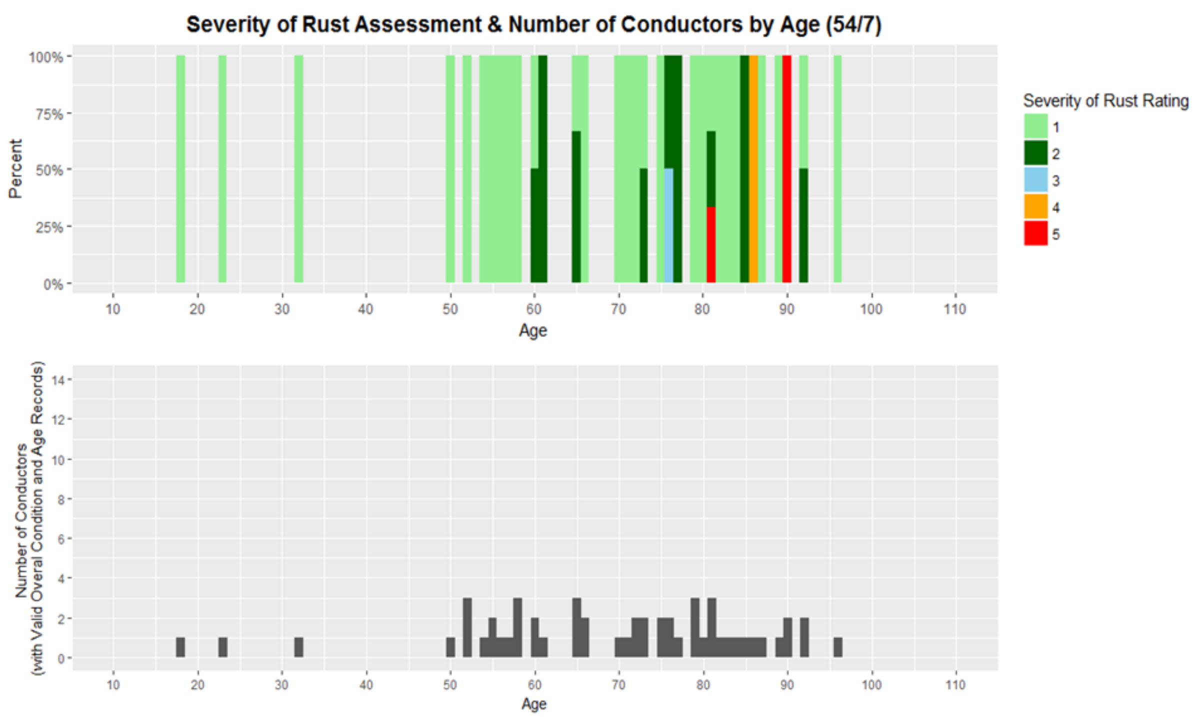


Figure 3-30
Severity of Rust by Age (54/7)

Severity vs. Extent of Rust (26/7 Drake)

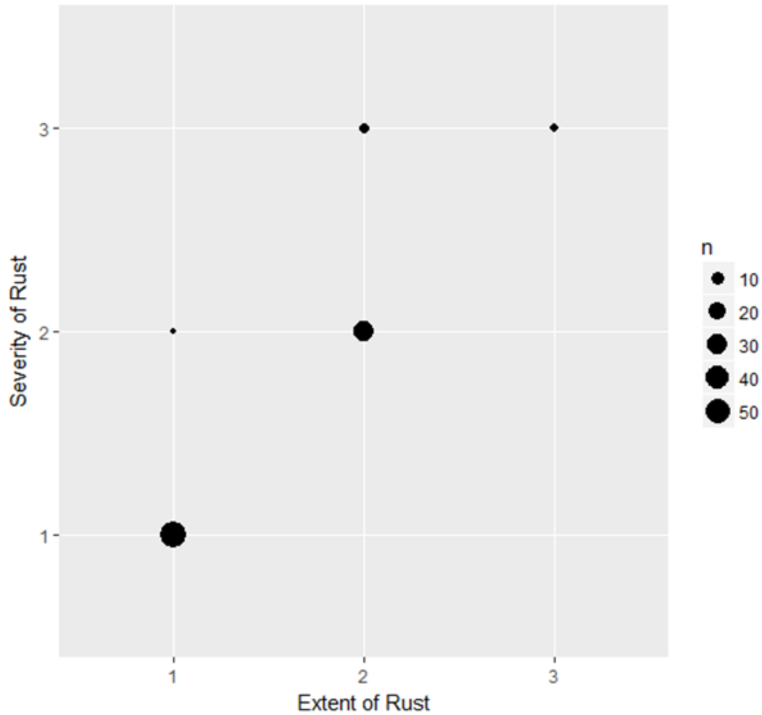


Figure 3-31
Severity vs. Extent of Rust (26/7 Drake)

Severity vs. Extent of Rust (26/7 Non-Drake)

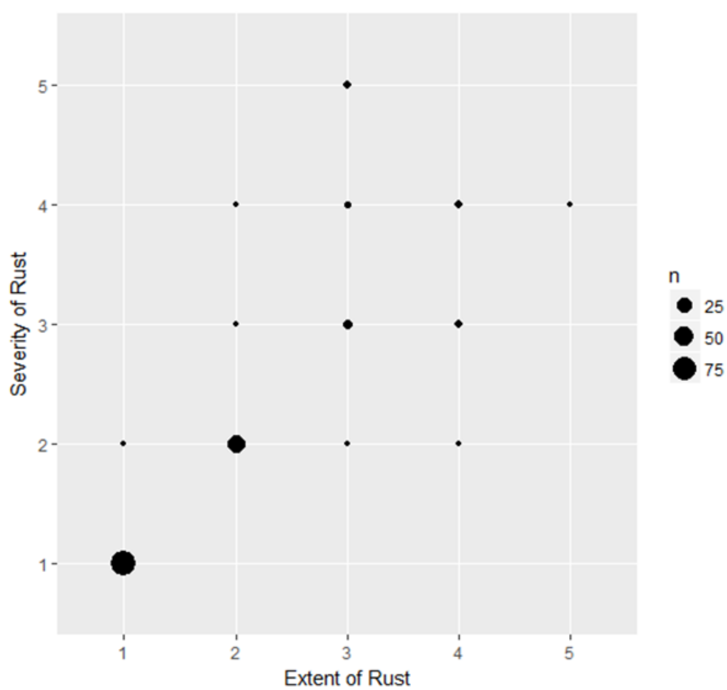


Figure 3-32
Severity vs. Extent of Rust (26/7 Non-Drake)

Severity vs. Extent of Rust (54/7)

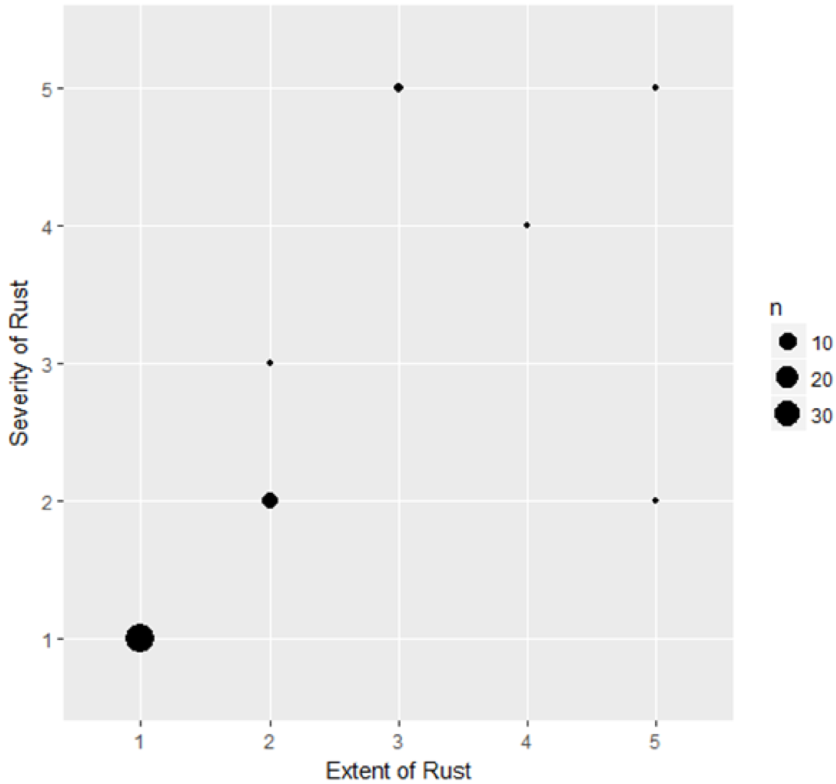


Figure 3-33
Severity vs. Extent of Rust (54/7)

Remaining Zinc

Remaining Zinc (%) by Age (26/7 Drake)

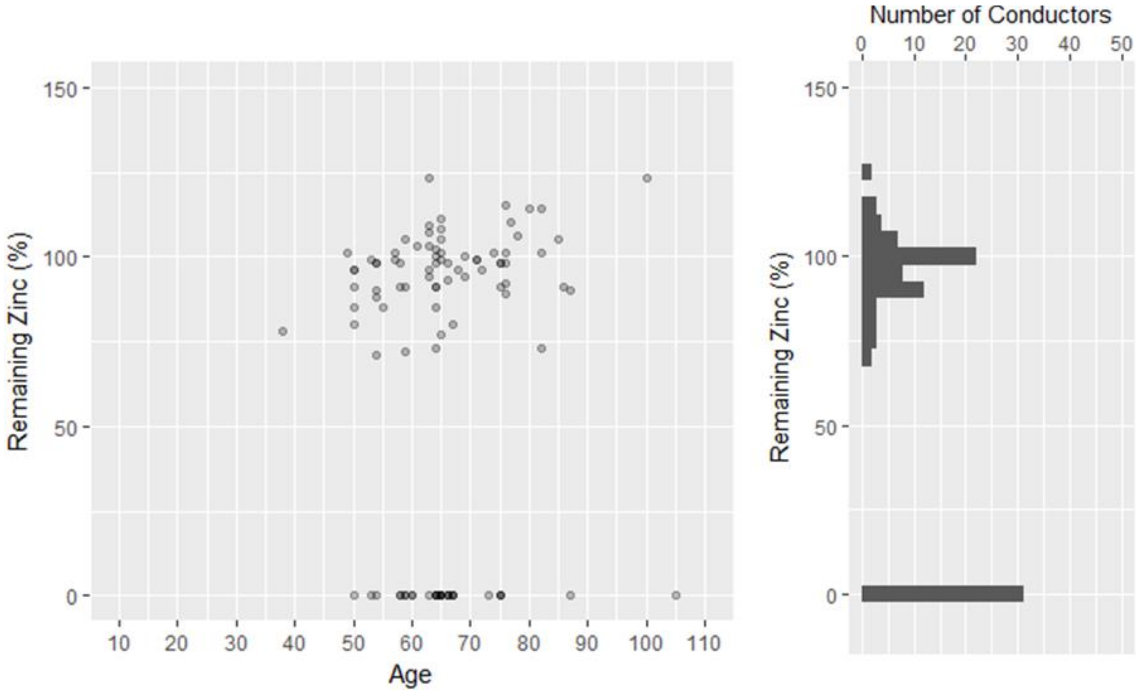


Figure 3-34
Remaining Zinc (%) by Age (26/7 Drake)

Remaining Zinc (%) by Age (26/7 Non-Drake)

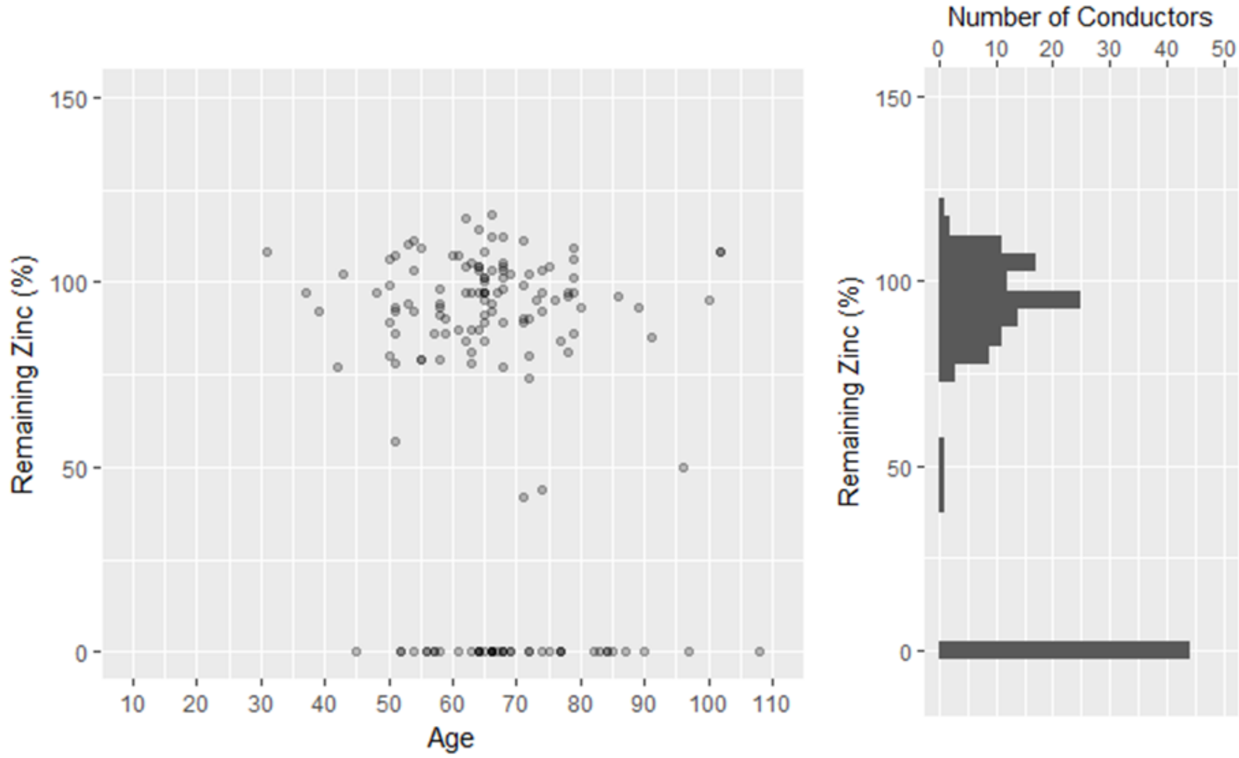


Figure 3-35
Remaining Zinc (%) by Age (26/7 Non-Drake)

Remaining Zinc (%) by Age (54/7)

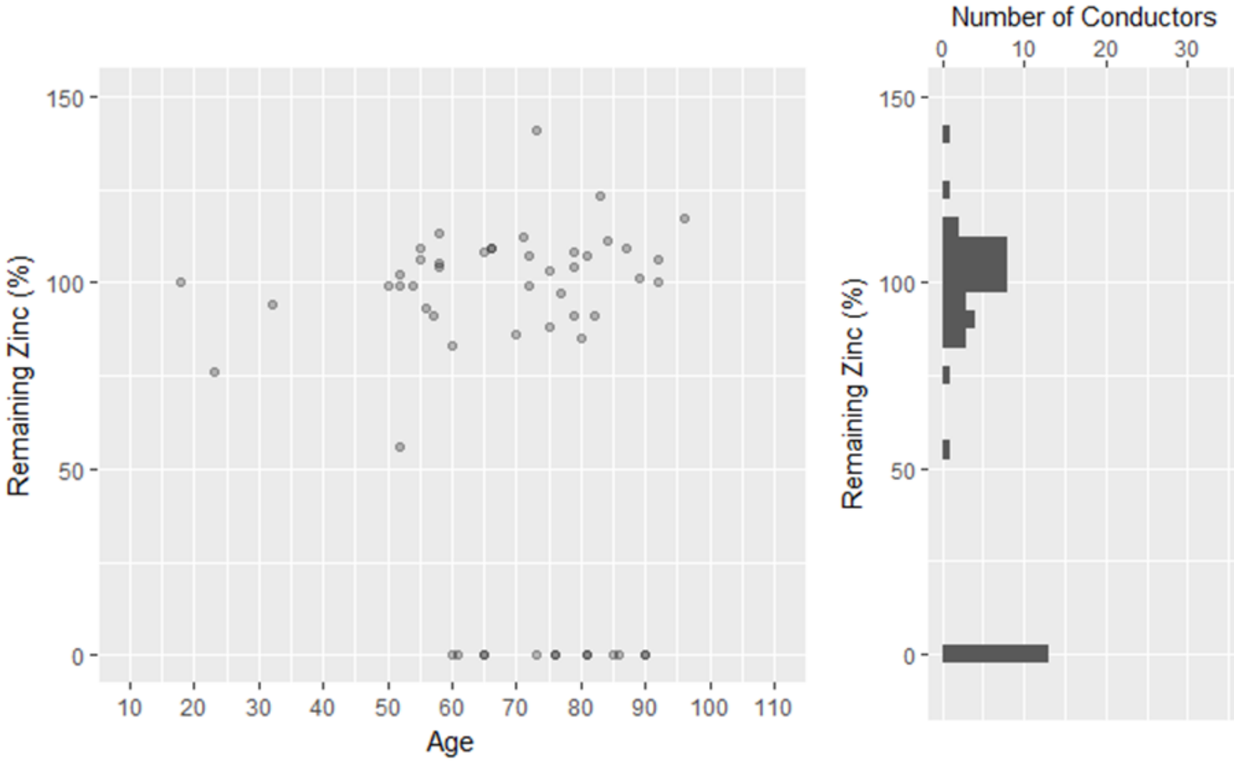


Figure 3-36
Remaining Zinc (%) by Age (54/7)

Torsional Ductility

Torsional Ductility by Age (26/7 Drake)

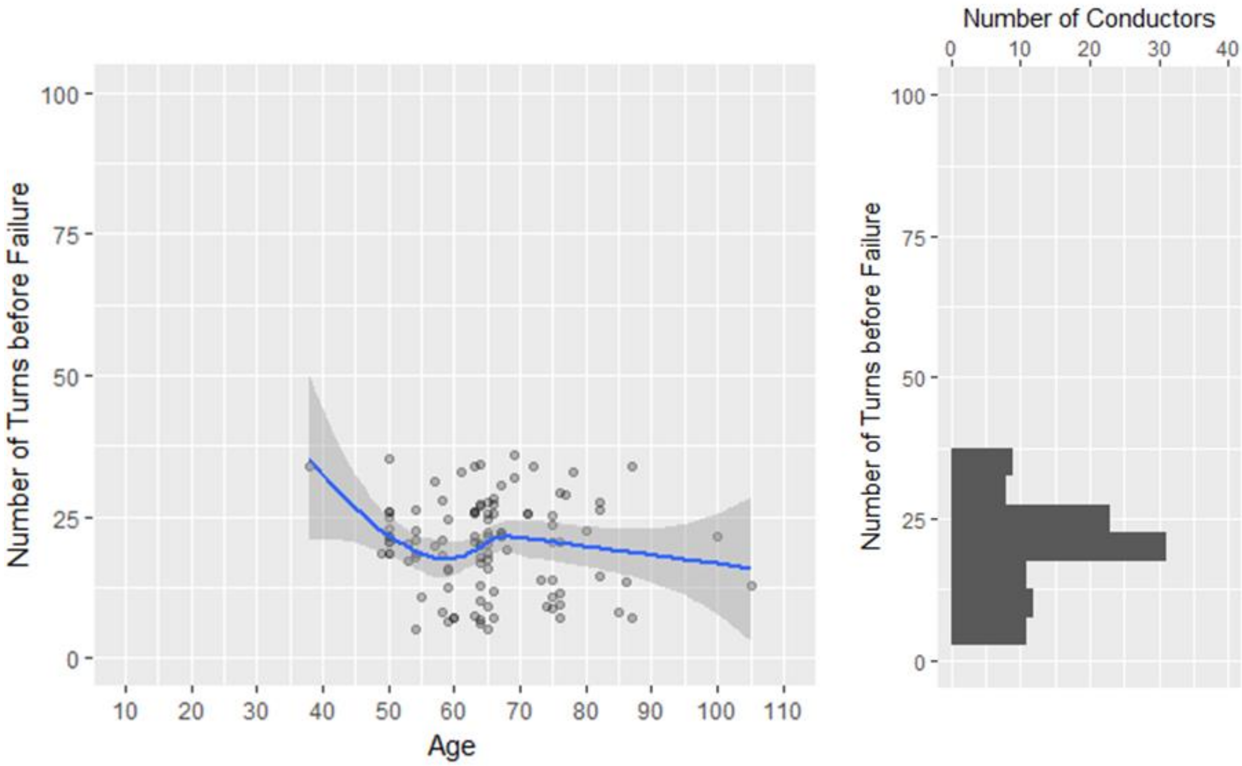


Figure 3-37
Torsional Ductility by Age (26/7 Drake)

Torsional Ductility by Age (26/7 Non-Drake)

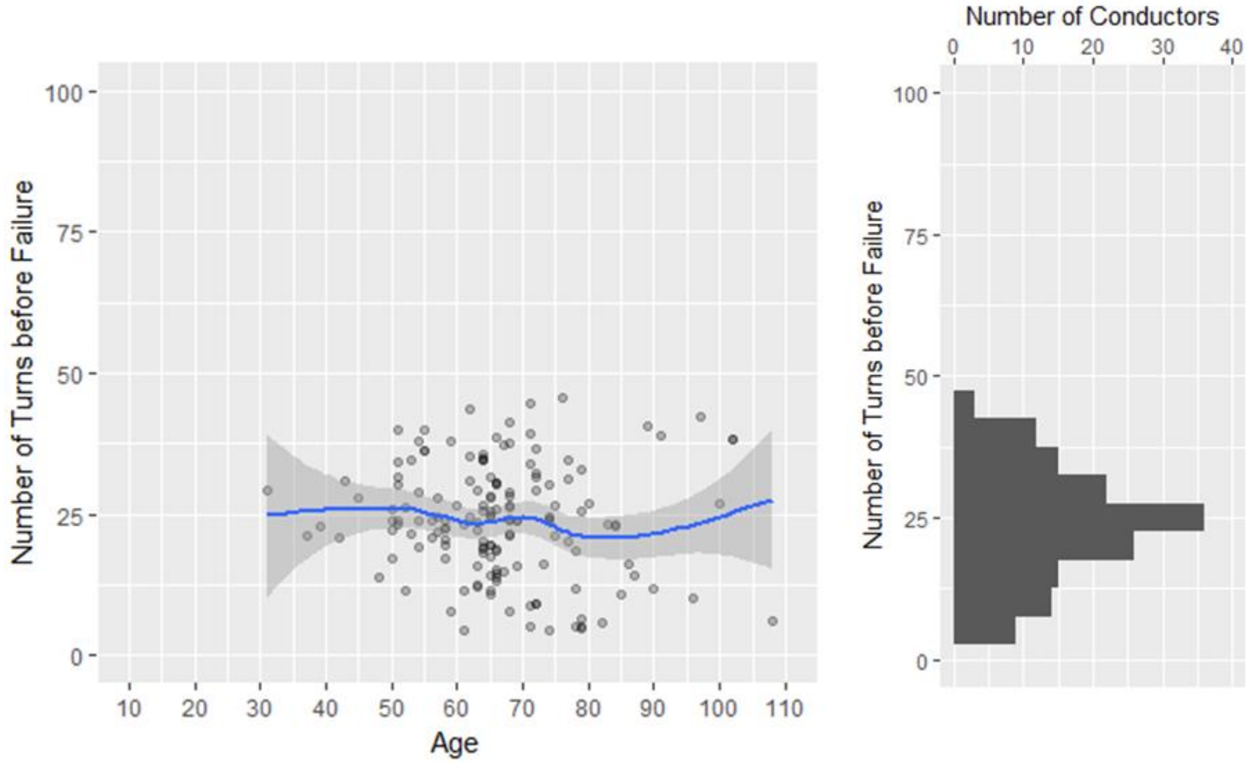


Figure 3-38
Torsional Ductility by Age (26/7 Non-Drake)

Torsional Ductility by Age (54/7)

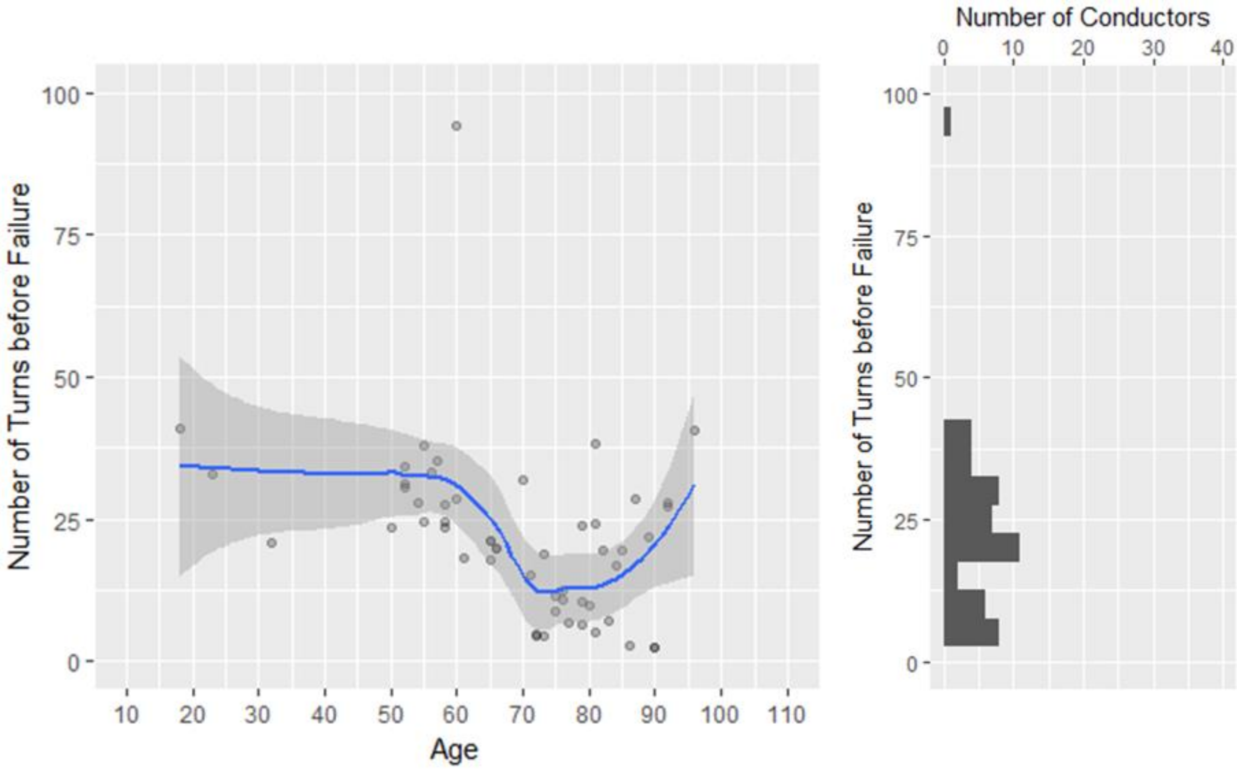


Figure 3-39
Torsional Ductility by Age (54/7)

Tensile Strength

Tensile Strength by Age (26/7 Drake)

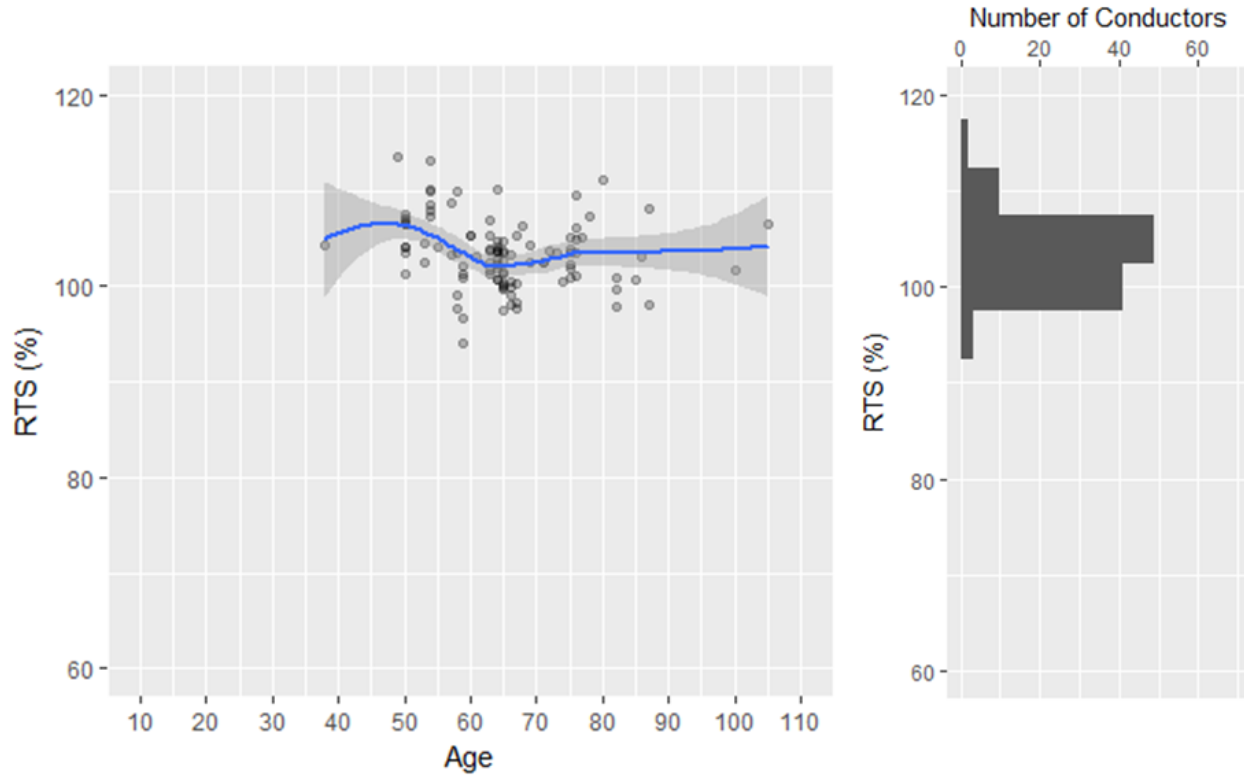


Figure 3-40
Tensile Strength by Age (26/7 Drake)

Tensile Strength by Age (26/7 Non-Drake)

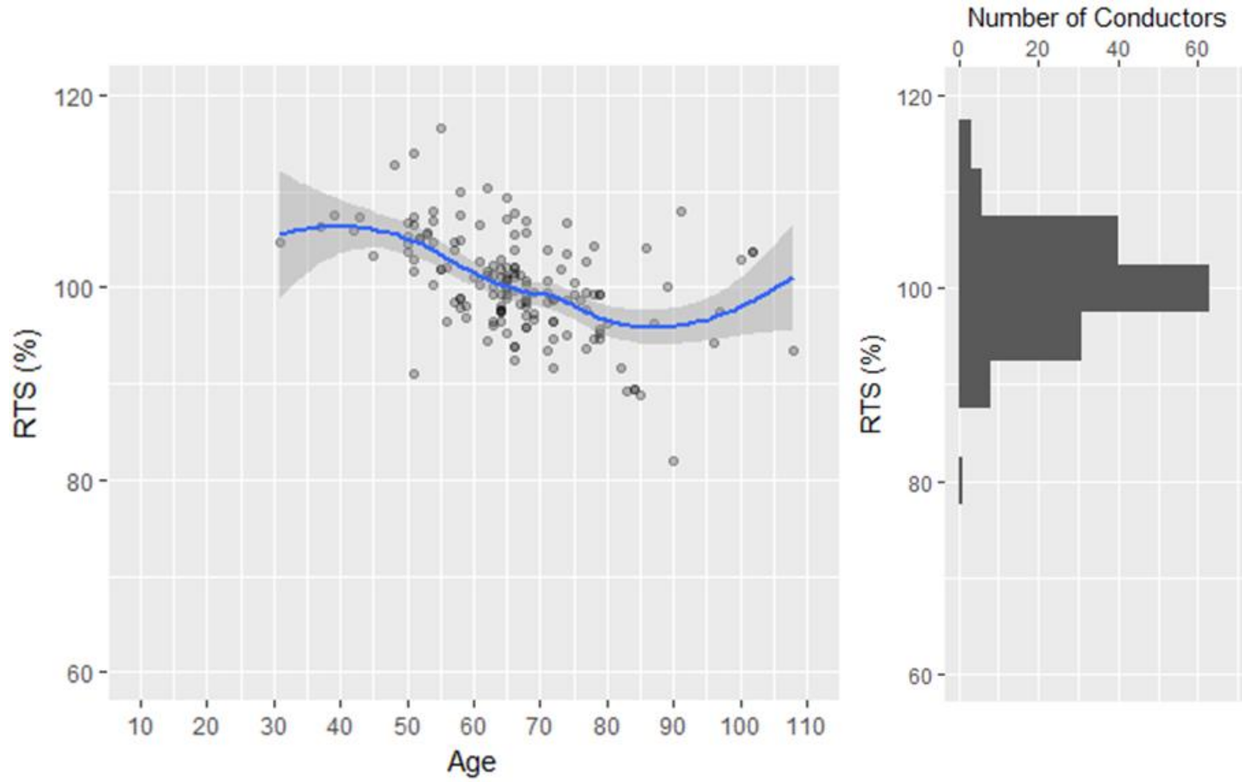


Figure 3-41
Tensile Strength by Age (26/7 Non-Drake)

Tensile Strength by Age (54/7)

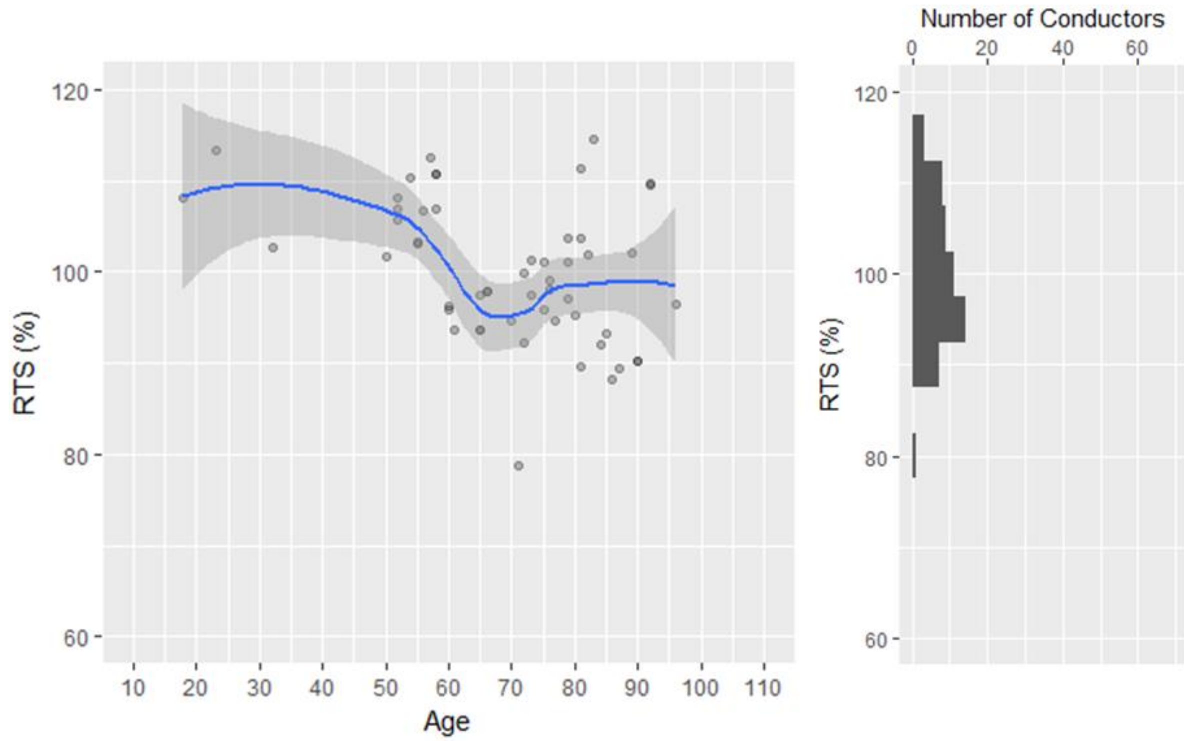


Figure 3-42
Tensile Strength by Age (54/7)

Summary: Exploratory Analyses of the Three Subsets of Data

To review, the following three subsets of data were investigated:

- 26/7 Drake
- 26/7 Non-Drake
- 54/7

Even with these more homogeneous (though smaller) data subsets, Age does not appear to have a significant correlation with overall condition or any of the constituent conditions (assessment factors).

Next Steps

Investigators next narrowed in on even smaller data subsets where both stranding and size are homogeneous within each subset, without sacrificing too much on sample size

The investigation focused on the following stranding and size subsets of data:

- 26/7 and 795.0 kcmil
- 26/7 and 477.0 kcmil
- 54/7 and 605.0 kcmil

For each subset, the project team investigated:

- Remaining zinc by age and corrosion zone
- Torsional ductility by age
- Tensile strength by age

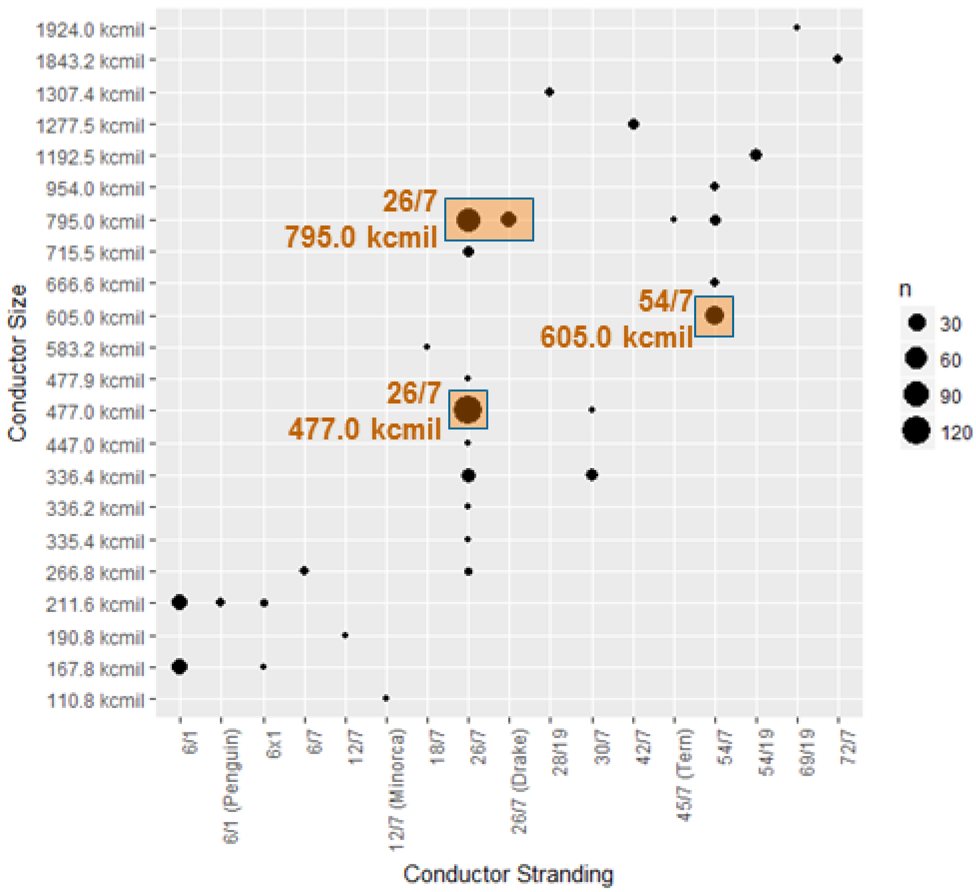


Figure 3-43
Conductor Stranding/Size Subsets Examined for Remaining Zinc, Torsional Ductility and Tensile Strength by Age

Remaining Zinc (%) by Age

Figure 3-44 shows remaining zinc by age, overlaying three groups of data. The plot does not reveal a clear age-related pattern for remaining zinc.

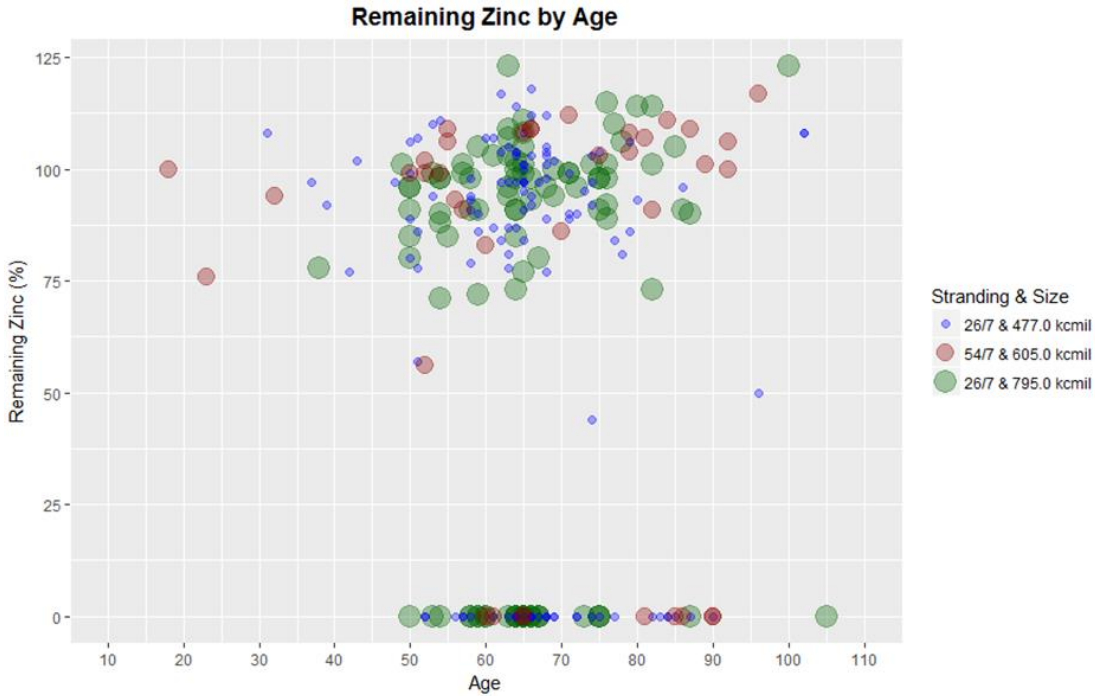


Figure 3-44
Remaining Zinc by Age for Three Stranding/Size Subsets

Figure 3-45 shows remaining zinc by age, with trend lines added, revealing even less of a clear pattern.

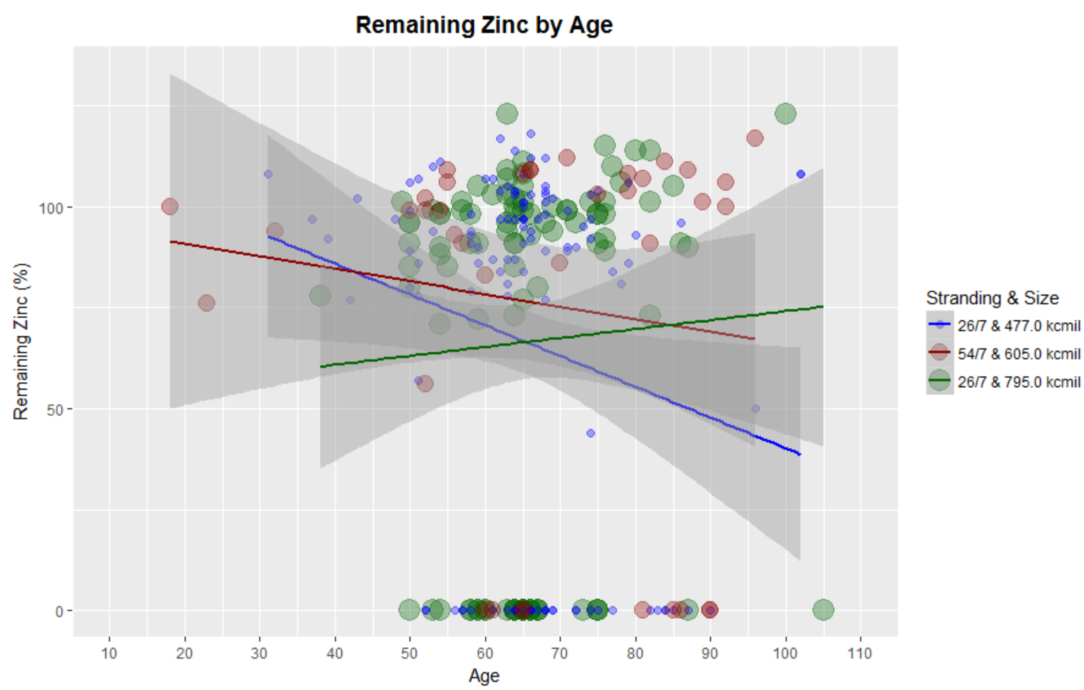


Figure 3-45
Remaining Zinc by Age: Trend Lines

Figure 3-46 shows remaining zinc by age, as well as age and density demographics. Again, no clear age-related pattern is evident.

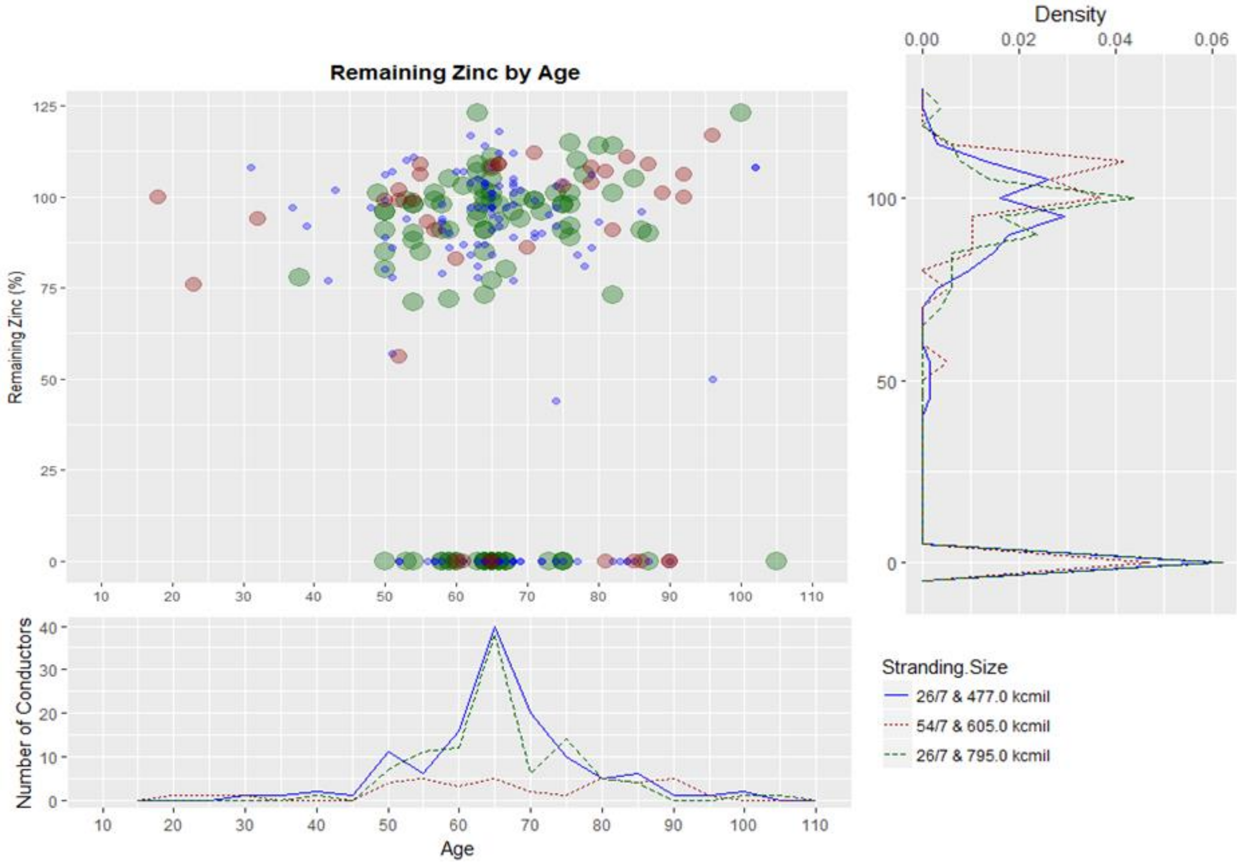


Figure 3-46
Remaining Zinc by Age with Demographics (Age, Density)

Remaining Zinc by Age and Corrosion Zone

The project team next investigated the relationship of remaining zinc and corrosion zone. The data did not show that corrosion zone was a significant factor in zinc loss.

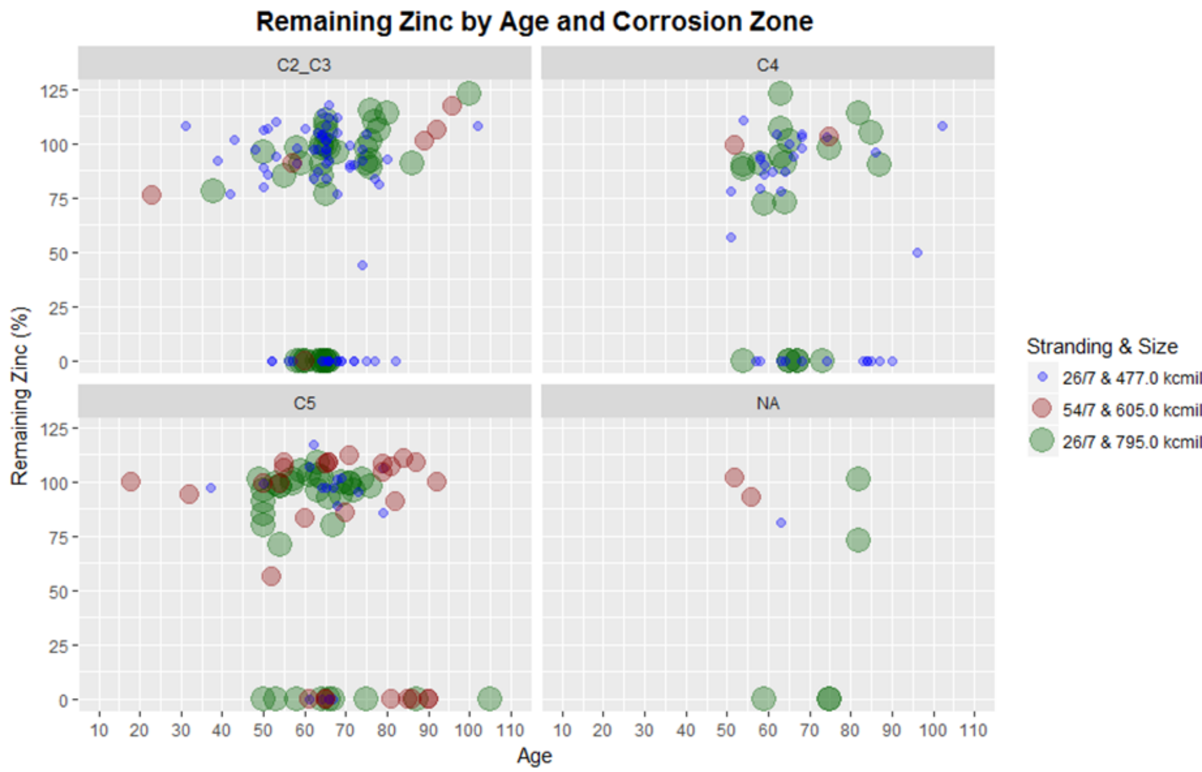


Figure 3-47
Remaining Zinc by Age and Corrosion Zone

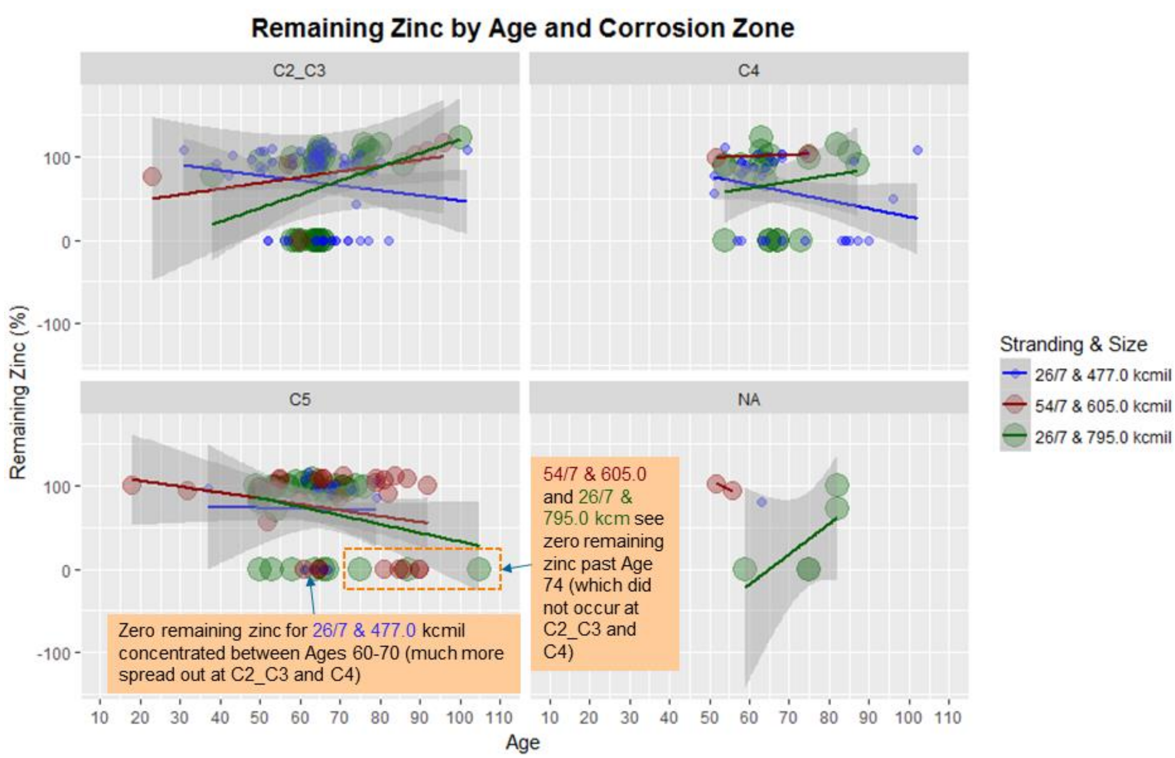


Figure 3-48
Remaining Zinc by Age and Corrosion Zone: Trend Lines

The following figures show no clear correlation between remaining zinc and age for all corrosion zone categories.

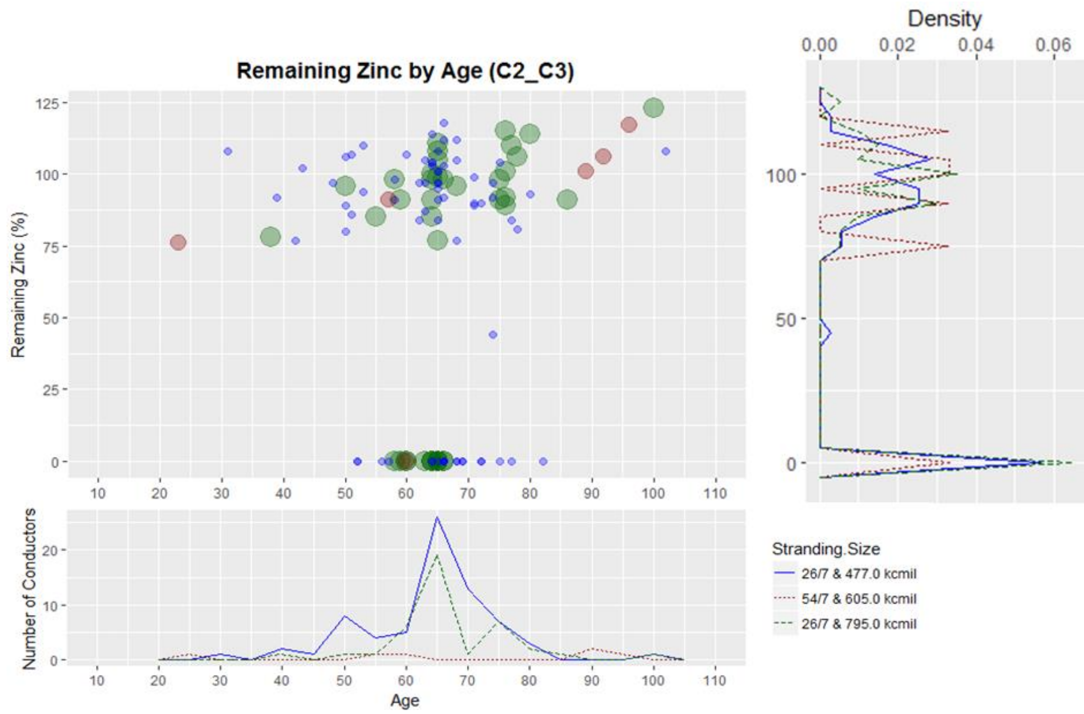


Figure 3-49
Remaining Zinc by Age: Corrosion Zones C2-C3

Figure 3-50
Remaining Zinc by Age: Corrosion Zone C4

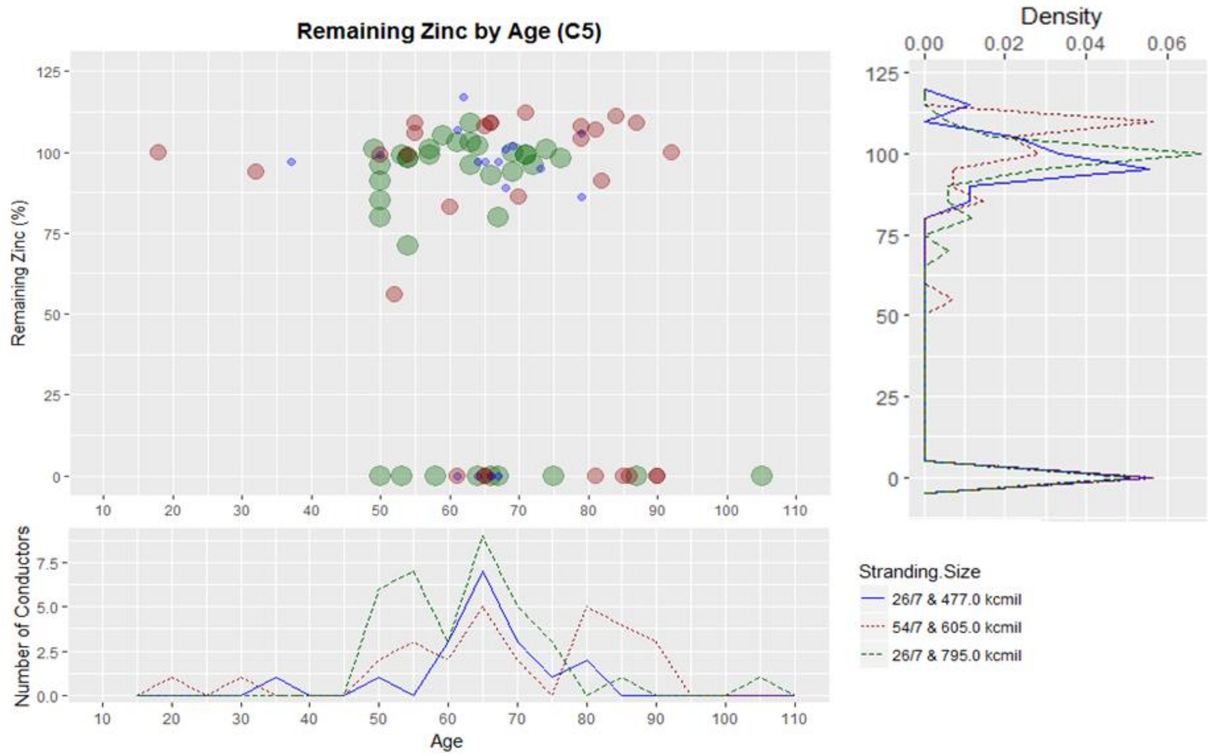


Figure 3-51
Remaining Zinc by Age: Corrosion Zone C5

Torsional Ductility by Age

Researchers next examined torsional ductility by age for the same three conductor subsets:

- 26/7 and 795.0 kcmil
- 26/7 and 477.0 kcmil
- 54/7 and 605.0 kcmil

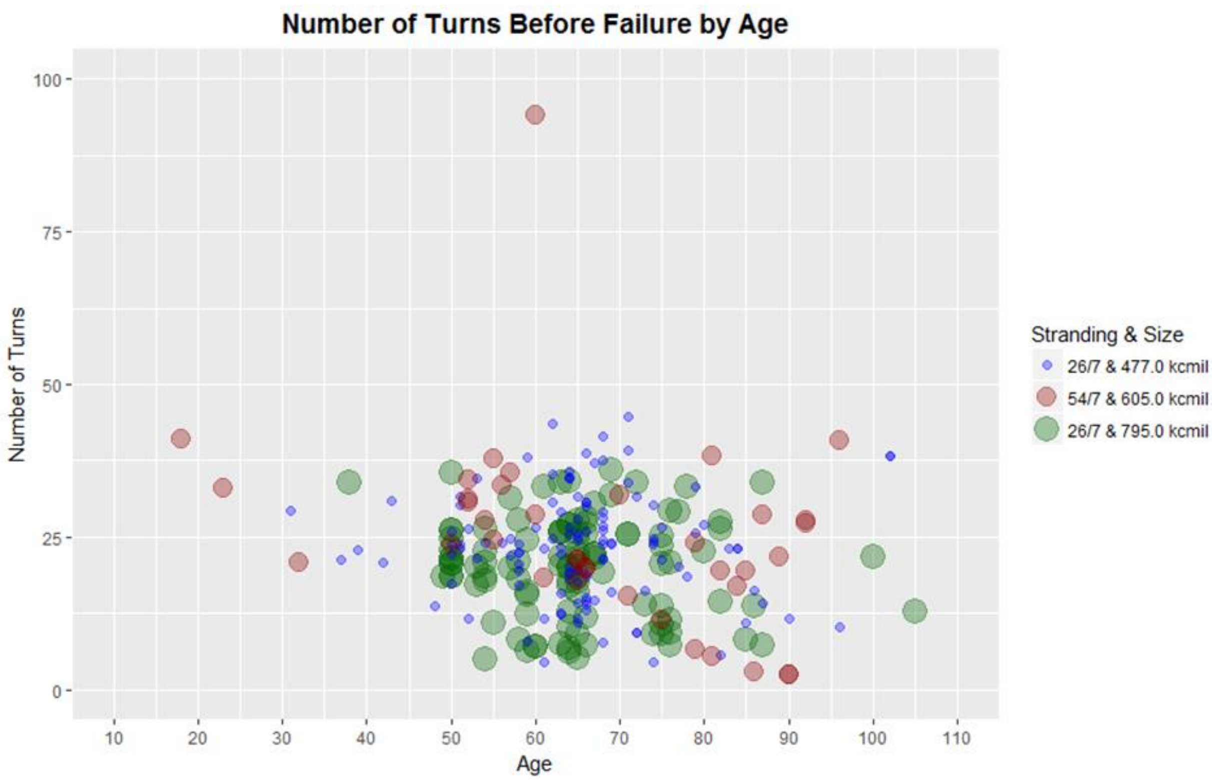


Figure 3-52
Torsional Ductility by Age

In terms of torsional ductility, 54/7 & 605.0 kcmil (i.e. more aluminum strands) seem to be more negatively affected by Age.

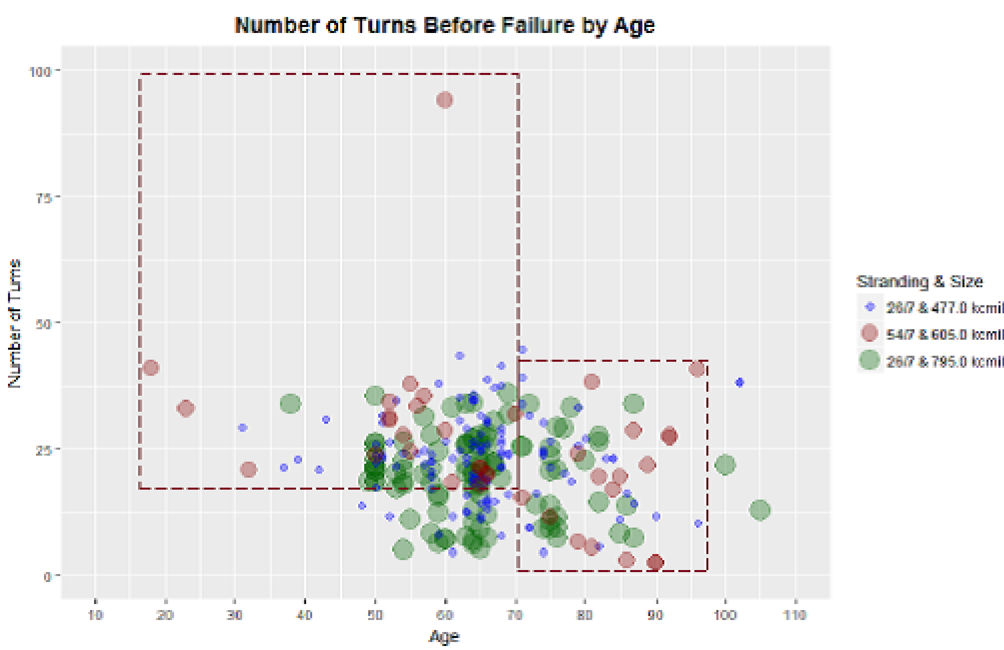


Figure 3-53
Torsional Ductility: Number of Turns Before Failure by Age

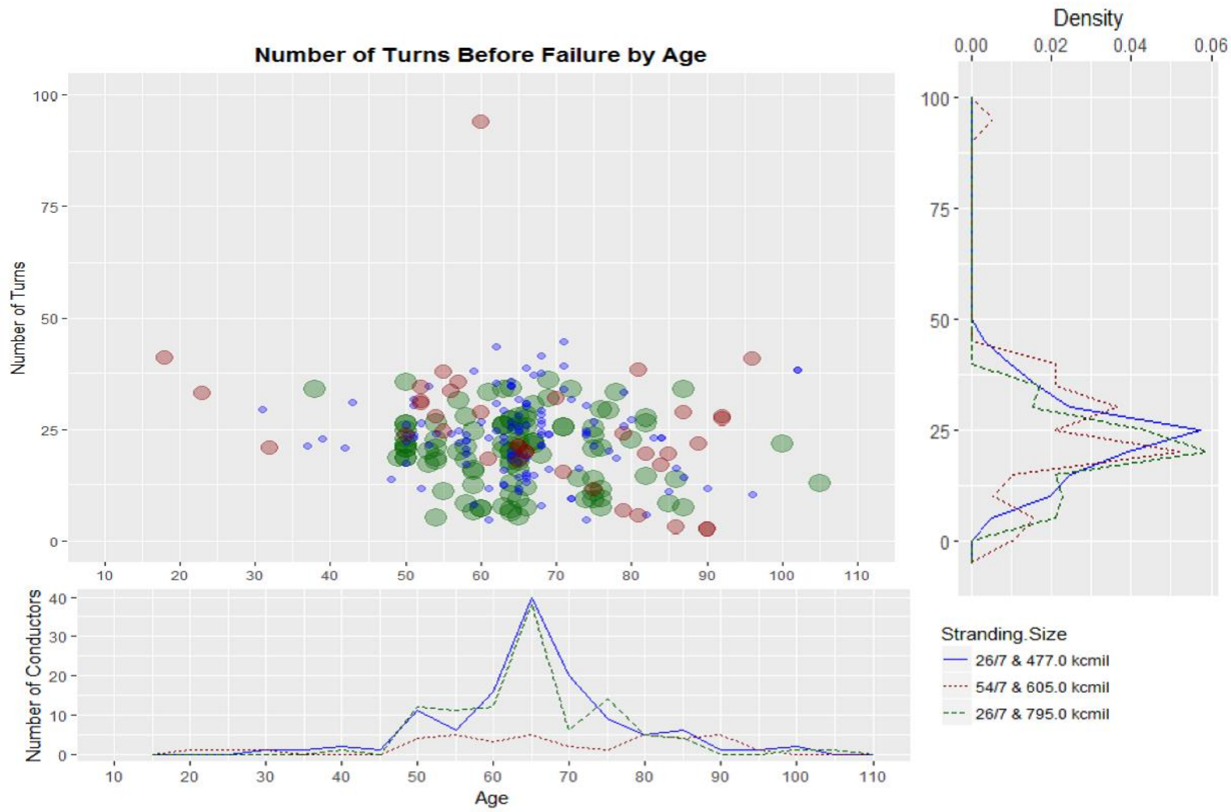


Figure 3-54
Torsional Ductility: Demographics

Tensile Strength by Age

The project team next investigated tensile strength by age for the same three conductor subsets:

- 26/7 and 795.0 kcmil
- 26/7 and 477.0 kcmil
- 54/7 and 605.0 kcmil

As shown in the following figures, there seems to be a general trend of decreased tensile strength with increased age. The conductor subset with the largest size (26/7 &795.0 kcmil) seems to be less affected by age than the two conductor subsets corresponding to 26/7 & 477.0 kcmil and 54/7 & 605.0 kcmil.

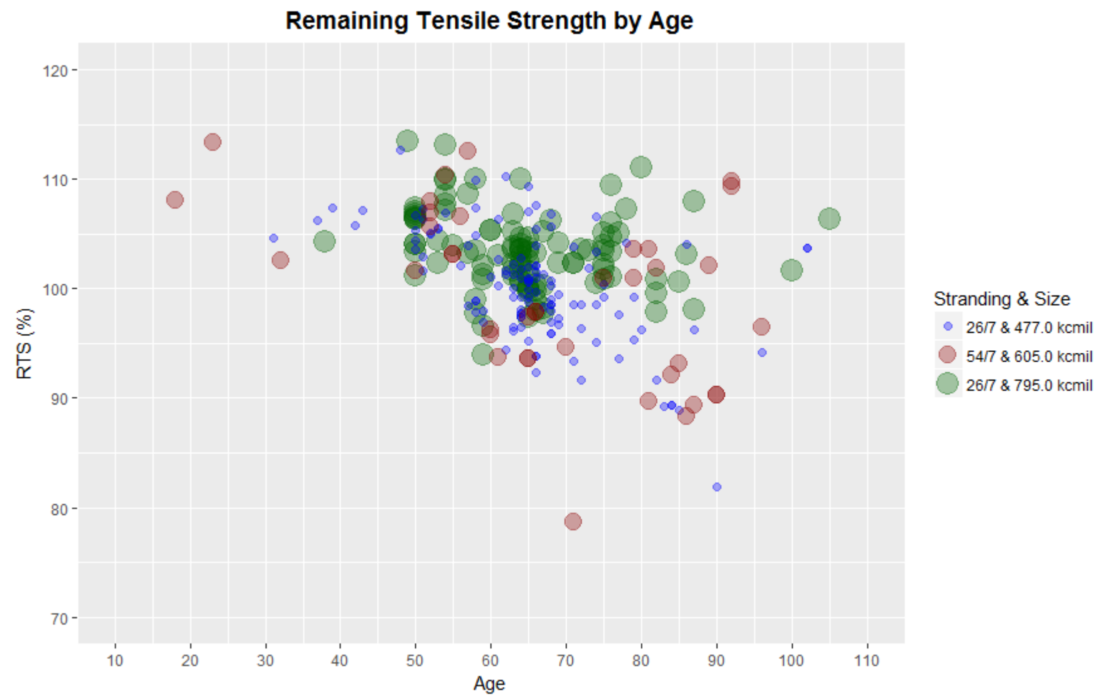


Figure 3-55
Tensile Strength by Age

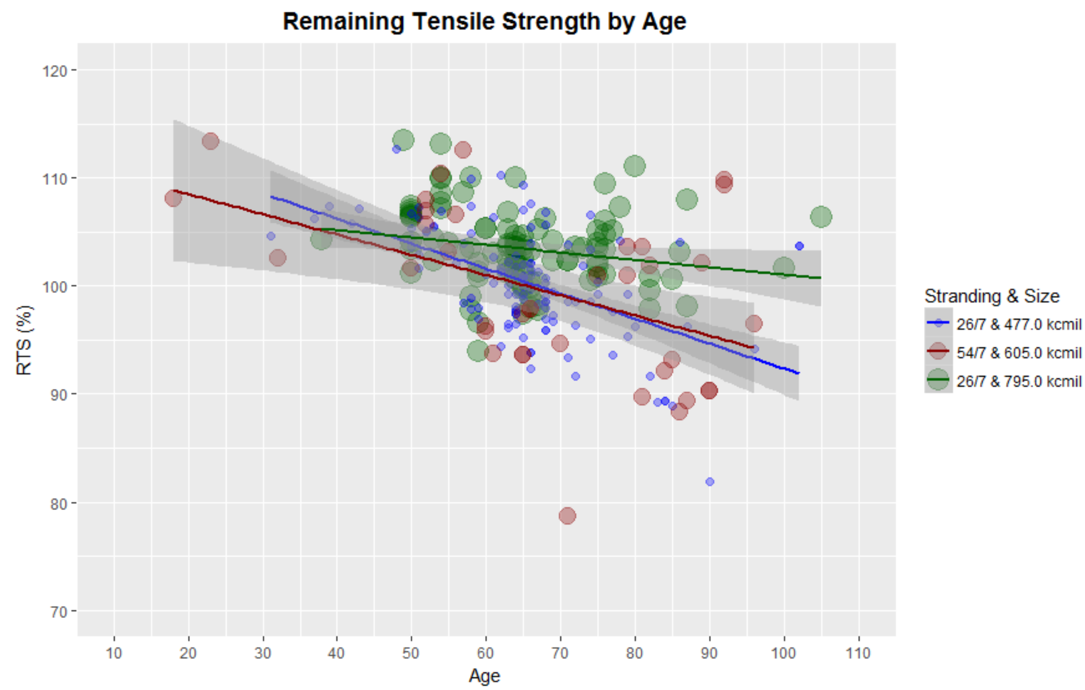


Figure 3-56
Tensile Strength by Age: Trend Lines

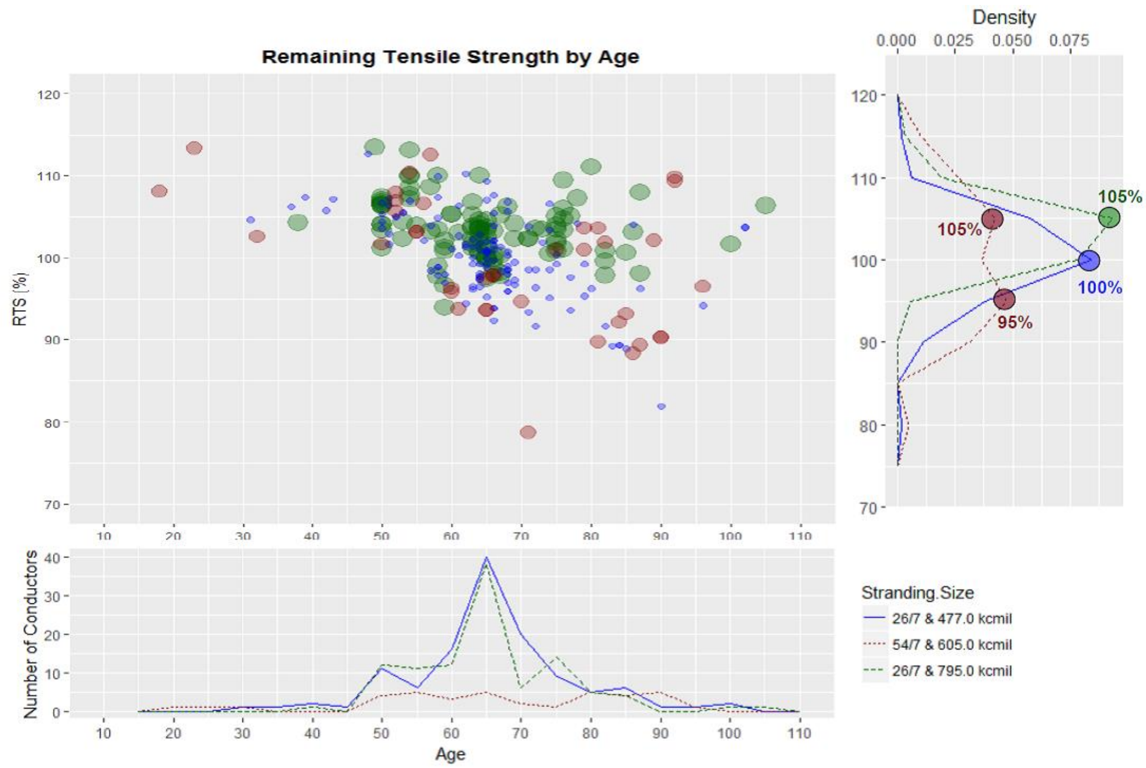


Figure 3-57
Tensile Strength by Age: Demographics

Overall Condition by Age

Researchers next examined the relationship between overall condition and age for the same three conductor subsets. The following figures show no clear age-related patterns.

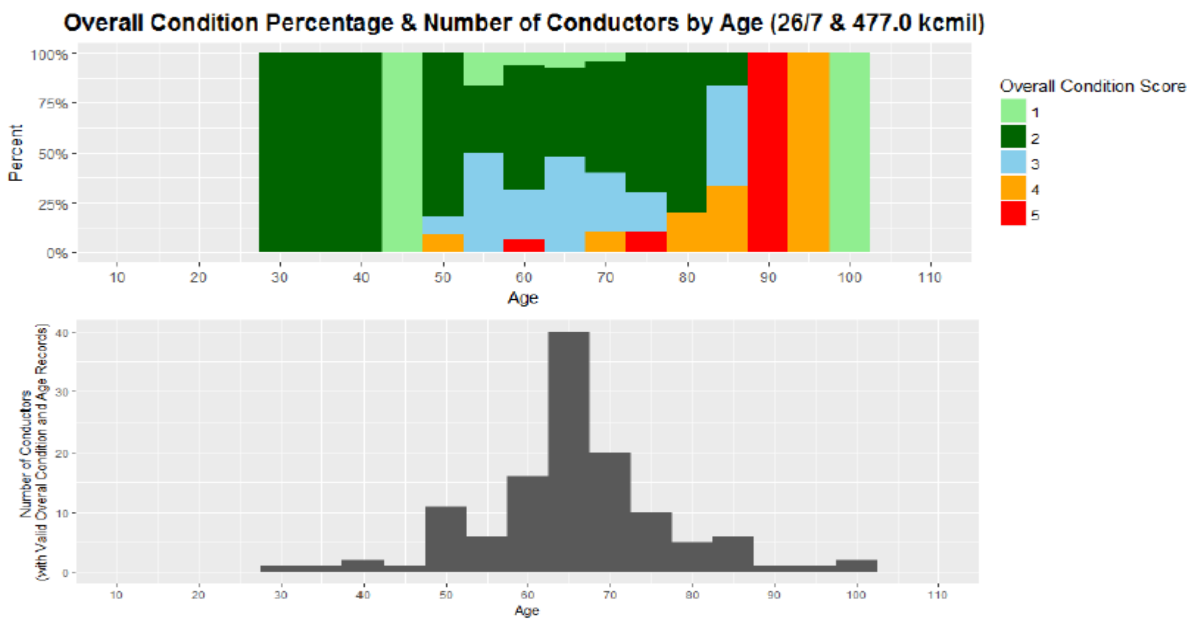


Figure 3-58
Overall Condition by Age (26/7 & 477.0 kcmil)

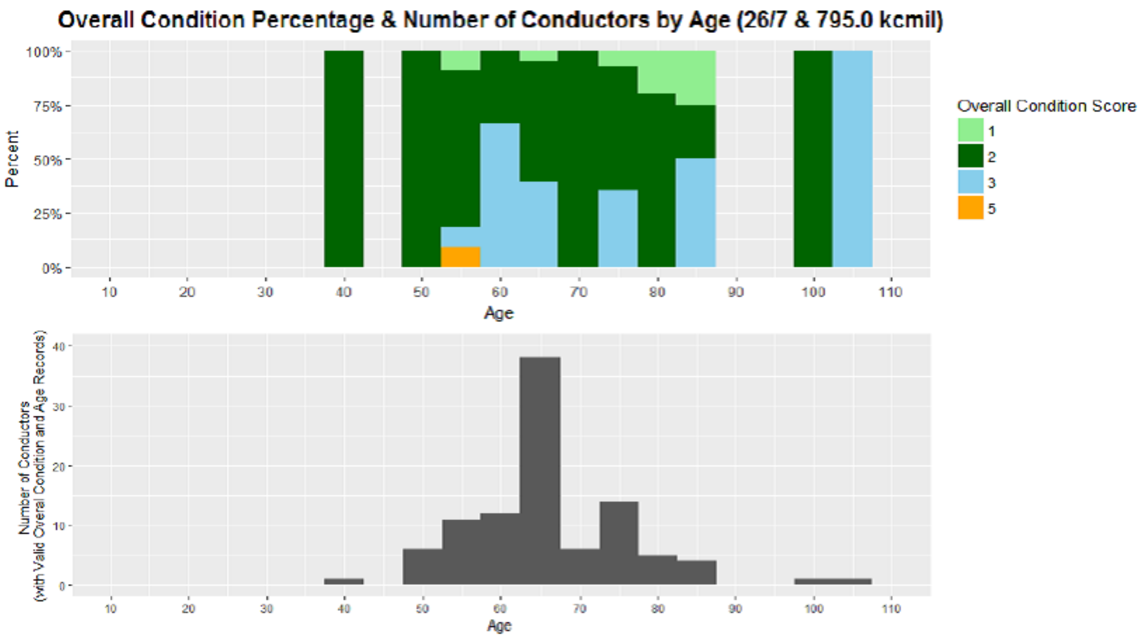


Figure 3-59
Overall Condition by Age (26/7 & 795.0 kcmil)

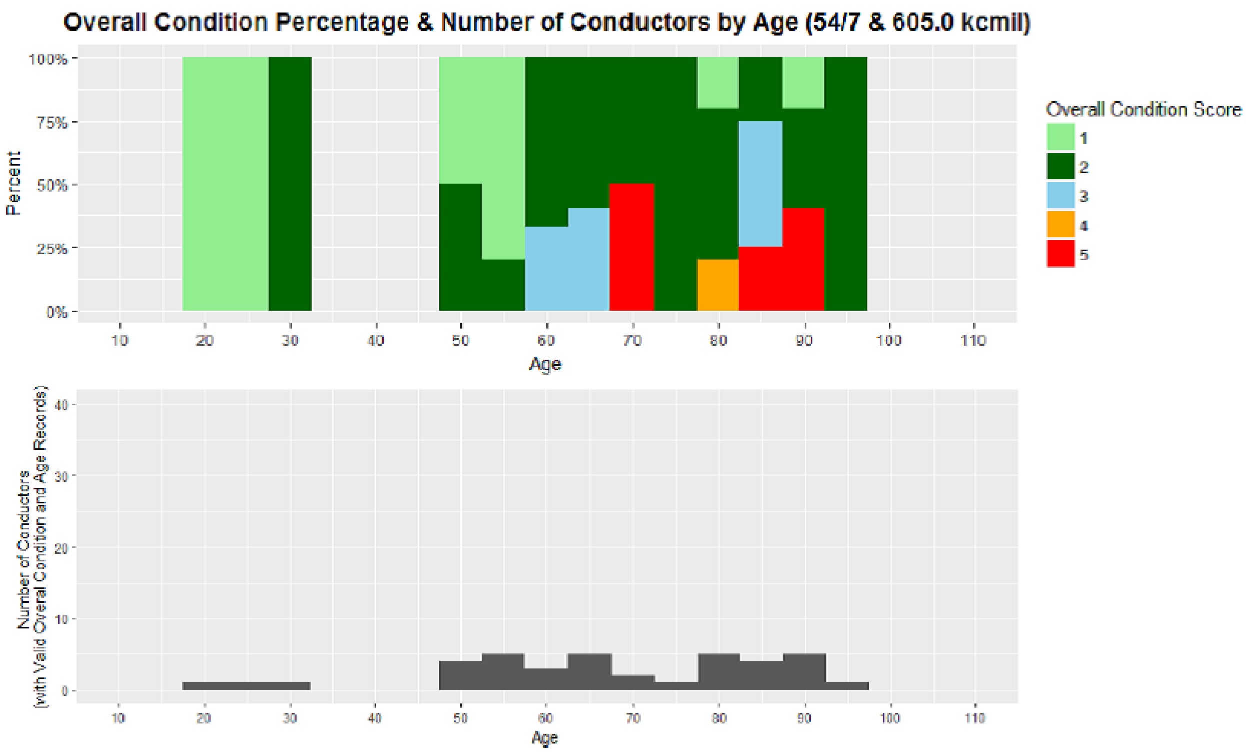


Figure 3-60
Overall Condition by Age (54/7 & 605.0 kcmil)

The investigations focusing on smaller and more homogeneous data sets revealed no clear correlations between overall condition and age, similar to the findings for the larger data set.

Among assessment factors, only torsional ductility and tensile strength have shown some recognizable age-related patterns. Consequently, researchers moved to examined the suitability of considering torsional ductility or tensile strengths as dependent variables (in lieu of overall condition) as a function of age. It is noted that, according to the Hydro One conductor assessment methodology, the end-of-life threshold for torsional ductility is number of turns ≤ 5 and the end-of-life threshold for tensile strength is remaining tensile strength (RTS) ≤ 85%.

Investigation of Failed Sample Data Only

Investigators next examined the conductor assessment data, by looking at:

- Percent of Overall Condition Rating of 5 by Age
- Percent of "Torsional Ductility Failure" (#Turns ≤ 5) by Age
- Percent of "Tensile Strength Failure" (RTS% ≤ 85%) by Age

Data sets examined included three ACSR selected sets as listed below:

- All ACSR
- 26/7 & 795.0 kcmil
- 26/7 & 477.0 kcmil
- 54/7 & 605.0 kcmil

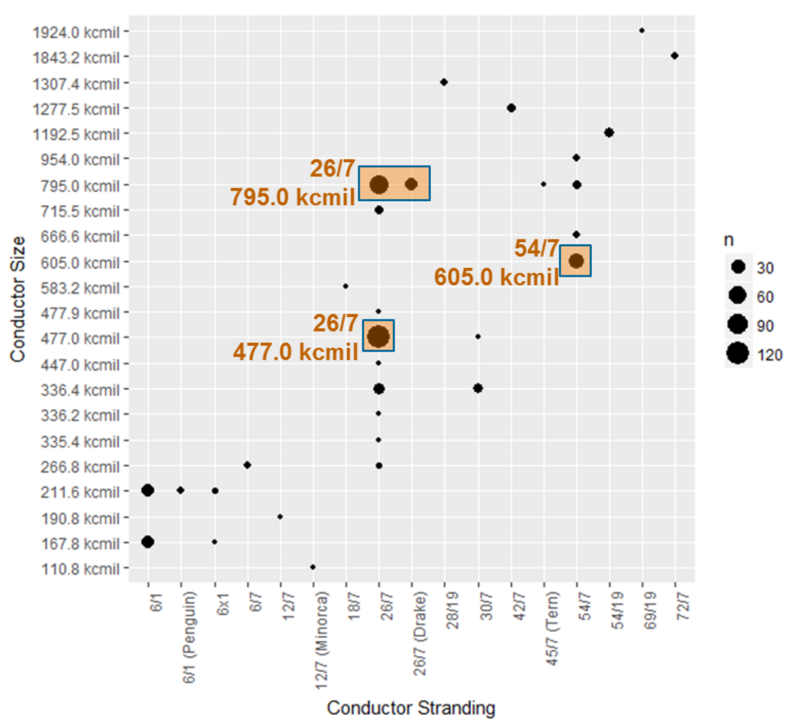


Figure 3-61
Data Sets: 26/7 & 795.0 kcmil, 26/7 & 477.0 kcmil, 54/7 & 605.0 kcmil

Percent of Overall Condition Rating of 5 by Age

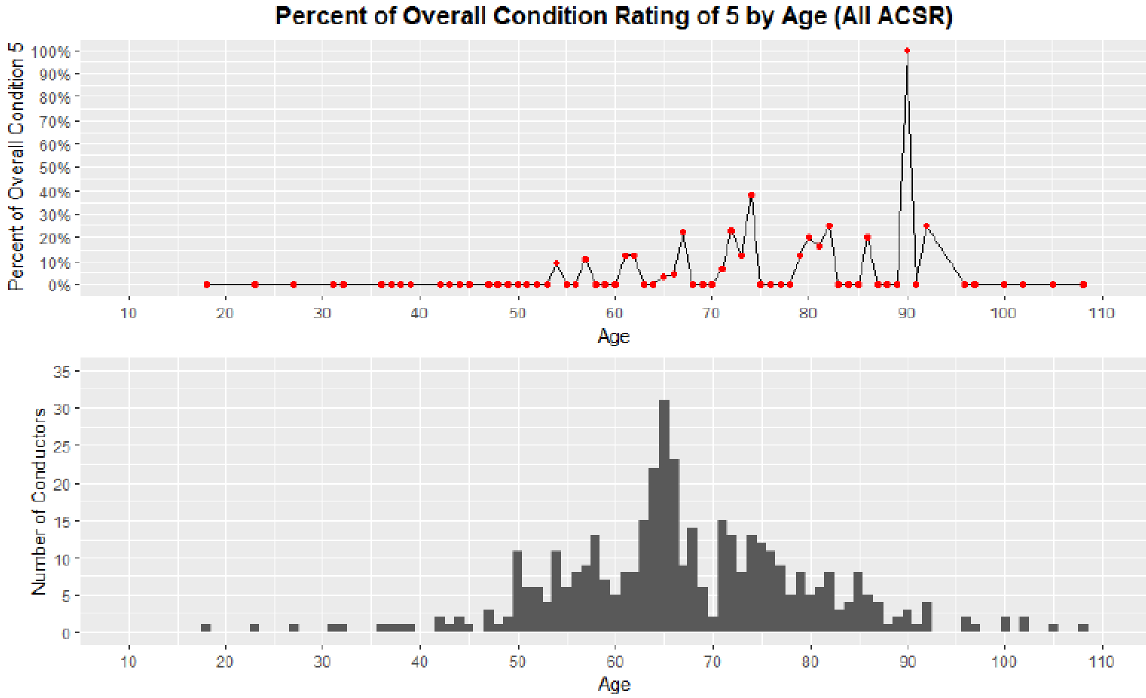


Figure 3-62
Percent of Overall Condition Rating of 5 by Age (All ACSR)

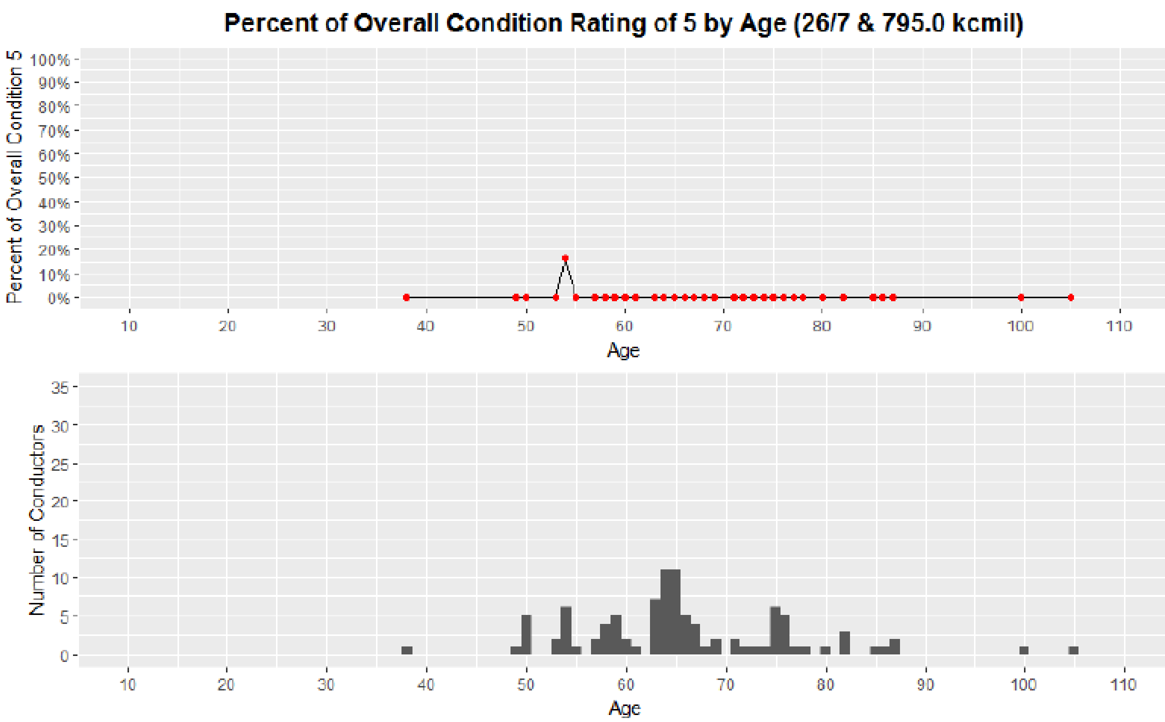


Figure 3-63
Percent of Overall Condition Rating of 5 by Age (26/7 & 795.0 kcmil)

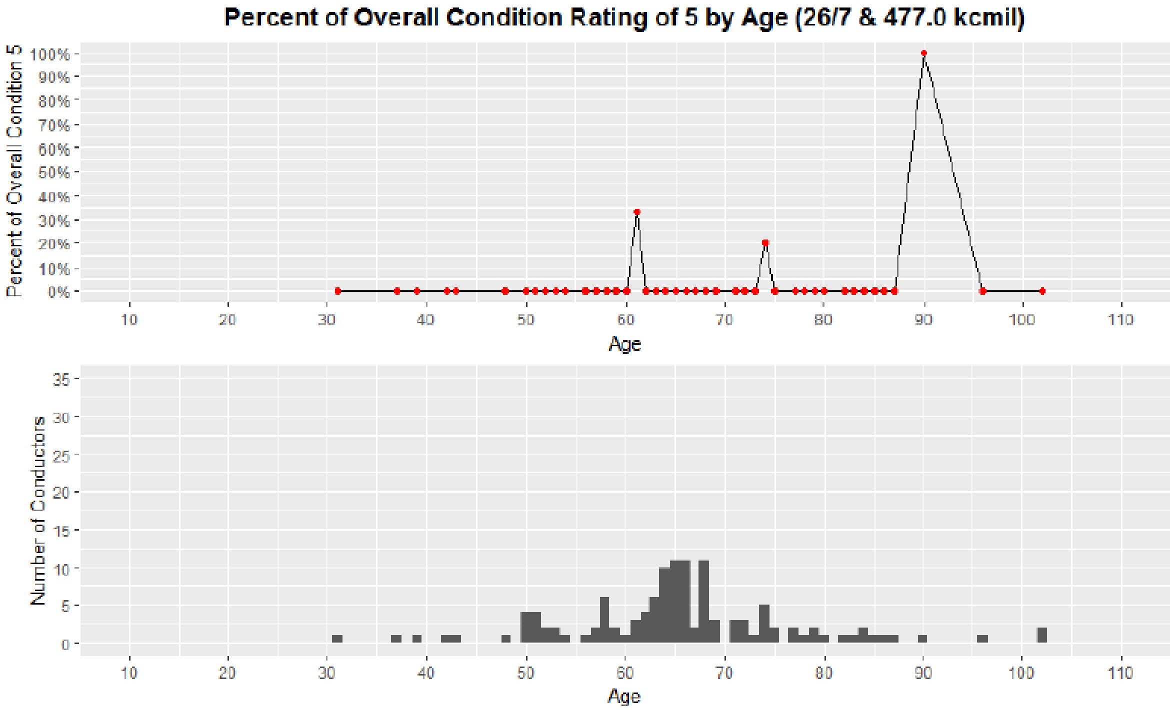


Figure 3-64
Percent of Overall Condition Rating of 5 by Age (26/7 & 477.0 kcmil)

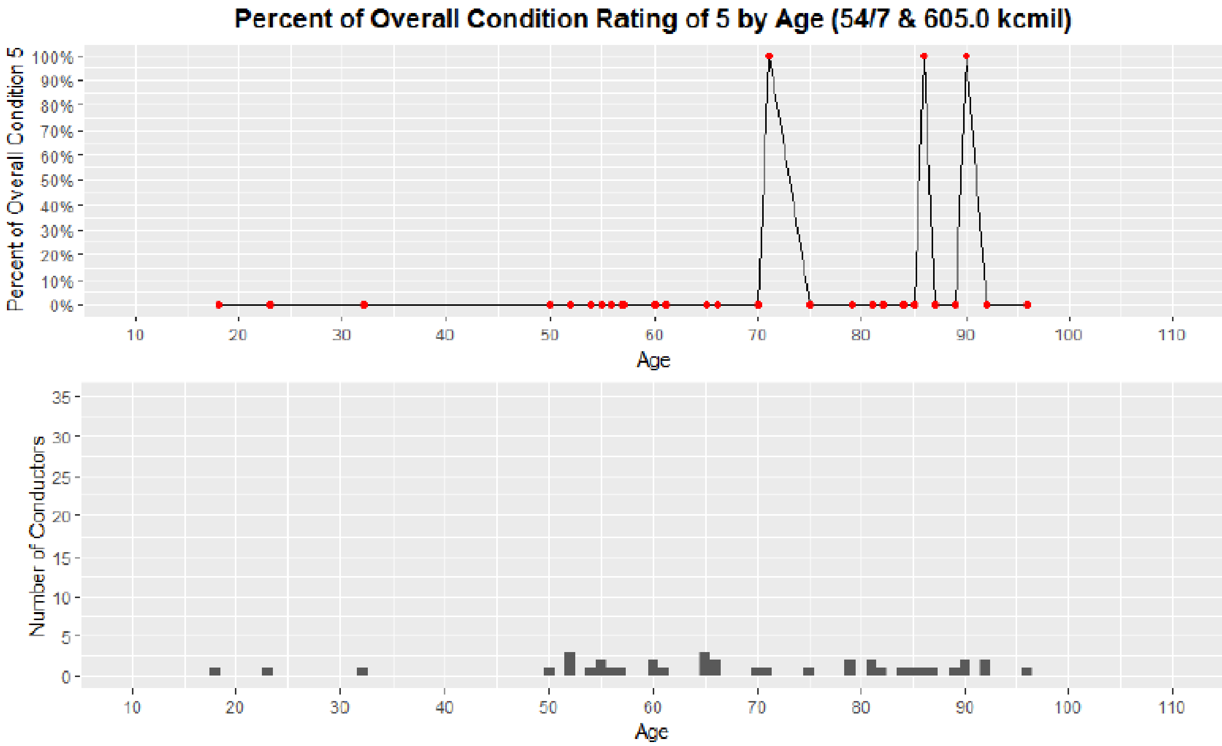


Figure 3-65
Percent of Overall Condition Rating of 5 by Age (54/7 & 605.0 kcmil)

Tensile Strength by Torsional Ductility per Age Group (All ACSR)

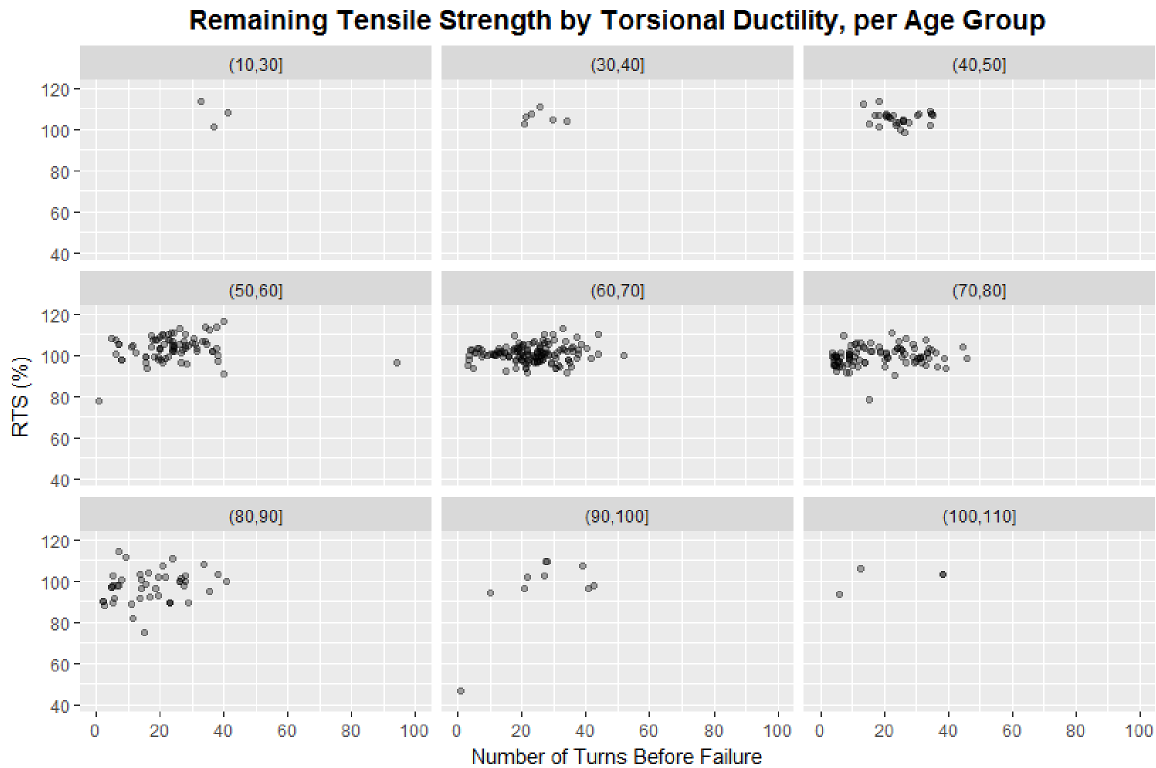


Figure 3-66
Tensile Strength by Torsional Ductility per Age Group (All ACSR)

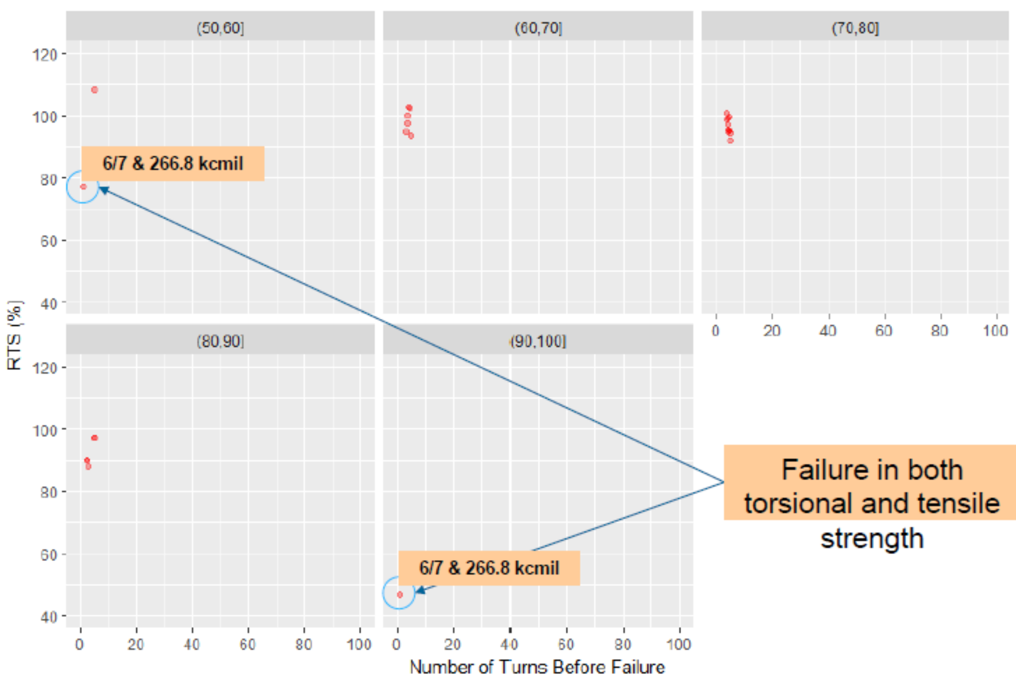


Figure 3-67
Torsional Ductility Failure by (#Turns ≤ 5) Age Group (All ACSR)

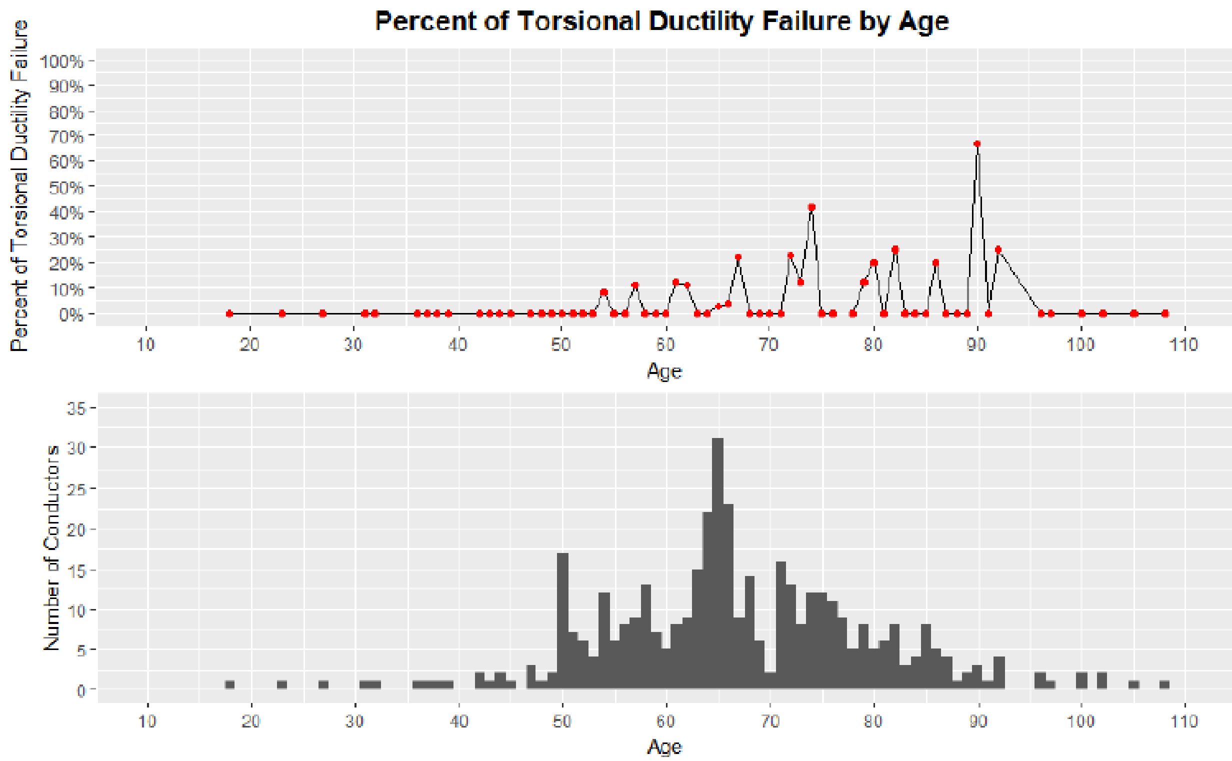


Figure 3-68
Torsional Ductility Failure (#Turns ≤ 5) by Age (All ACSR)

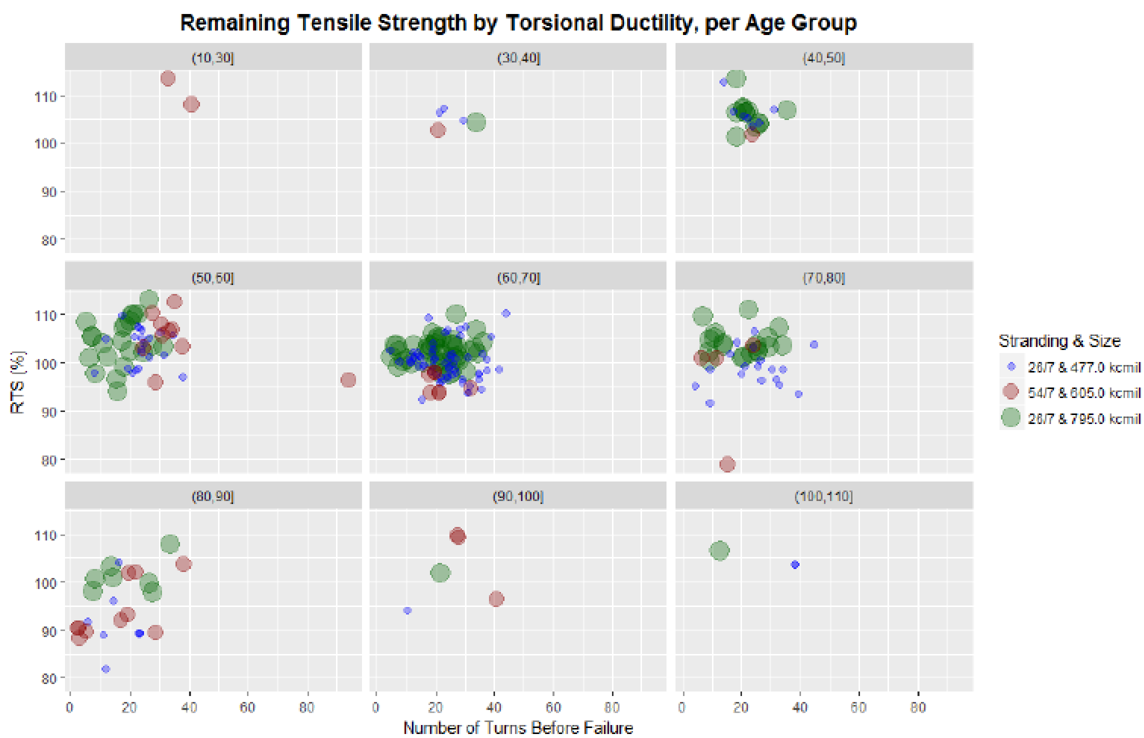


Figure 3-69
Tensile Strength by Torsional Ductility per Age Group (Three Selected Sets)

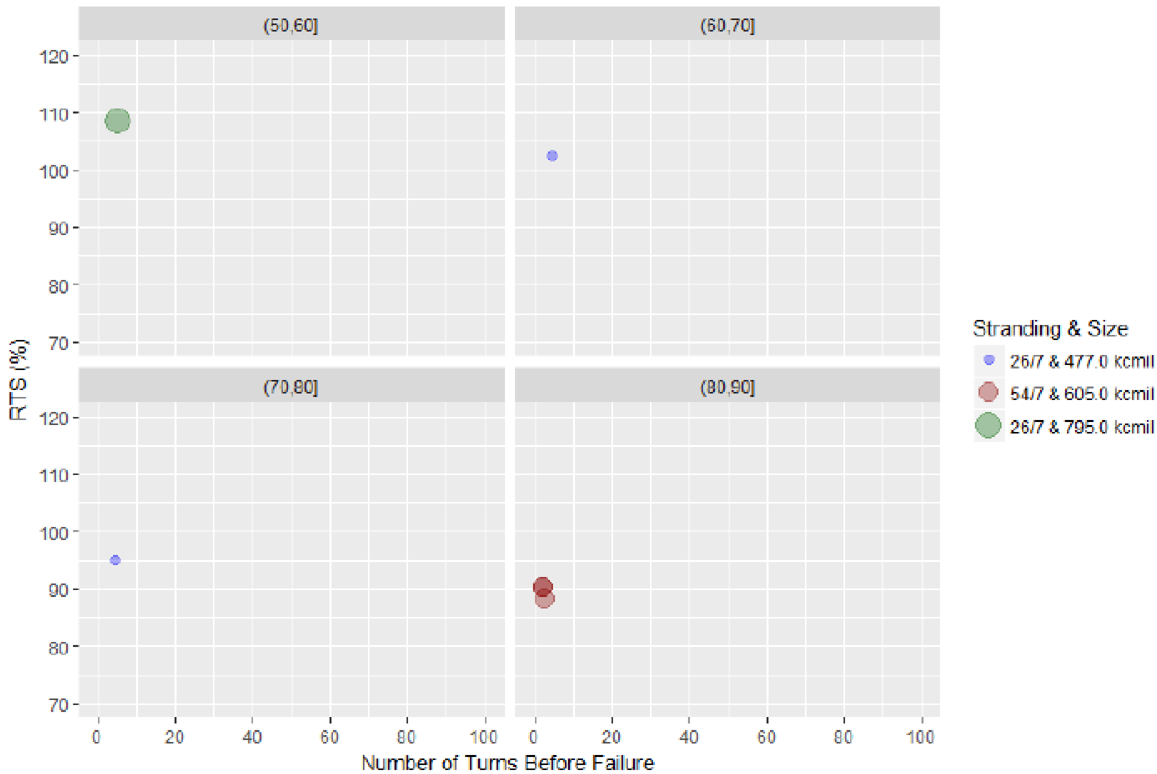


Figure 3-70
Torsional Ductility Failure (#Turns ≤ 5) by Age Group (Three Selected Sets)

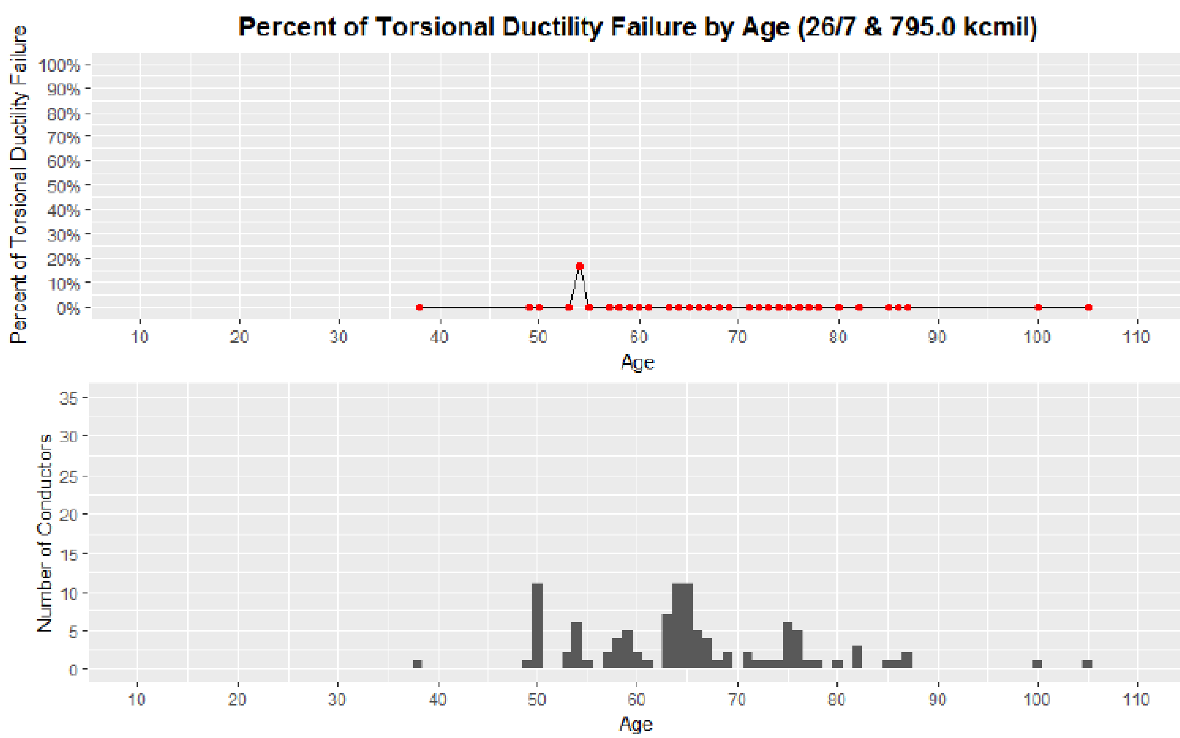


Figure 3-71
Torsional Ductility Failure (#Turns ≤ 5) by Age (26/7 & 795.0 kcmil)

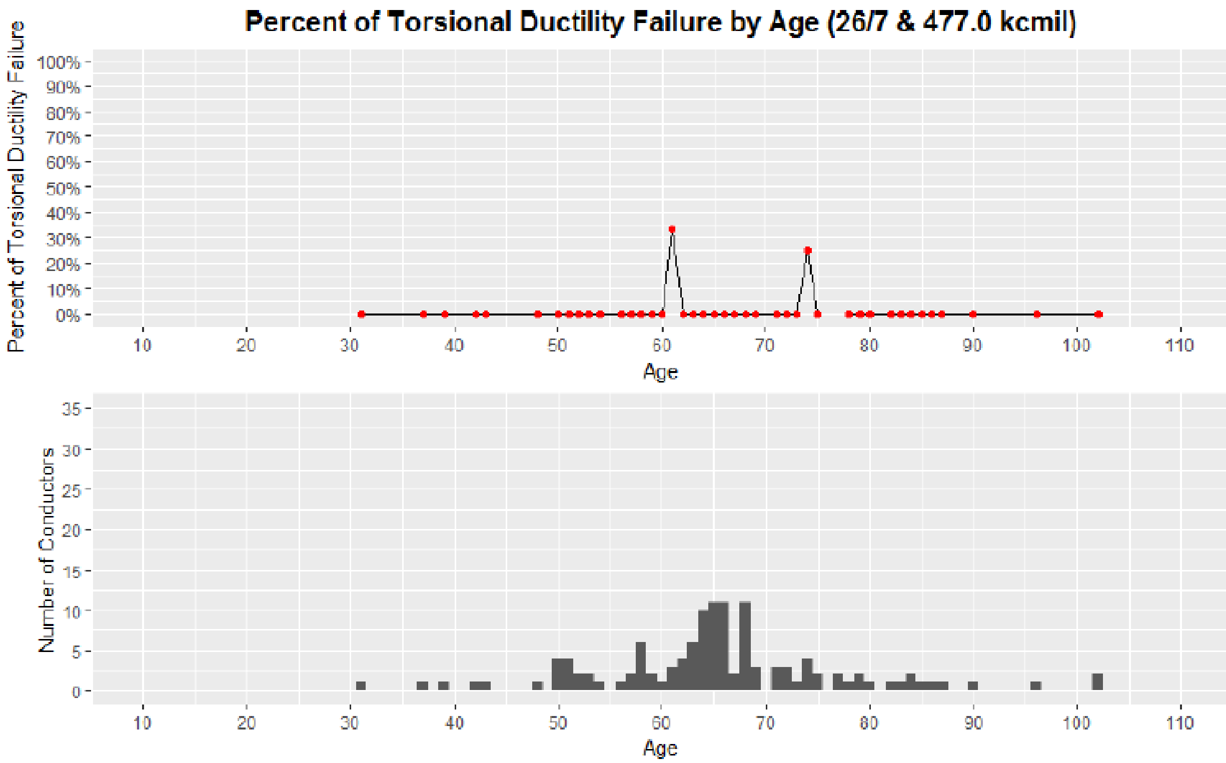


Figure 3-72
Torsional Ductility Failure (#Turns ≤ 5) by Age (26/7 & 477.0 kcmil)

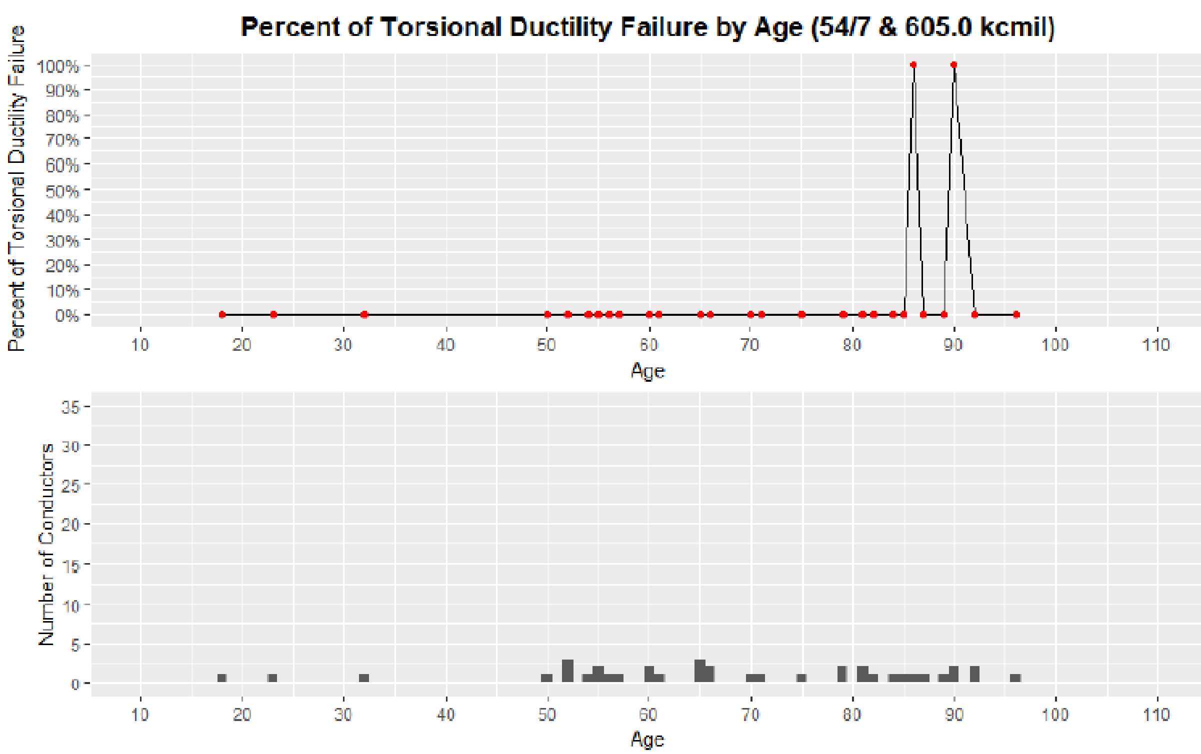


Figure 3-73
Torsional Ductility Failure (#Turns ≤ 5) by Age (54/7 & 605.0 kcmil)

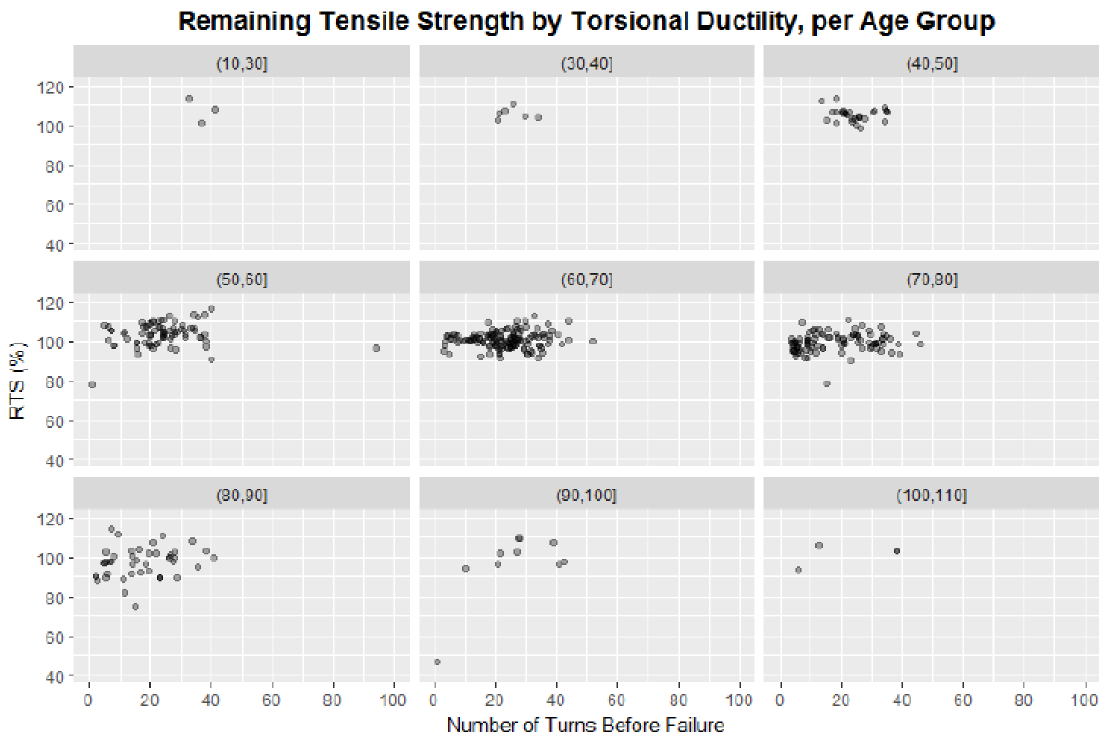


Figure 3-74
Tensile Strength by Torsional Ductility per Age Group (All ACSR)

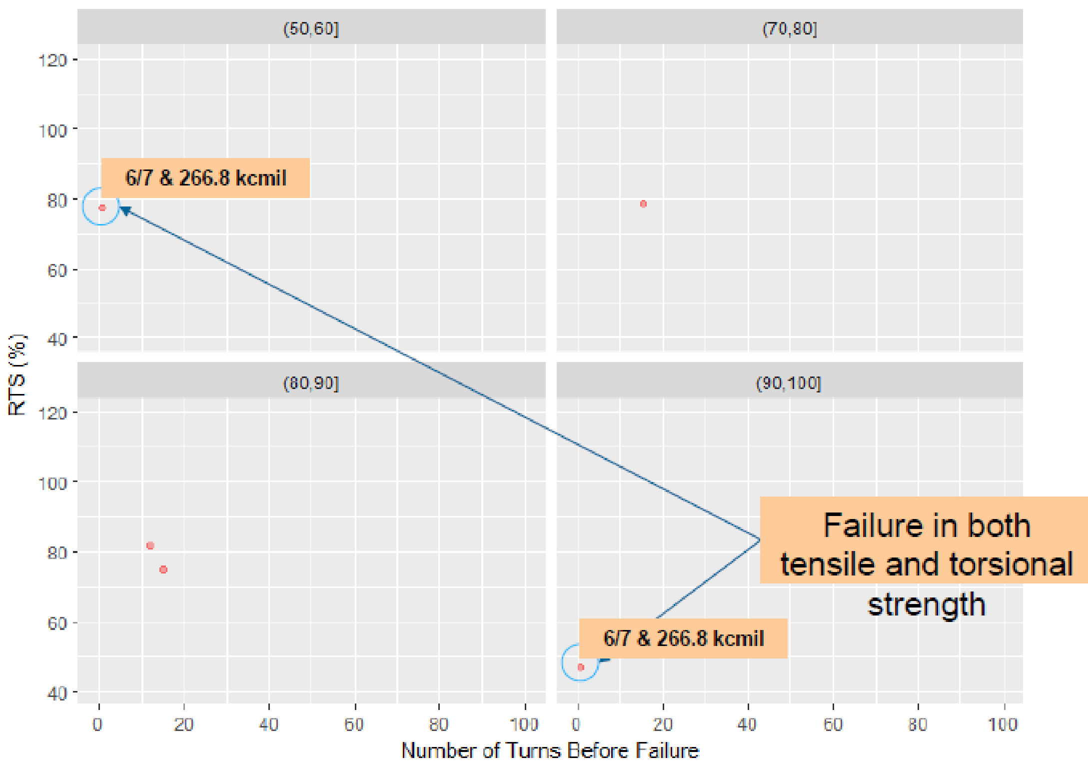


Figure 3-75
Tensile Strength Failure (RTS% ≤ 85%) by Age Group (All ACSR)

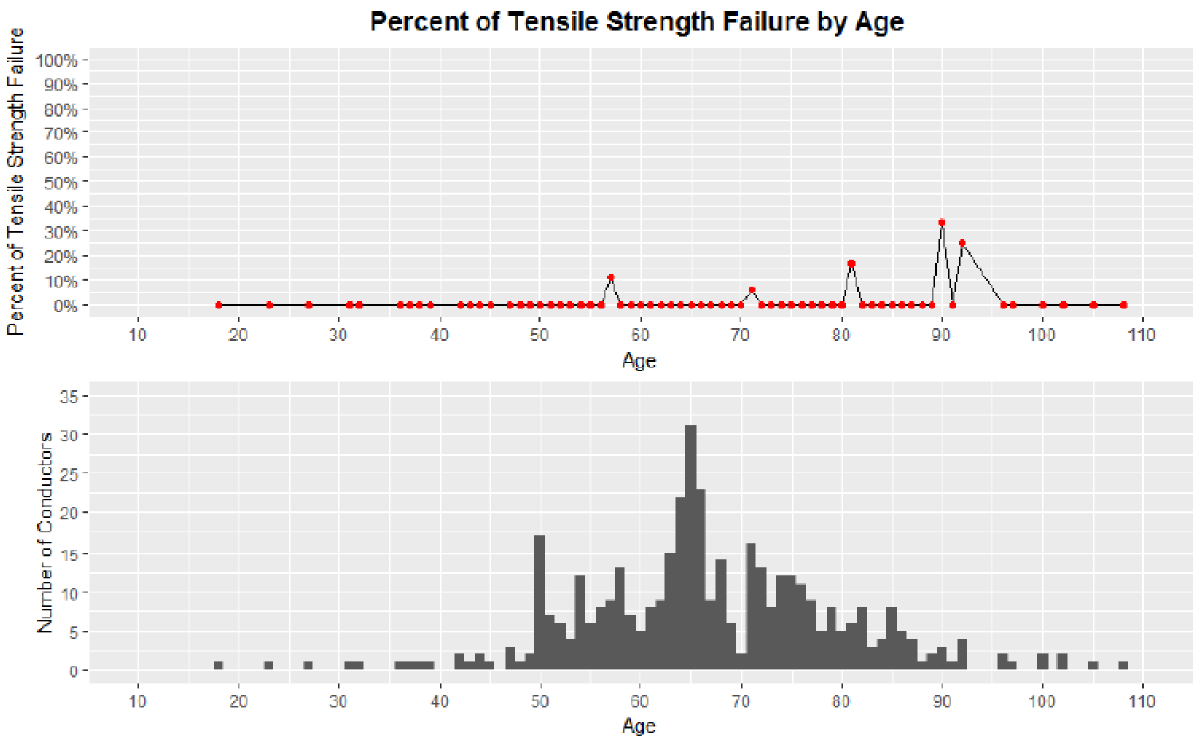


Figure 3-76
Tensile Strength Failure (RTS% ≤ 85%) by Age (All ACSR)

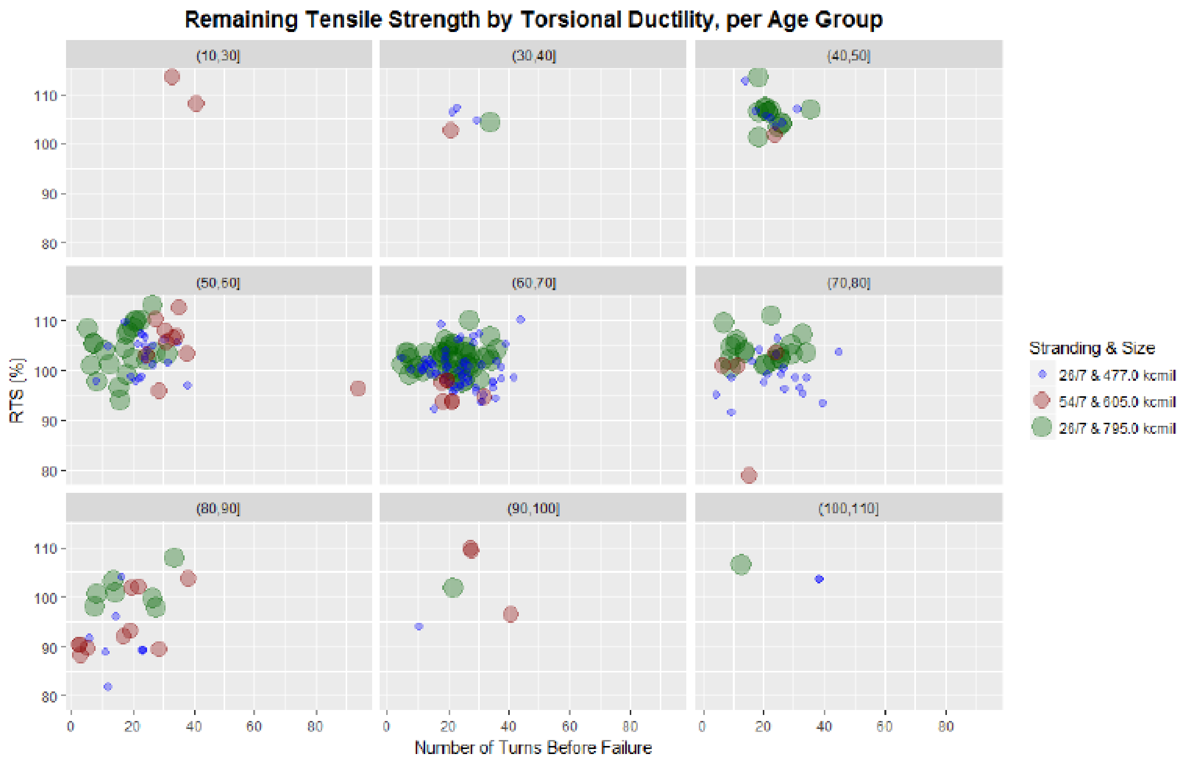


Figure 3-77
Tensile Strength by Torsional Ductility per Age Group (Three Selected Sets)

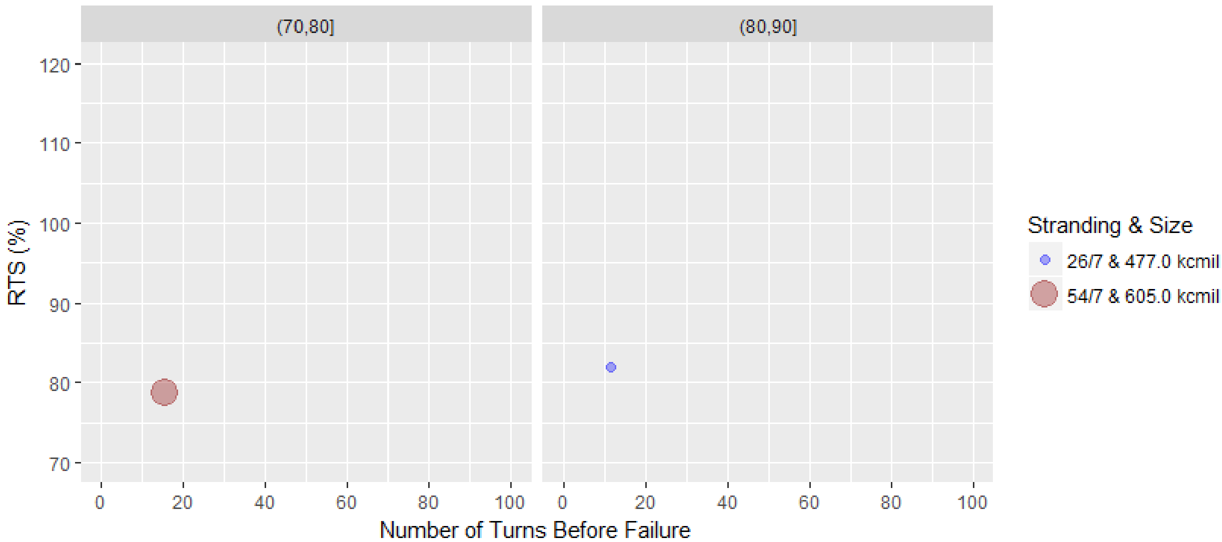


Figure 3-78
Tensile Strength Failure (RTS% ≤ 85%) by Age Group (Three Selected Sets)

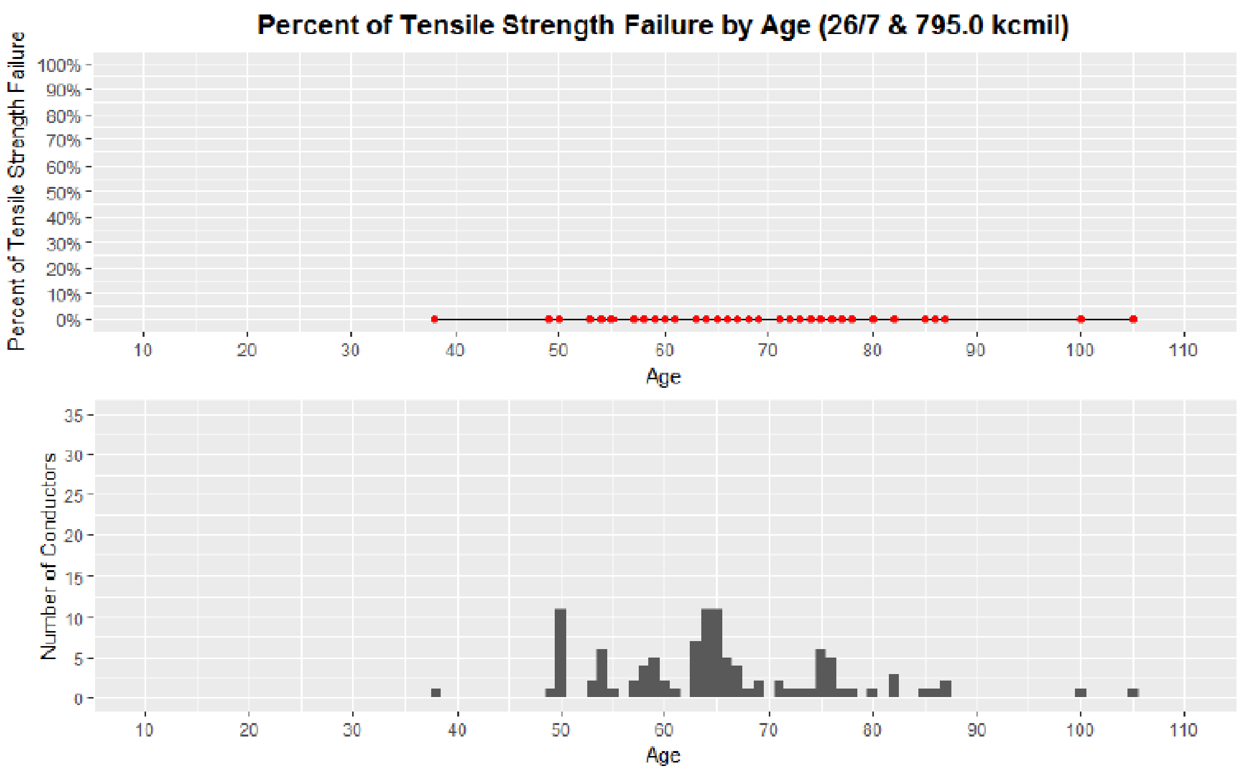


Figure 3-79
Tensile Strength Failure (RTS% ≤ 85%) by Age (26/7 & 795.0 kcmil)

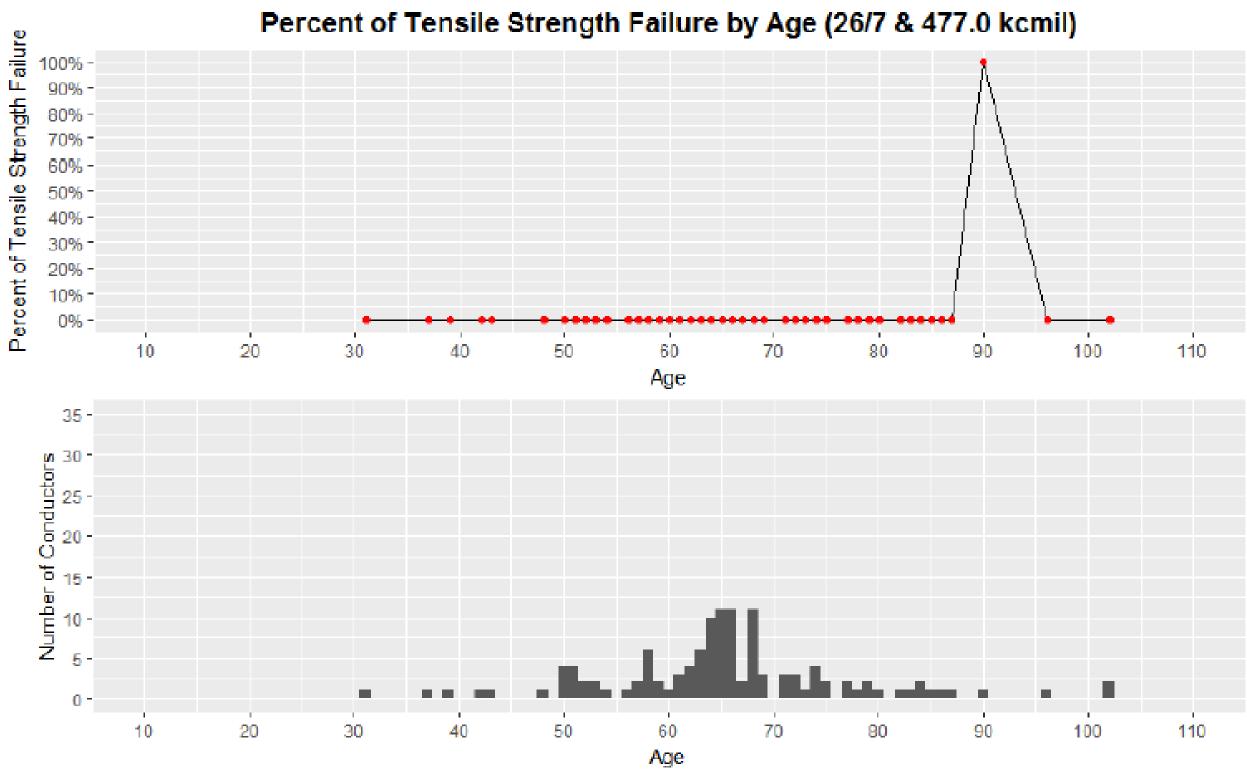


Figure 3-80
Tensile Strength Failure (RTS% ≤ 85%) by Age (26/7 & 477.0 kcmil)

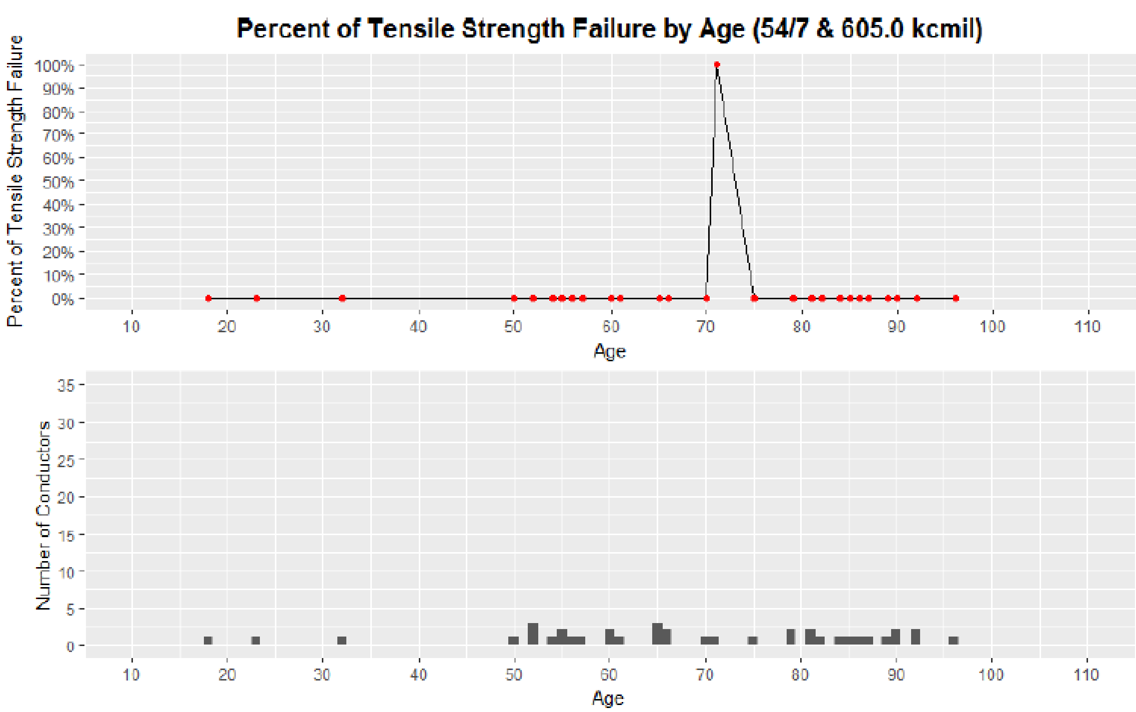


Figure 3-81
Tensile Strength Failure (RTS% ≤ 85%) by Age (54/7 & 605.0 kcmil)

The preceding figures show that when treating torsional ductility and tensile strength as dependent variables, end-of-life occurrences are too sparse to yield any meaningful age-related models for hazard functions. The same issues occurred when using smaller data sets regardless of dependent variables. This pointed researchers back to using the overall condition score as the dependent variable and treating all ACSR data as a single data set for modeling purposes. The practical result is that no age dependent progressive degradation model (i.e. one that would model the progression from condition 1 to 2, 2 to 3, etc.) could be developed.

Exploratory Analyses Conclusions

EPRI analyses confirmed the finding from the Hydro One "Conductor End of Life Study" that corrosion zone factor has no demonstrated effect on assessed degradation. Investigators set aside corrosion zone factor and treated all ACSR data as a single data set.

Investigators also found no meaningful relationships among the overall condition and its constituent conditions (assessment factors):

- Extent of Rust
- Severity of Rust
- Remaining Zinc
- Torsional Ductility
- Tensile Strength

and conductor stranding or conductor size.

However, a relationship between EOL condition and age was indicated. The following figure shows the percent of conductor samples with Overall Condition Score of 5 plotted by age, with "Long Test Reports" data included as additional EOL samples.

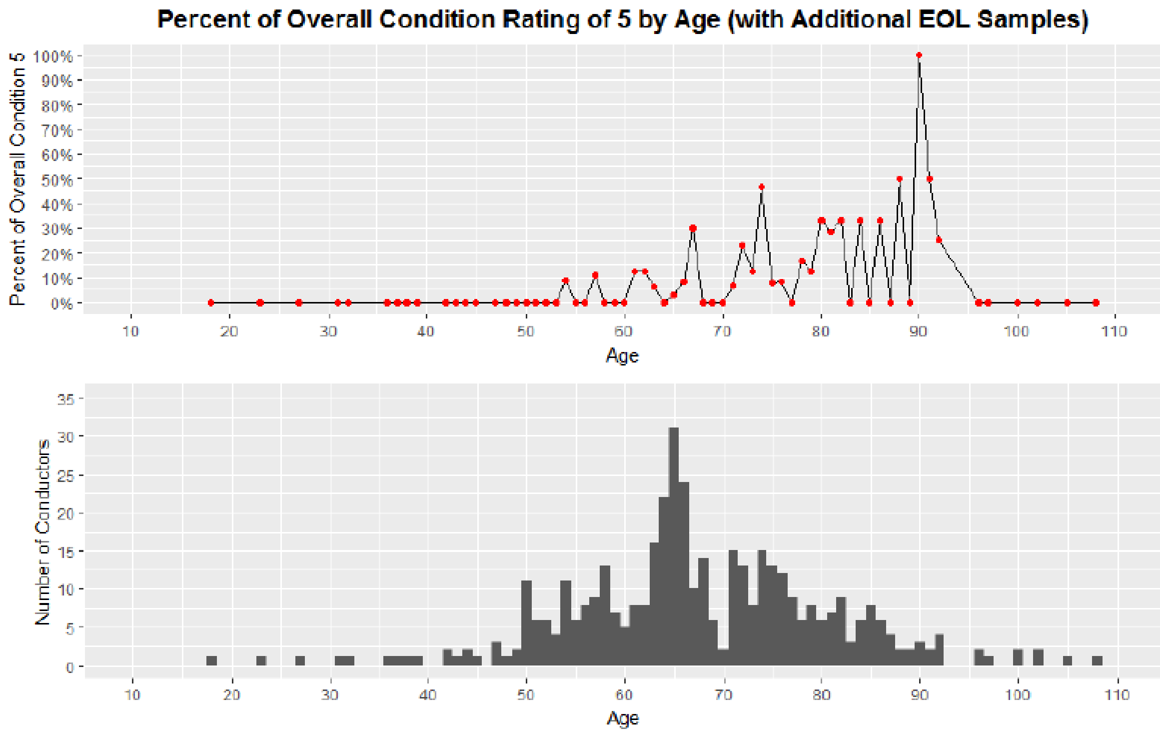


Figure 3-82
Percent of Samples with OCS Rating of 5 by Age (All ACSR)

With no success in finding a useful age dependent progressive degradation model, investigators turned to modeling the final degradation state (condition 5) as a function of age and applied EPRI's Bayesian failure analysis approach to model the assessed end-of-life condition rate as a function of age based on the provided data. A separate analysis that models end-of-life or near end of life (condition 5 or 4) as a function of age was also performed. A third analysis was conducted using in service and replacement demographic data.

4
MODELING OF ASSESSED CONDITION AS A FUNCTION OF AGE

Assessment/Replacement Time versus State Change

An important characteristic of assessment data such as that provided for Hydro One conductor condition is that the only known time is that associated with the condition measurement, not the time at which a particular condition was reached. With reference to Figure 4-1, we only know conductor condition at the time of assessment or replacement (t_1), and do not know the time of state change t_0, which most likely occurred sometime before the time of assessment or replacement (t_1).

To accommodate this characteristic, EPRI developed software to model the event of state change, i.e. reaching condition(s) requiring replacements, with known assessment or replacement times but unknown state change time (t_0).

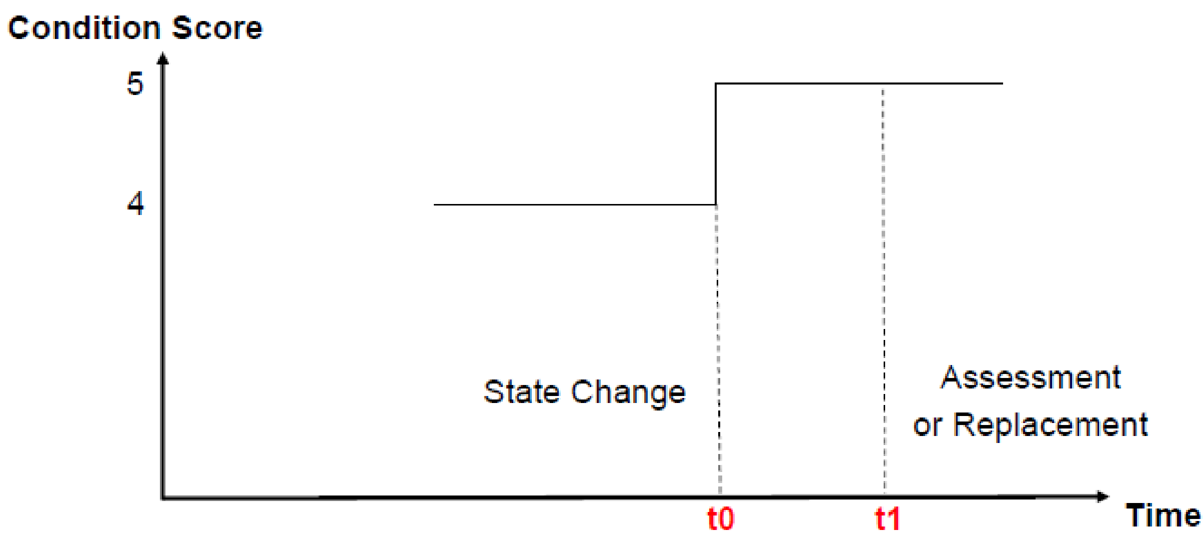


Figure 4-1
Assessment or Replacement Time versus State Change

The replacement and in-service data included line sections with widely different lengths. Consequently, all line sections (both replacement and in-service) were weighted in proportion to the corresponding line section lengths in kilometers, rounded to the nearest integer. For example, a line section with a length of 11.3 km was assigned a weight of 11, i.e. represented by 11 samples in the input data to the model. Note that line sections with section length less than 0.5 km (totaling just 0.6% of the total installed length of the entire ACSR fleet) were assigned a weight of zero and therefore excluded from analysis. With this exclusion, the weighted average age across ACSR line sections increases by less than 0.05 years. One may conclude that not including these segments of less than 0.5 km length has no material effect on the analysis.

Data Sources Summary

The three analyses performed with the provided data are shown diagrammatically in Figure 4-2.

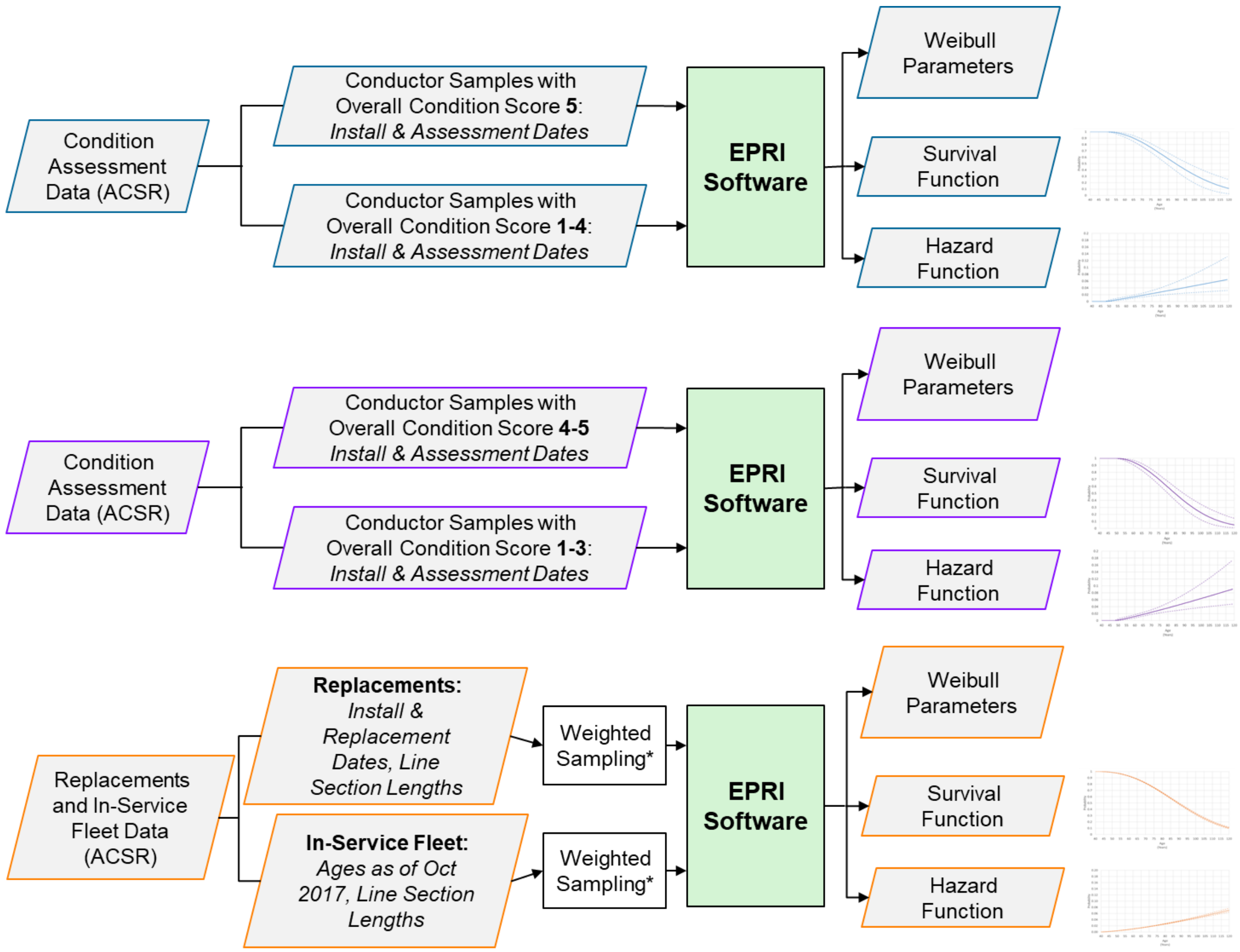
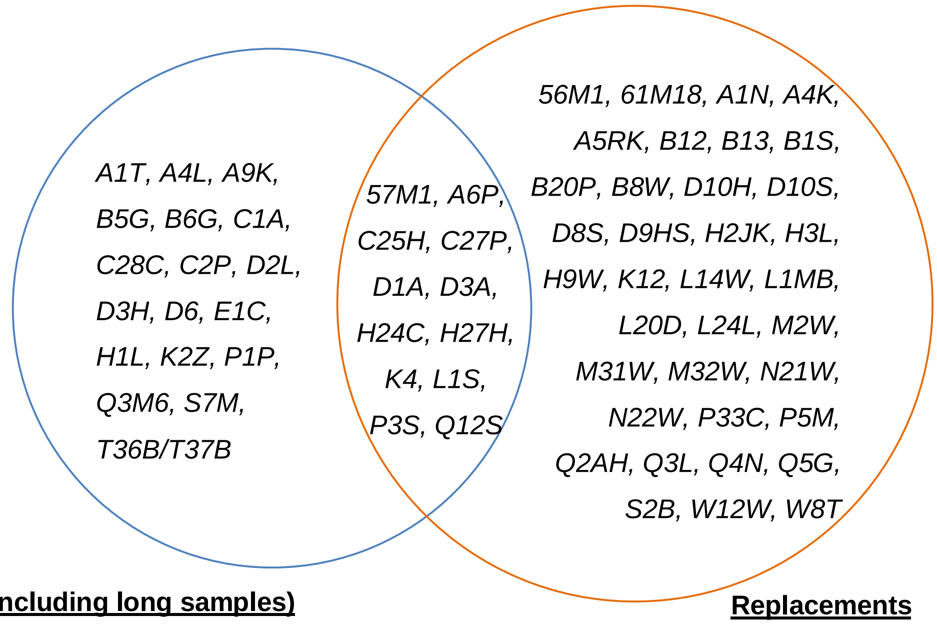


Figure 4-2
Analyses Performed

Figure 4-3 recaps the unique circuits, total number of entries, and collection periods associated with the OCS 5 data set (including long samples) and replacement records data set.



OCS 5 (including long samples)
30 circuits represented, 12 of which are shared with replacement records
(44 entries total, spanning January 2001 - December 2016)

Replacements
48 circuits represented, 12 of which are shared with OCS 5
(126 entries total, spanning January 1988 - January 2017)

Figure 4-3
Venn Diagram Showing Circuits, Number of Data Entries, and Collection Periods Associated with the OCS 5 Samples and Replacement Records Data Set, along with Their Intersections

The following table shows comparisons of the analysis results of the mean Weibull hazard function parameters and median life derived from replacement and in-service fleet data and condition assessment data. Subsequent figures show analysis results on hazard and survival functions derived from these two data sources.

Table 4-1
Weibull Hazard Model Results for the Analyses Shown in Figure 4-2

Life Event Modeled	Input Data	Mean Weibull Parameters			Median Life (years)
		Shape	Scale	Location	
Replacements	Replacement & in-service fleet data	2.46	57.4	40.0	~ 89.5
Reaching EOL condition (5)	Condition assessment data	1.71	47.0	53.0	~ 91.0
Reaching EOL condition (5) or near EOL condition (4)	Condition assessment data	2.02	33.0	46.0	~ 73.5

Note that scale parameter results for the EPRI approaches are based on Weibull distributions shifted by a corresponding location parameter. The location parameters for each model were determined by the youngest aged sample to have experienced the hazard in each cohort. Based on the provided data, EOL conditions do not occur before age 53, near EOL conditions do not occur before age 46, and replacements generally do not occur before age 40. Care should be taken when interpreting these results, e.g. for the analysis using the replacements and in-service fleet data, the model suggests 63% of the population will reach condition(s) requiring replacement by Age 97.4, (57.4 {scale} + 40.0 {location}). Values for shape and scale shown are means.

Once the Weibull function parameters are determined, other useful functions, as presented in the following figures, can be derived. In all cases, the dotted lines represent 95% confidence bands.

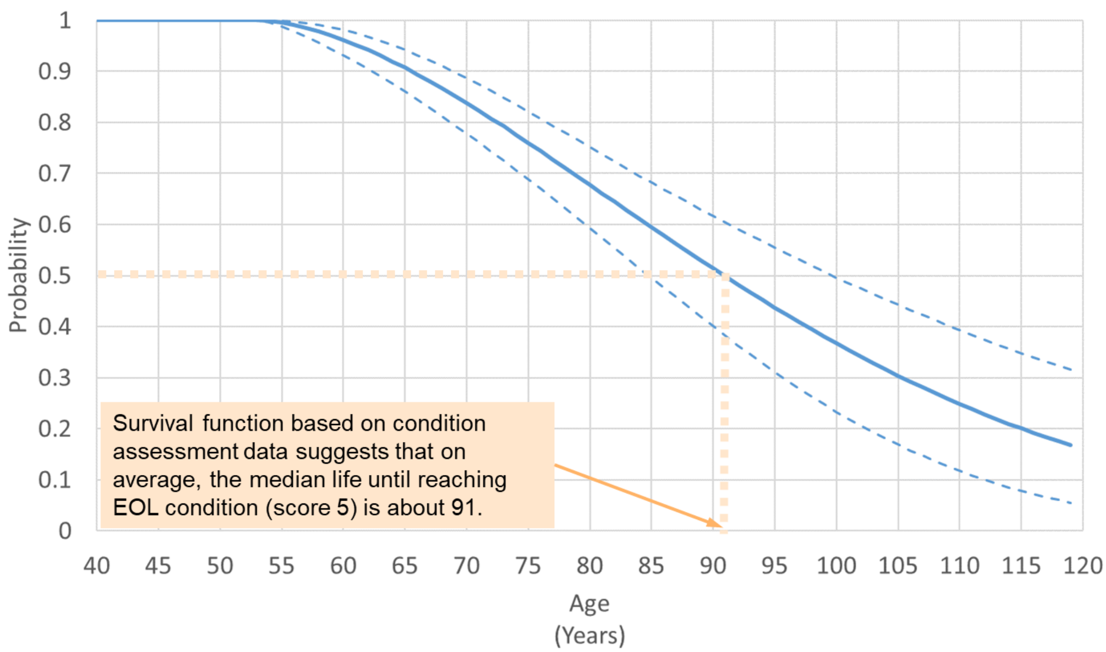


Figure 4-4
Survival Function Based on Condition Assessment Data Modeling the Event of Reaching EOL Condition (Score 5)

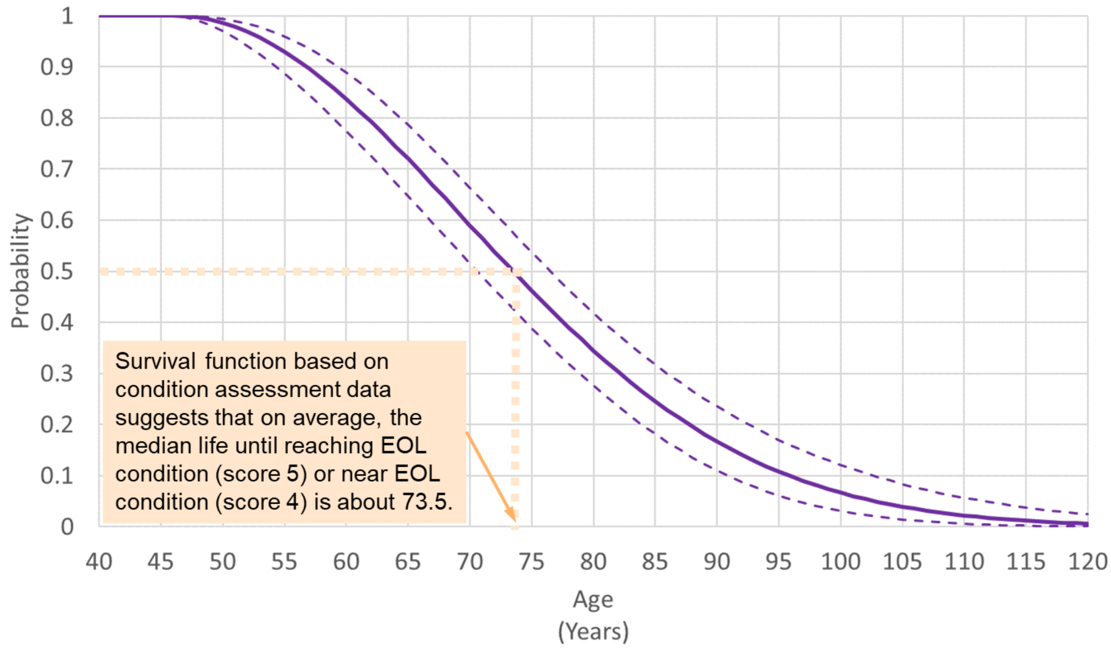


Figure 4-5
Survival Function Based on Condition Assessment Data Modeling the Event of Reaching EOL Condition (Score 5) or Near EOL Condition (Score 4)

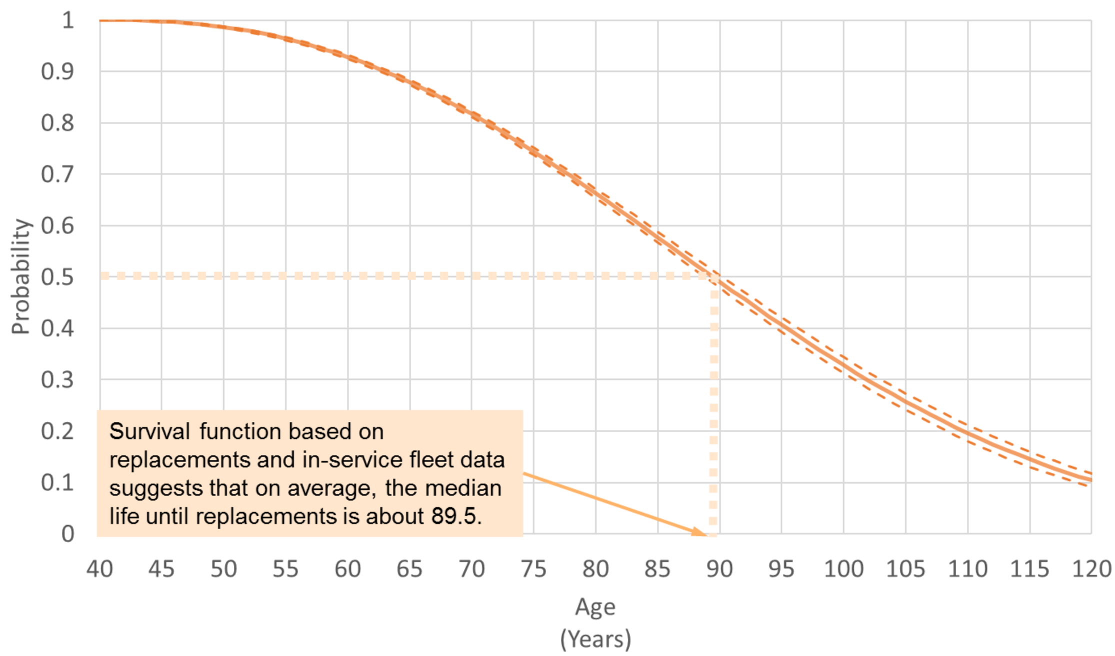


Figure 4-6
Survival Function Based on Replacements and In-Service Fleet Data (as of October 2017)

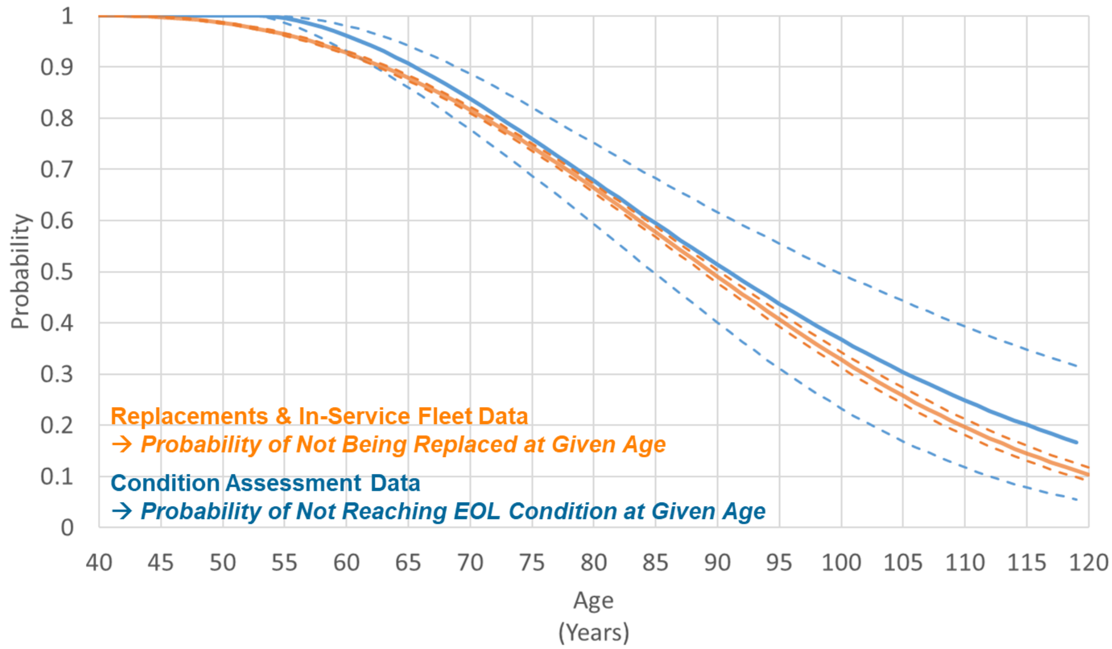


Figure 4-7
Comparison of Survival Functions Derived from Replacements and In-Service Data and Condition Assessment Data (OCS 5)

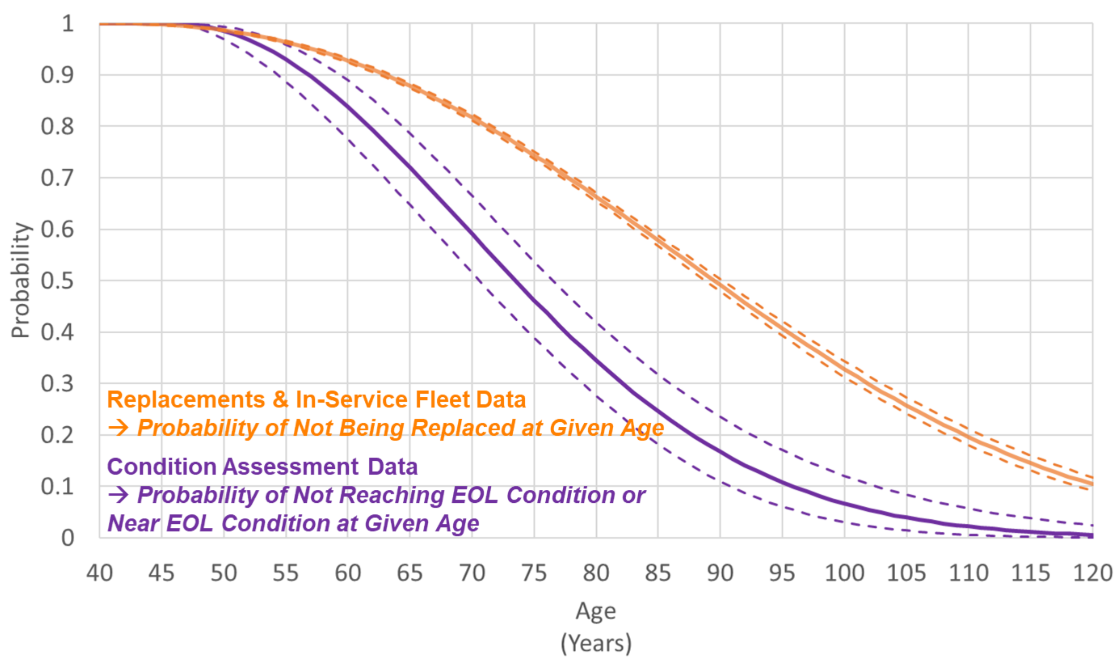


Figure 4-8
Comparison of Survival Functions Derived from Replacements and In-Service Data and Condition Assessment Data (OCS 5 or 4)

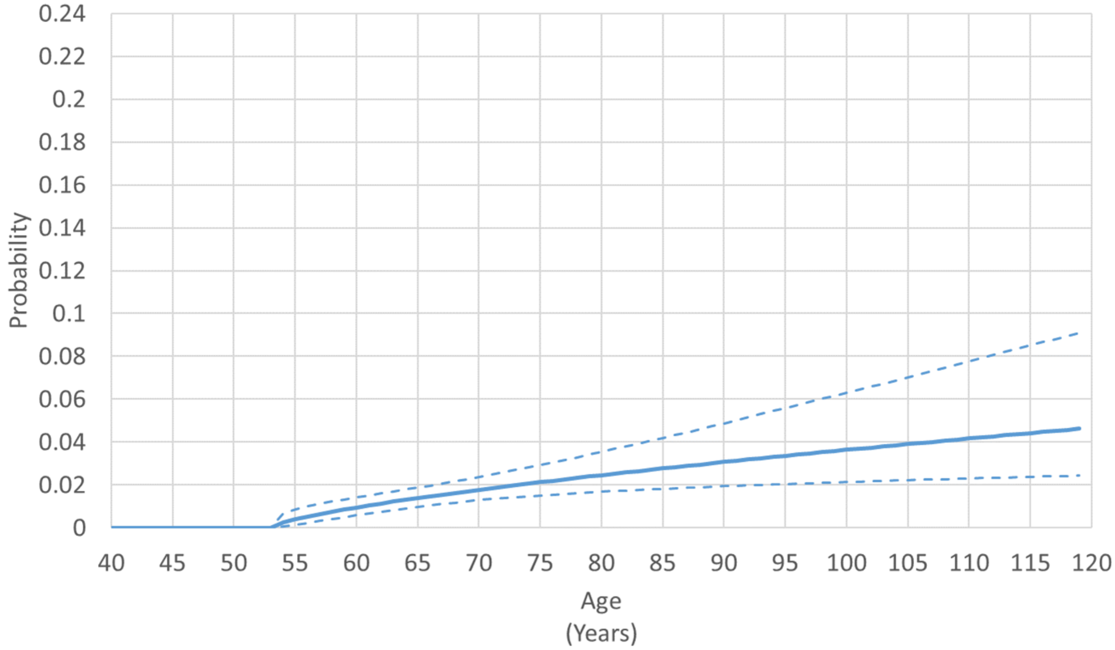


Figure 4-9
Hazard Function – Age-Dependent Probability of a Sample Reaching EOL Condition within Next Year (Based on Condition Assessment Data)

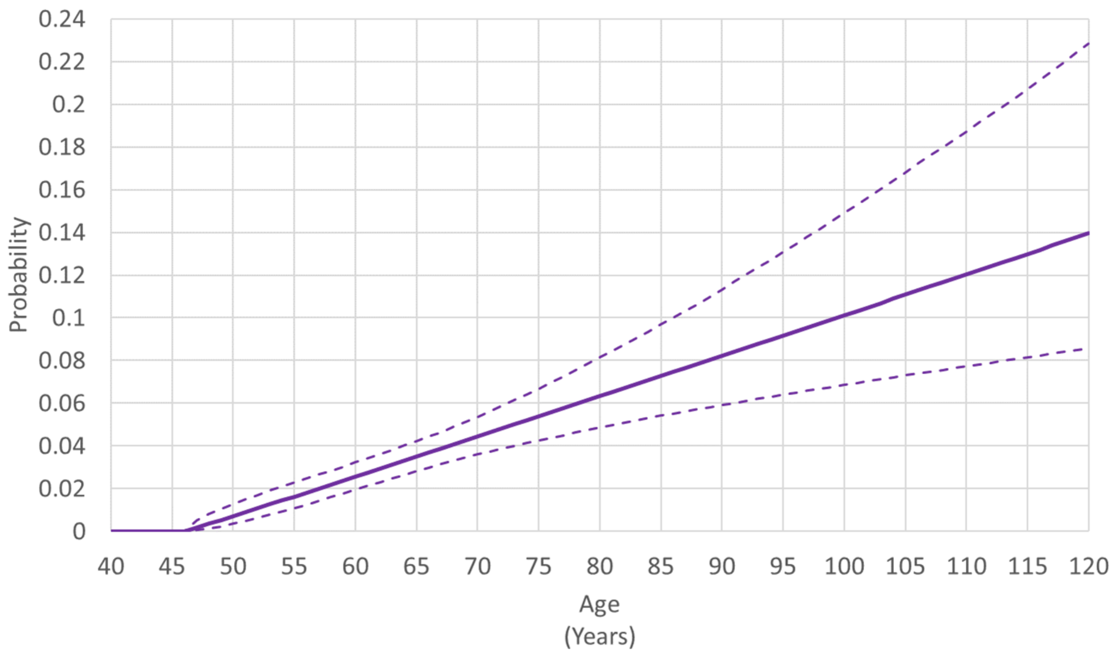


Figure 4-10
Hazard Function – Age-Dependent Probability of a Sample Reaching EOL Condition or Near EOL Condition within Next Year (Based on Condition Assessment Data)

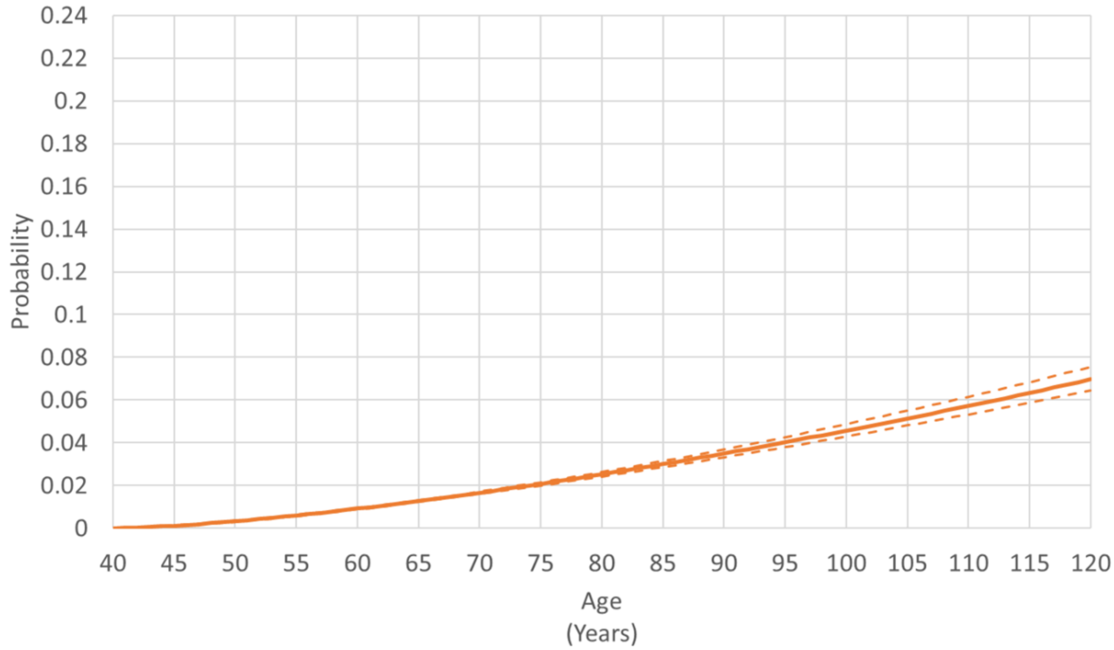


Figure 4-11
Hazard Function – Age-Dependent Probability of a Sample Reaching Condition(s) Requiring Replacement within Next Year (Based on Replacements and In-Service Fleet Data)

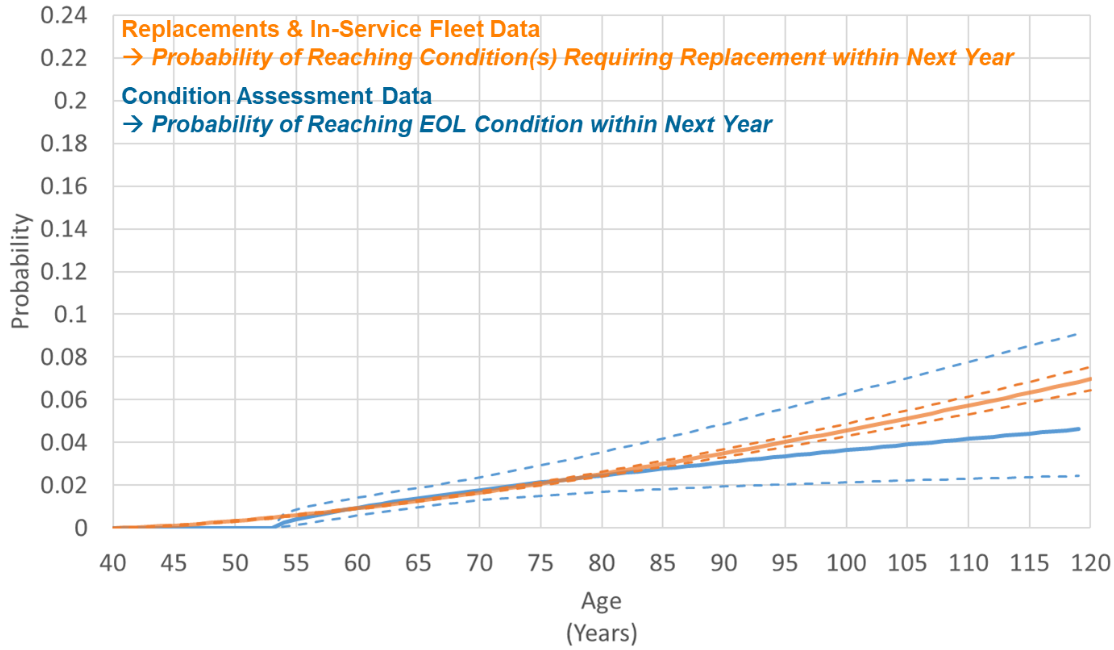


Figure 4-12
Comparison of Hazard Functions Derived from Replacements and In-Service Data and Condition Assessment Data (OCS 5)

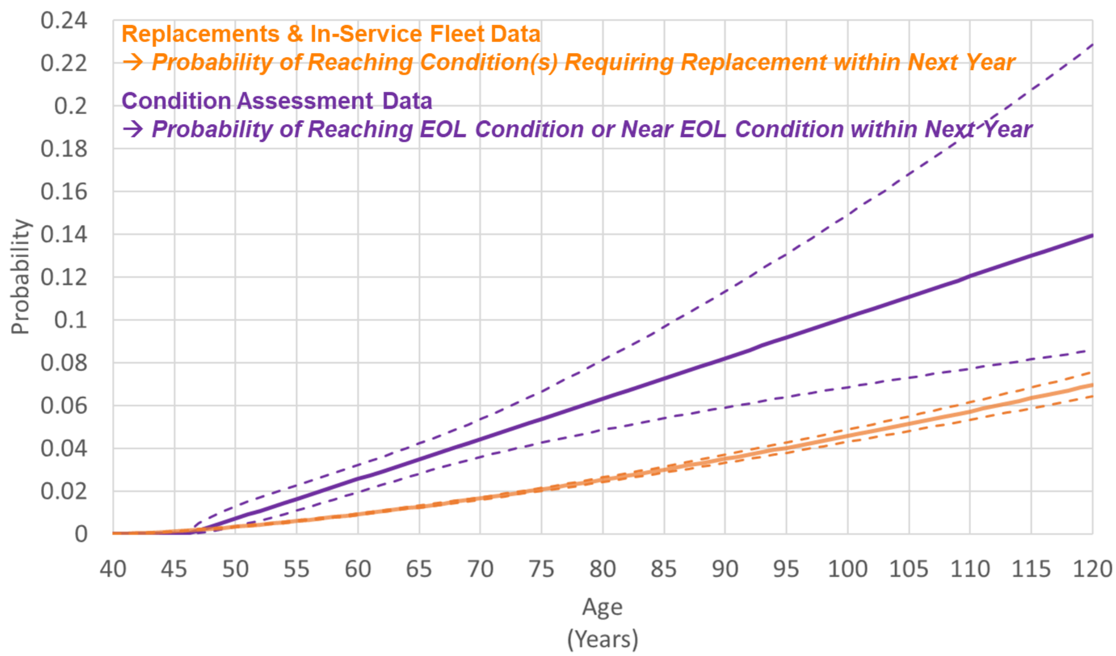


Figure 4-13
Comparison of Hazard Functions Derived from Replacements and In-Service Data and Condition Assessment Data (OCS 5 or 4)

Summary of Analysis Results

The OCS 5 and the replacement analysis results, although obtained from different data sources (condition assessment vs replacement/in-service), are in good agreement. As shown in Figure 4-3, the overlaps between the two data sources in terms of time periods and circuits represented are limited. These limited commonalities between these two data sources along with the good agreement of their results provide evidence that suggests the replacements data can be a good proxy for the condition assessment data.

5
DISCUSSION AND APPLICATIONS OF MODELING RESULTS

Comparison with Results from Hydro One 2014 Asset Failure Analysis (Foster Associates, 2014)

The Foster study provided by Hydro One included the following two sets of results:

- Iowa (non-parametric) curves
- Weibull (parametric) model

EPRI Weibull results and the Foster Iowa (non-parametric) survival curve (with a median life of about 87) are reasonably close (see Figure 5-1 for Foster Iowa survival curve).

However, the Weibull model results included in the Foster report presented a largely unrealistic scenario. As shown in Figure 5-2, the survival function derived from Foster's Weibull model suggests that conditions requiring replacement are not reached until after age of 150, and that all will have reached such conditions by age of 190 (with a median life of around 170).

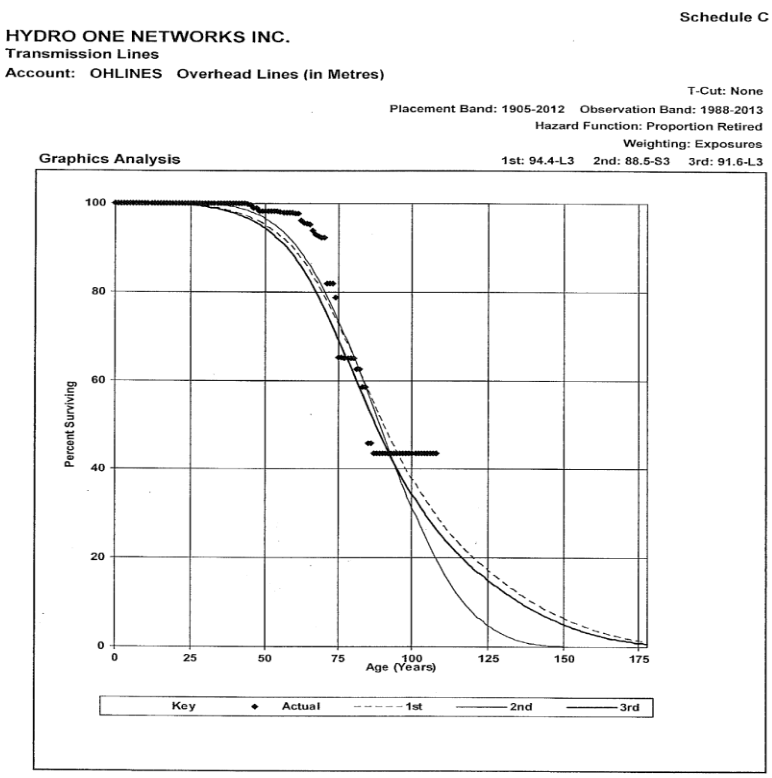


Figure 5-1
Non-parametric (Iowa) Survival Curve *Hydro One 2014 Asset Failure Analysis* (Foster Associates, 2014)

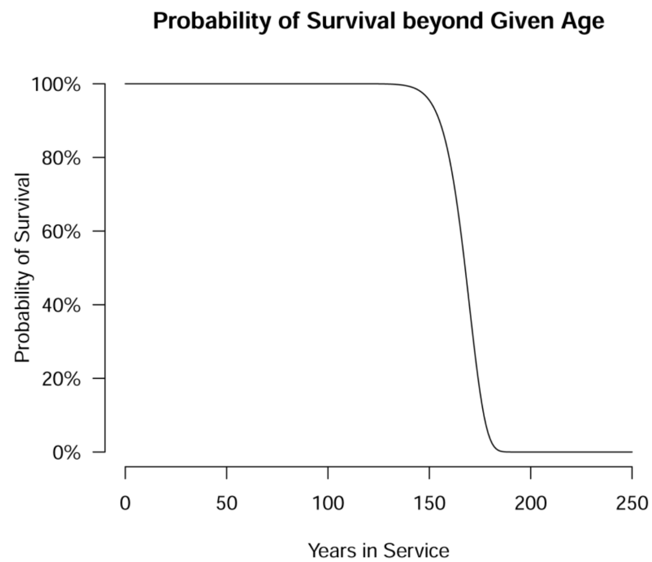


Figure 5-2
Survival Function for Weibull Model Included in Foster Report

EPRI Projected ACSR Replacements (km) within Next 1-5 Years Based on Replacements Data and Condition Assessment Data

One may convolute a given age dependent hazard rate with demographic data of an in-service fleet to develop projections of the total amount of conductor lengths that would experience the hazard. It is important to note that such projections provide estimates for the population as a whole and not information on any individual segments. These projections are forward looking estimates based on the ages of currently installed segments.

A series of projections were developed from the three EPRI Weibull models (condition assessment OCS 5, condition assessment OCS 5 or 4, and replacements) and the in-service ACSR fleet line segment ages and lengths, as shown in Figures 5-3 through 5-5. The projections provide cumulative estimates of circuit-kilometers expected to reach a condition warranting replacement (derived from replacements/in-service fleet data) or OCS 5 (derived from OCS 5 condition assessment data) by year. Projections for cumulative estimates of circuit-kilometers expected to reach OCS 5 or 4 were also included in these figures (derived from OCS 5 or 4 assessment condition data). The numbers provide the mean values and the vertical lines the 95% confidence bands. Each set of projections were calculated by convoluting installed lengths by age (the in-service fleet) and age dependent replacement rates derived from the corresponding EPRI Weibull model.

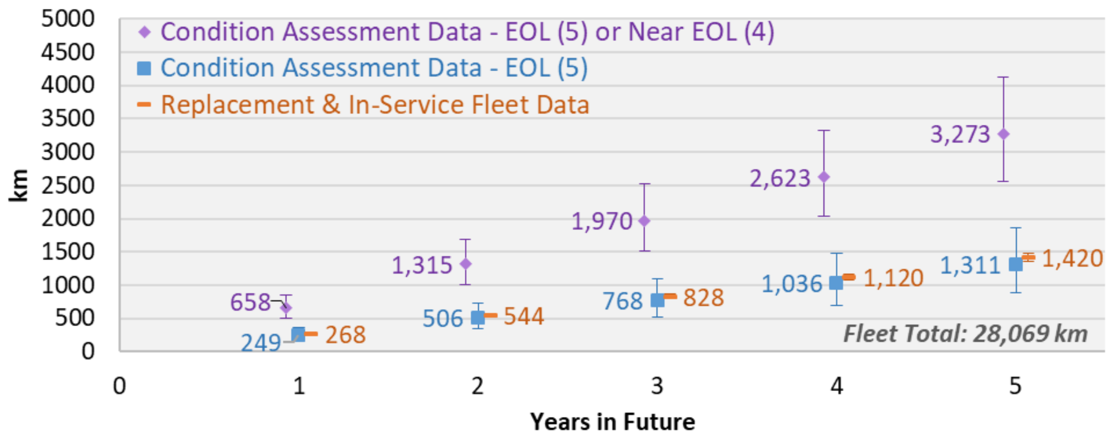


Figure 5-3
EPRI Cumulative Estimates of ACSR Circuit-km Expected to Reach a Condition Requiring Replacement, OCS 5, or OCS 5 or 4 within Next 1-5 Years Based on Replacements Data and Condition Assessment Data

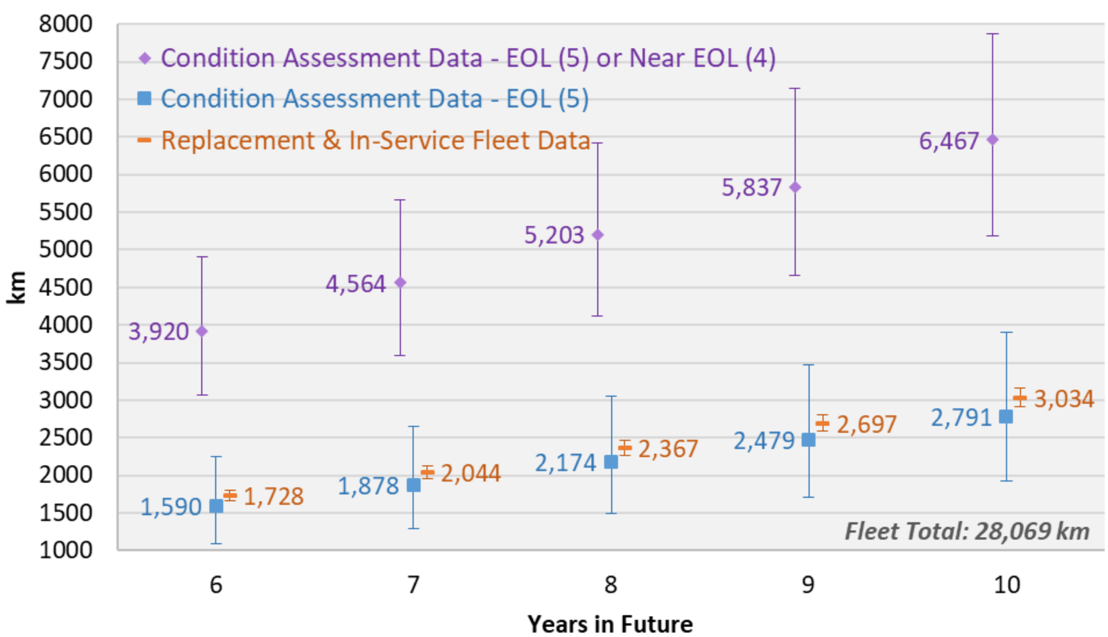


Figure 5-4
EPRI Cumulative Estimates of ACSR Circuit-km Expected to Reach a Condition Requiring Replacement, OCS 5, or OCS 5 or 4 within Next 6-10 Years Based on Replacements Data and Condition Assessment Data

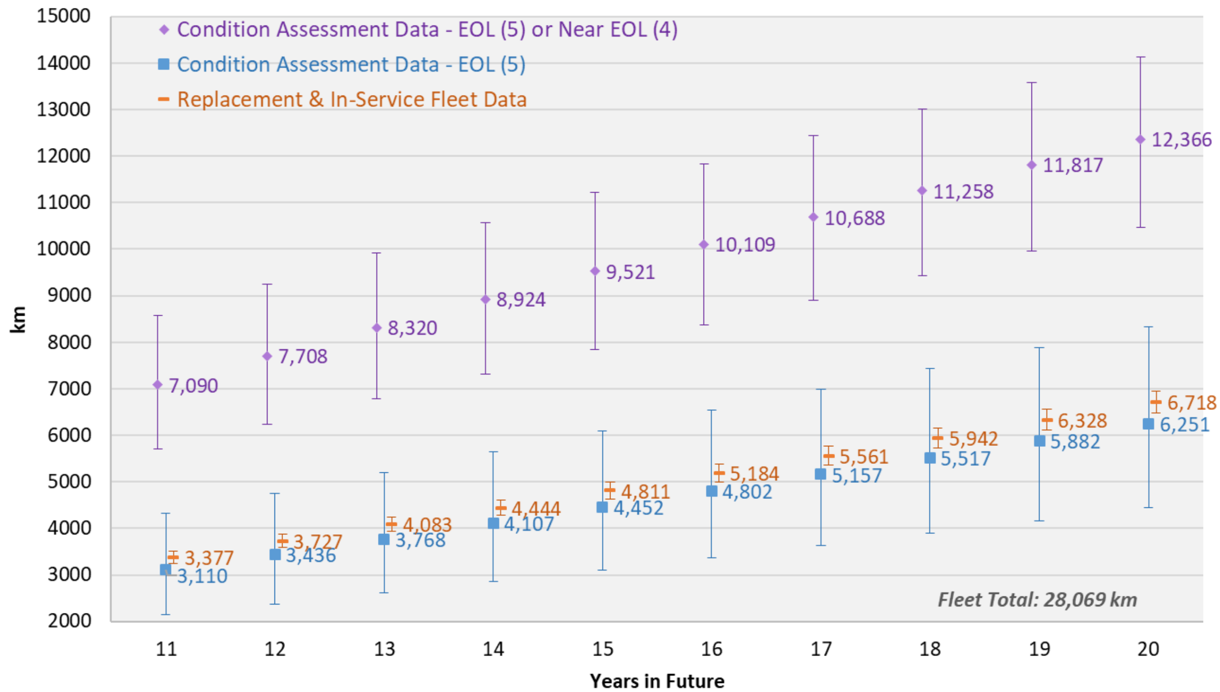


Figure 5-5
EPRI Cumulative Estimates of ACSR Circuit-km Expected to Reach a Condition Requiring Replacement, OCS 5, or OCS 5 or 4 within Next 11-20 Years Based on Replacements Data and Condition Assessment Data

Table 5-1 provides mean values (with 95% confidence bands) for the 5, 10, and 20 year projections associated with the different data sources and life events modeled.

Table 5-1
EPRI Cumulative Estimates of ACSR Circuit-km Expected to Reach a Condition Requiring Replacement, OCS 5, or OCS 5 or 4 within Next 5, 10, and 20 Years

Life Event Modeled	Input Data	Projection Means (and 95% Confidence Bands) in km		
		5 Years	10 Years	20 Years
Replacements	Replacement & in-service fleet data	1,420 (1,362, 1,481)	3,034 (2,915, 3,156)	6,718 (6,486, 6,952)
Reaching EOL condition (5)	Condition assessment data	1,311 (892, 1,863)	2,791 (1,922, 3,899)	6,251 (4,439, 8,340)
Reaching EOL condition (5) or near EOL condition (4)	Condition assessment data	3,273 (2,552, 4,123)	6,467 (5,182, 7,867)	12,366 (10,468, 14,134)

General Discussion

The conductor Condition Assessment (Score) data used are not from random samples.

For the replacements data, it is unclear whether all replacements were due to failures or lines reaching condition(s) that warrant replacements or some other reasons. Analysis results from such data can potentially be pessimistic. However, the similarity between results based on condition assessment data and results based on replacements data lead one to believe that such a concern is not necessarily warranted, especially when the commonalities between the two data sources in terms of time periods and circuits represented are limited (as discussed previously and shown in Figure 4-3).

6
CONCLUSIONS

No useful correlation was found relating conductor condition assessments to the various measured assessment factor parameters. The result was that no age-dependent progressive degradation model (i.e. one that would model the progression from condition 1 to 2, 2 to 3, etc.) could be developed. With no success in finding a useful progressive degradation model, investigators turned to modeling only the final degradation state (condition 5) as a function of age and applied EPRI's Bayesian failure analysis approach to model the assessed end-of-life condition rate pattern based on the provided data.

The good agreement between the two EPRI Weibull models derived from "failed" condition assessment data and historical replacements suggests that these models provide a fairly accurate description of past conductor performance as a function of age. The model validity is further strengthened with the general agreement with the Foster non-parametric analysis results. It is important to note that these models are probabilistic descriptions of populations. With reference to Figure 4-4, the ACSR conductor fleet mean age for reaching the EOL condition (OCS 5) is about 91 years.

Unless there is some dramatic change in the stressors leading to degradation (e.g. loading), it is reasonable to expect future performance to continue to fit these age-related models. Combining these age-dependent hazard rate models with the ages of the in-service conductor lengths can provide an estimate of the conductor lengths that would reach a condition warranting replacement (based on historical criteria) in future years. These are population-based results and provide guidance for fleet decisions.

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3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

Operating Spare Transformers Requirement Assessment

Operating Spare Transformers Requirement Assessment

Technical Update, March 2018

EPRI Project Manager
B. Desai

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THE FOLLOWING ORGANIZATION(S), UNDER CONTRACT TO EPRI, PREPARED THIS REPORT:

Electric Power Research Institute

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Electric Power Research Institute (EPRI)
1300 West W.T. Harris Blvd.
Charlotte, NC 28262

Principal Investigators
J. Bolano
B. Desai

Coplanar Consulting, LLC
893 Princess Drive
Yardley, PA 19067

Principal Investigator
M. Lebow

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EXECUTIVE SUMMARY

This report describes the application of EPRI's prototype analytics-based approach to developing optimized substation transformer spares practices for Hydro One Networks Inc.

An effective spares management strategy is an essential component of risk-based fleet management programs that enable utilities to maintain reliability in a cost-effective manner. There are significant costs associated with spares inventories including capital, storage, and, for some equipment, maintenance and testing. These costs and the potential benefits from spares are a function of the number of individual spares kept at hand. Keeping too few spares may prolong outages while too many spares would increase capital and operating costs. However, there are no industry standards or guidelines to help utilities optimize the number or mix of spares.

EPRI collaborated with Hydro One to apply its spares prototype strategy assessment analytics to Hydro One's transformer fleet. Hydro One provided data on transformer groups (e.g., 250 MVA 230/115 kV, 125 MVA 230/115 kV) and assumptions required for the simulation, for example, lead time to order a new spare, minimum threshold time for counting an unavailable transformer position.

The analysis results are provided from two perspectives:

- What is the probability that the system is not at full availability at any time?
- What is the probability that all positions are available for all days?

Keywords

Substations
Spares Strategies
Analytics
Transformers

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1
INTRODUCTION

This report describes the application of EPRI's prototype implementation of an analytics-based approach to developing optimized substation transformer spares practices for Hydro One Networks Inc.

An effective spares management strategy is an essential component of risk-based fleet management programs that enable utilities to maintain reliability in a cost-effective manner.

Background

All utilities maintain inventories of spare substation equipment to mitigate the effects of equipment failures. Without available spares, replacement times may be extended by procurement and delivery delays. In particular, substation transformers may take months to replace, potentially prolonging outages and creating significant challenges for utilities striving to maintain reliability and control capital and operating costs.

There are significant costs associated with spares inventories including capital, storage, and, for some equipment, maintenance and testing. These costs and the potential benefits from spares are a function of the number of individual spares kept. Keeping too few spares may prolong outages while too many spares would increase capital and operating costs. However, there are no industry standards or guidelines to help utilities optimize the number or mix of spares.

Approach

EPRI is developing an analytics-based approach and model to help optimize power transformer spares practices. The development of the risk based methodology for determining and evaluating spares strategies was guided by the following requirements:

- Not dependent on arbitrary assumptions
- Able to use the best available data
- Be flexible to accommodate changing needs
- Provide a system perspective
- Present probability distributions of performance metrics
- Employ risk based metrics

EPRI collaborated with Hydro One to apply the prototype implementation of its approach to Hydro One's transformer fleet. Hydro One provided data on transformer groups (e.g., 250 MVA 230/115 kV, 125 MVA 230/115 kV) and assumptions required for the simulation, for example, lead time to order a new spare, minimum threshold time for counting an unavailable transformer position.

Results

The analysis results are provided from two perspectives:

- What is the probability that the system is not at full availability at any time?
- What is the probability that all positions are available for all days?

Report Organization

This report is organized as follows:

Chapter 1: Introduction

Chapter 2: Spares Strategy Analytics and Modeling

Chapter 3: Spares Requirements Assessment Results

Chapter 4: Summary and Discussion of Results

2
SPARES STRATEGY ANALYTICS AND MODELING

Introduction

This chapter explains EPRI's approach to spares strategy analytics including proposed modeling and analytical methodologies, and presents example applications. The strategy incorporates a prototype software tool to enable users to evaluate the optimal number of spares needed to maintain a given degree of availability with a specific level of risk. The spares strategy analytics described here focuses on transformers, but it is applicable to other substation equipment as well. Additional equipment may be addressed as the analytics evolve.

The EPRI tool can be used to address the following set of decisions associated with the purchase and utilization of equipment spares:

- Demand estimation—how many spares do I need?
- Replacement planning—when do I add to the spares inventory?
- Procurement process—lead times, how many do I order, when?
- Inventory management—where do I keep them?

The strategy also considers

- Transportation from storage depot to substation site

The Big Picture

The adverse effects of transformer failures are a function of the *failure location and the time to replacement*. Thefirststepindevelopinganeffectivesparesstrategyinvolvesunderstandingthebasic elements that the strategy must address.

Evaluating an effective substation spares strategy for transformers encompasses and models the following elements:

- Substations with multiple positions for transformers
  - Attributes or characteristics associated with each substation, each transformer position, and each transformer
- Depots or repositories storing spare transformers
  - Attributes of each depot (such as types of transformers in storage)
- Time required to replace a transformer (i.e., to fill an unfilled transformer position with an operating transformer from a depot)
- Risk based on the length of time a transformer position is left unfilled

The key concept of the EPRI analytical approach is that the risks associated with the length of time a transformer position is left unfilled should be the metric for evaluating spares strategies.

To establish these risks as probabilities, in addition to the above inputs, transformer failure rates are required. Failure rates reflect the probability of failure, and can be calculated from utility historical records or based on data from the EPRI Industry-wide Transformer Database (IDB) to develop the probabilistic risk-based strategy for spares management.

This analytical methodology is intended to enable utility users to make informed decisions regarding spares that consider the risk sand, eventually, costs of different approaches.

Figure2-1isa simplified “big picture” representation of the modeling inputs. Table 2-1 shows the key attributes associated with substations, positions, and transformers.

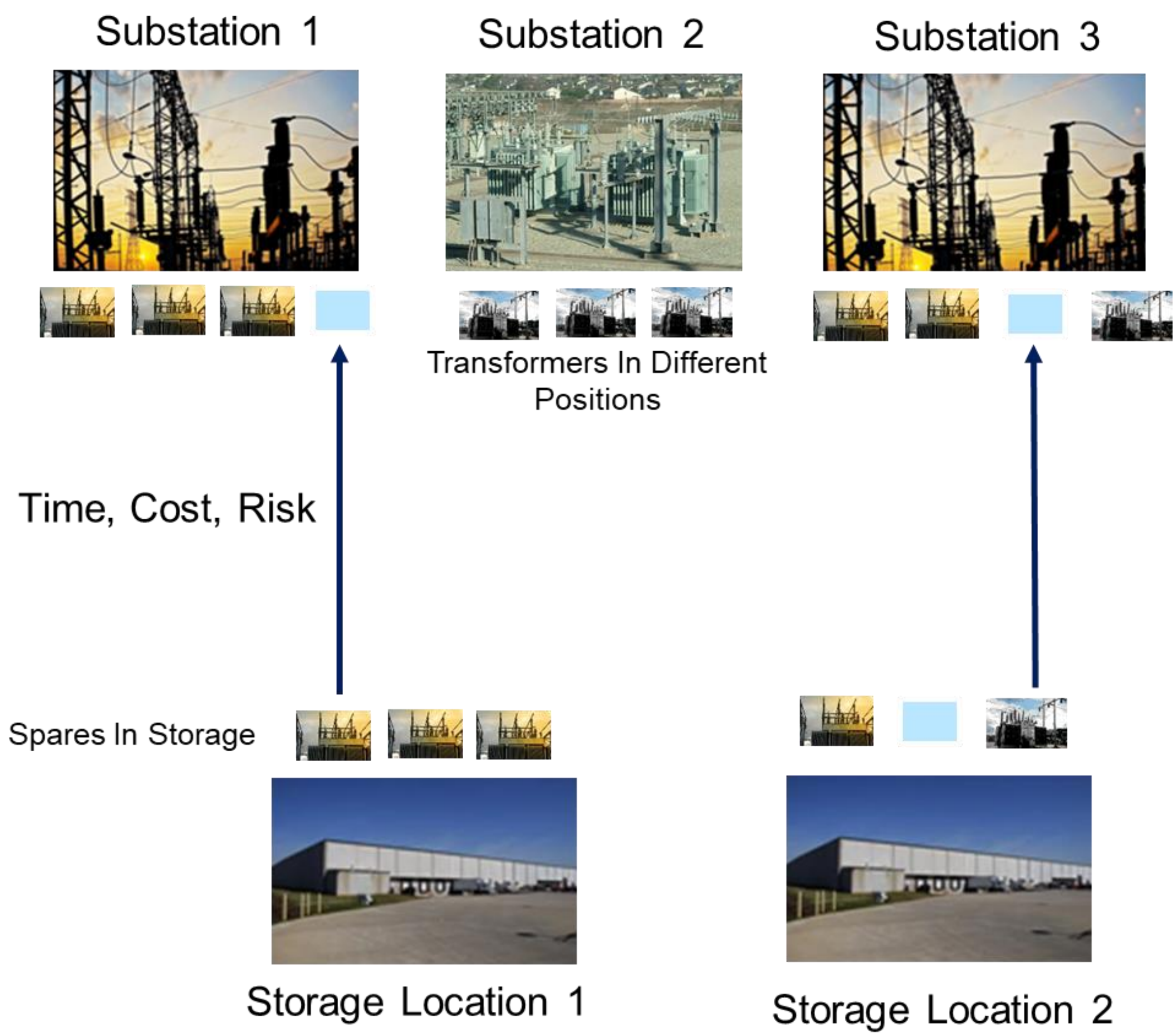


Figure 2-1
Elements of a Spares Strategy

Transformer Position

As shown in Figure 2-1, substations, transformer position, transformers, storage depots and their attributes are key modeling inputs. The most basic input is ***transformer position***, whose attributes determine the type of spare transformer that is needed and the degree of risk associated with leaving the position unfilled. It is important to understand the distinction between a transformer position and a transformer. The transformer position may be compared to a light socket whose attributes (wattage, lighting application) determine the type of bulb it can accommodate. In this analogy, a transformer may be compared to the bulb.

Nested Attributes

The model inputs form a hierarchy of nested attributes, as presented in the following table.

Table 2-1
Attributes

Station Attribute	Position Attribute	Transformer Attribute
Utility ID	Region	Serial Number
Region	Substation	Region
Design Redundancy	Utility ID	Substation
Distance from Depot 1	Voltage Class	Position
Distance from Depot 2	HV	Voltage Class
Criticality Ranking	LV1	HV
Number of Positions by transformer attribute	LV2	LV1
	Tertiary	LV2
	Auto	Tertiary
	Number of Phases	Auto (Y/N)
	LTC	Number of Phases
	NLTC	Connection Type
	Top MVA	LTC (Y/N)
	Impedance	NLTC (Y/N)
	Circuit Criticality	Top MVA
	Installation Time	Impedance
	Circuit Connection	Manufacture Date
	Physical Dimensions	Install Date
		Manufacturer
		Weight Filled
		Oil Capacity
		Availability

Spares Strategy Modeling Approach

The modeling approach uses a chronological Monte Carlo simulation utilizing non-exponential (not constant) times for equipment failure rates. Additional characteristics such as time correlation or physical constraints can be included. This approach allows for the calculation of probability distributions of the calculated indices.

A thorough review of computational techniques for statistical analysis is beyond the scope of this report. However, a brief discussion of chronological Monte Carlo simulation will establish the rational for its choice for this study.

There are three broad modeling approaches that could have been used for the EPRI spares analyses: Poisson, Markov and chronological Monte Carlo. Only the latter can account for non-exponential distributions for input parameters and provide probability distributions of the calculated simulation results.

Monte Carlo Simulation (MCS) is an established methodology for reliability evaluations. In general for such studies, two approaches to MCS may be used: non-chronological MCS (also referred to as non-sequential MCS), where system states are randomly sampled, and chronological MCS (also referred to as sequential MCS), where the time dependent, i.e. chronological, behavior of the system is simulated by sampling sequences of system states over multiple time periods created from the individual component chronological state transitions.

Chronological MCS (CMCS) sequentially simulates the states of the system in chronological order and can provide information not obtainable with non-chronological MCS or Markov models but requires parameters distributions for each component state duration. CMCS is a well-recognized technique in power system analysis, particularly for assessing generation reliability. (Ref: 1, 2, and 3) The disadvantage of CMCS is that it requires more computational time and storage.

CMCS allows for the least restrictive modeling assumptions and provides the most useful output results of the three broad approaches. Importantly, for the EPRI spares simulation studies, only CMCS simulations can provide information about the chronological aspects of the transformer fleet performance as determined by the chronological operating performance of individual transformers. For example, because age-dependent Weibull hazard rates are used, the failure rates for each transformer are determined by that transformer's age and change for each year of the study as the individual transformers age (non-exponential distributions).

Furthermore, only CMCS can account for cases where the spare waiting times depend, not only on the failure of other transformers, but also on the ordering and manufacturing delays of replacement spares or even the complete depletion of the spares stock. For example, in the EPRI simulation, replacement spares may be ordered but not available for some variable delay time beginning at any time in the simulation period or even before. Mobile units may not be available for an arbitrary time period if they are being utilized in other locations but may eventually become again available. In addition, only CMCS can accommodate arbitrary system restrictions, e.g. particular spares only suitable for specific positions due to physical limitations.

Another important distinction of the EPRI CMCS-based spares analytics is the ability to provide probability distributions of the simulation results. For example, the methodology can provide the probability density function (PDF) of the probability of the occurrence of single and multiple simultaneous unfilled positions, the PDF of the residence times in any unfilled position state or the PDF that the unfilled position state will be longer than some time period. Such

PDF's are very useful for fully assessing risk. Neither Poisson nor Markov models can provide PDF's. (4)

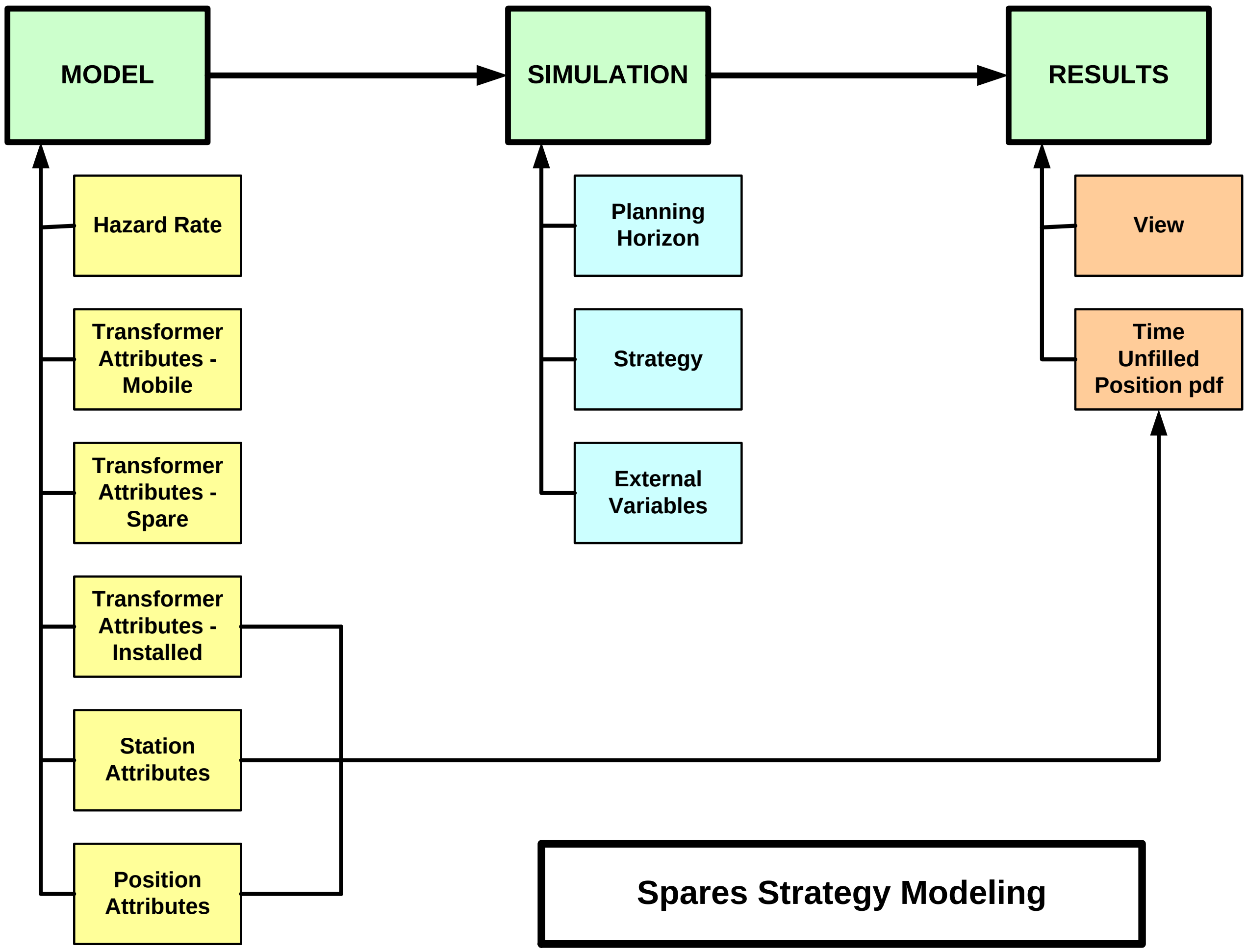


Figure 2-2
Proposed Spares Strategy Analytics Approach

Model Implementation

The spares strategy addresses:

- Stock level
- Allocation rules
- Reorder rules

External variables include:
- New spare procurement time
- New spare manufacturing time

- New spare shipping time
- Installation time

Modeling results include:
- View – chart, graph, tables
- Metrics: Unfilled position time by
  - Station
  - Specified transformer attributes
  - Criticality
  - Circuit connection
  - Combination of the above
- Probability of using nth spare
- Probability Density Function of spares to maintain some criteria

A modeling simulation flow chart is shown in Figure 2-3.

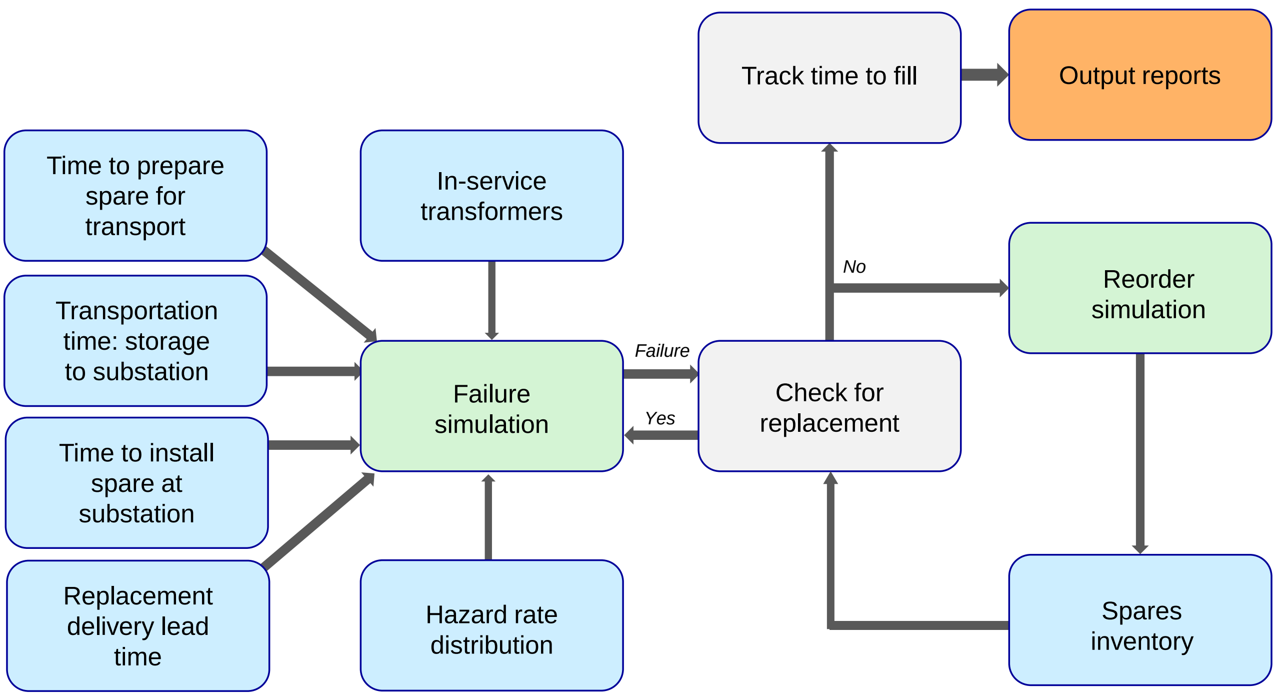


Figure 2-3
Modeling Simulation

Methodology

The methodology simulates the performance of the transformers over the planning horizon. Performance in this case refers to simply whether the transformer remains in service. The output is presented in a history table that indicates whether or not a transformer is in service for each day of the period. Each simulation develops its own history table and the final output is determined by the distribution of results from multiple simulations.

The results presented in the following chapter are composed of the distribution that results from the summation of history tables where, the number of days is equal to 1826.25 (accounting for leap year) days and a total number of positions for that particular transformer type. It is important to note that this approach has the ability to calculate the risk associated with multiple, simultaneous unfilled positions.

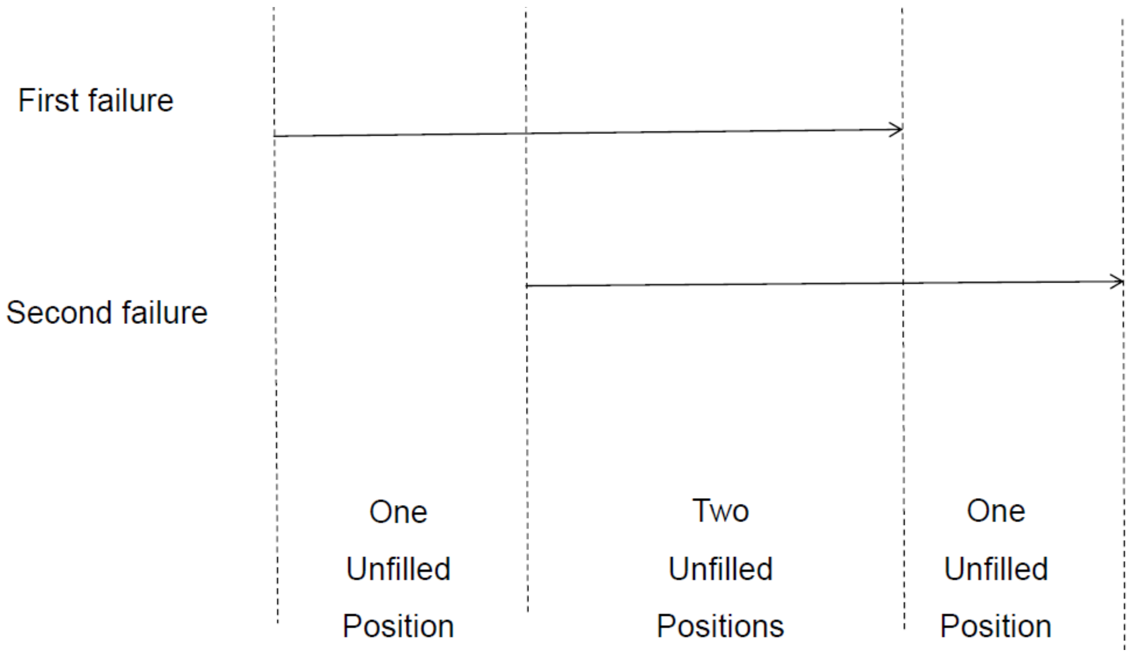


Figure 2-4
Failure Scenarios

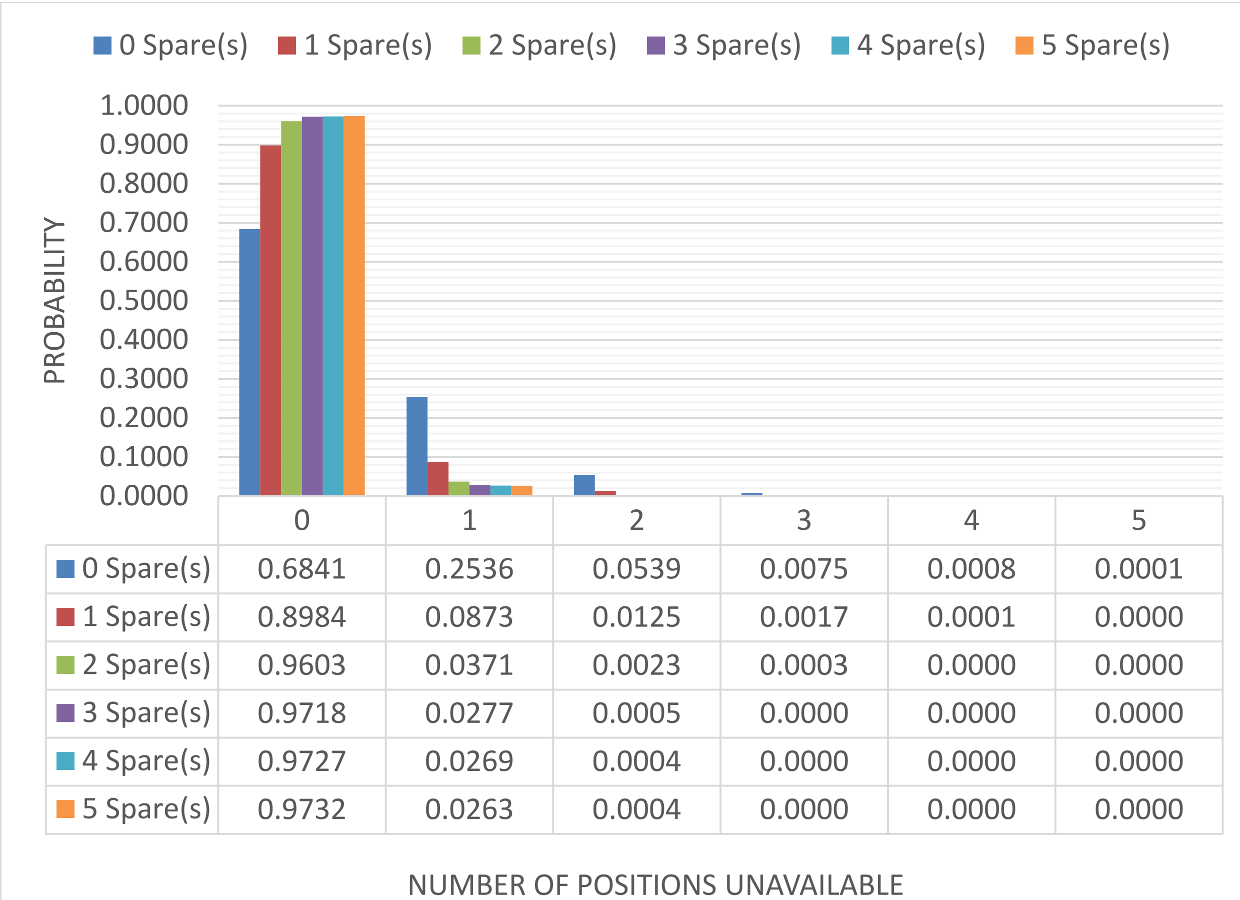
One result is shown below for assessing system availability (all transformer positions in service = 100% availability) for different possible numbers of spares. For zero spares the system availability is 68.41% whereas it is unavailable 31.59% of time. This unavailability is composed of:

- 25.36% due to one unavailable position
- 5.39% due to two positions simultaneously unavailable
- 0.75% due to three positions simultaneously unavailable
- 0.08% due to four positions simultaneously unavailable
- 0.01% due to five positions simultaneously unavailable

For one spare the system availability is 89.84% whereas it is unavailable 10.16% of time. This unavailability is composed of:

- 8.73% due to one unavailable position
- 1.25% due to two positions simultaneously unavailable
- 0.17% due to three positions simultaneously unavailable
- 0.01% due to four positions simultaneously unavailable
- 0.00% due to five positions simultaneously unavailable

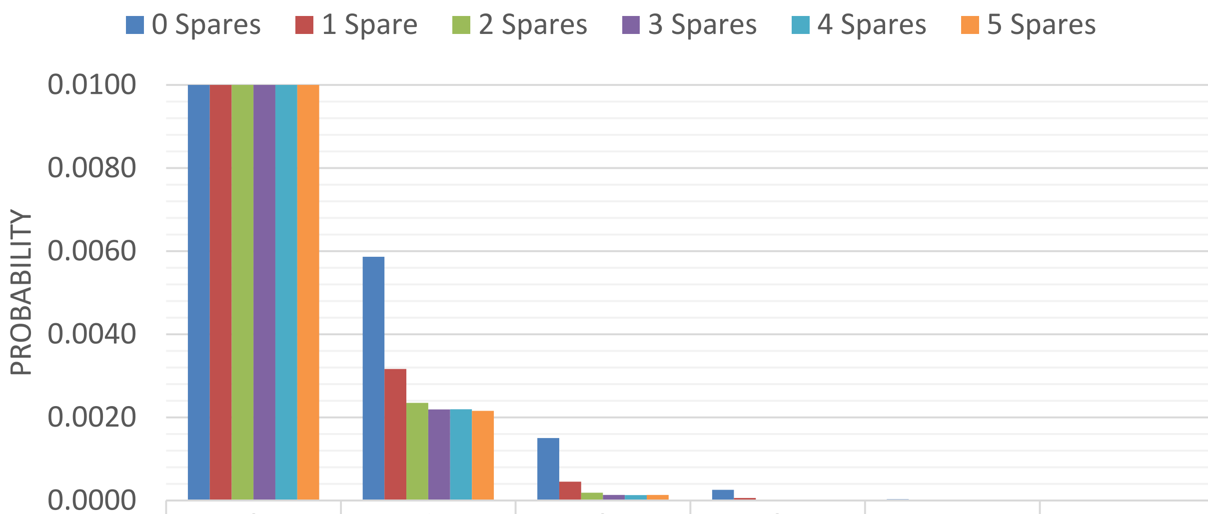
It can be observed that there is less than 0.1% change in availability in going from three to four spares.



	0	1	2	3	4	5
0 Spare(s)	0.6841	0.2536	0.0539	0.0075	0.0008	0.0001
1 Spare(s)	0.8984	0.0873	0.0125	0.0017	0.0001	0.0000
2 Spare(s)	0.9603	0.0371	0.0023	0.0003	0.0000	0.0000
3 Spare(s)	0.9718	0.0277	0.0005	0.0000	0.0000	0.0000
4 Spare(s)	0.9727	0.0269	0.0004	0.0000	0.0000	0.0000
5 Spare(s)	0.9732	0.0263	0.0004	0.0000	0.0000	0.0000

Figure 2-5
System Availability for Different Numbers of Spares

The results for position-days availability are also provided as shown in the figure below:



	0	1	2	3	4	5
0 Spares	0.9923	0.0059	0.0015	0.0003	0.0000	0.0000
1 Spare	0.9963	0.0032	0.0005	0.0001	0.0000	0.0000
2 Spares	0.9974	0.0024	0.0002	0.0000	0.0000	0.0000
3 Spares	0.9977	0.0022	0.0001	0.0000	0.0000	0.0000
4 Spares	0.9977	0.0022	0.0001	0.0000	0.0000	0.0000
5 Spares	0.9977	0.0022	0.0001	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Figure 2-6
Position Days Availability

For zero spares 99.23% of the position-days have a transformer available or for 0.77% of the time some positions are unavailable.

There is essentially no change in availability in going from two to three spares.

It is important to note that the analytical results are produced from random simulations. As a consequence, numerical values may change slightly if the exact same scenario is run another time. The differences are very small but may lead to unexpected, apparently anomalous results, such as an increase in probabilities of unfilled positions with an increase in the number of spares. These changes simply reflect the repeatability of the simulations, in effect the confidence interval around the results. They do not detract from the usefulness of the results, which readily show the number of spares where the probabilities tend to converge. These variations are a function not only of the number of simulations run but also the size of the population being studied. Hence, such variations are more likely to be evidenced in small transformer fleet analyses.

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3
SPARES REQUIREMENT ASSESSMENT RESULTS

Overview

This chapter presents inputs and analysis by transformer groups as by provided by Hydro One. For example:

- 250 MVA 230/115 kV
- 125 MVA 230/115 kV

For each group the assumptions required for the simulation as provided by Hydro One are presented first. For example:

- Lead time to order a new spare
- Minimum Threshold time for Counting Unavailable Position

The analysis results are provided from two perspectives:

- What is the probability that the system is not at full availability at any time?
- What is the probability that all positions are available for all days?

Summary of Select Results

The following table summarizes select results for transformer groups provided by Hydro One.

Table 3-1
Summary of Select Results

Study Group	System Availability (What is the probability that the system is not at full availability at any time?)		
	2 Spares	3 Spares	4 Spares
125 MVA 230/44 kV	90.88	94.37	95.23
125 MVA 230/28-28 kV	89.09	91.67	92.11
83 MVA 230/28 kV	96.50	97.32	97.30
83 MVA 230/44 kV	97.25	97.81	97.83
100 MVA 230/14-14 kV	99.67	99.66	99.65
250 MVA 230/115 kV	96.03	97.18	97.27
125 MVA 230/115 kV	98.43	98.60	98.61
75 MVA 115/14-14 kV	81.31	89.48	92.17
42MVA 115/14 kV	99.85	99.85	99.85
42MVA 115/28k kV	93.69	94.36	94.28
83MVA 115/28 kV	97.35	98.22	98.30
42 MVA 115/44 kV	98.01	98.5	98.54
100 MVA 115/14-14 kV	81.03	81.09	80.94
750 MVA 500/230 kV	91.54	93.59	93.96

The assumptions in the bulleted list below and in the following figures are necessary for running the simulations for each transformer study group. The assumptions were provided by Hydro One.

125 MVA 230/44 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unfilled position: 60 days

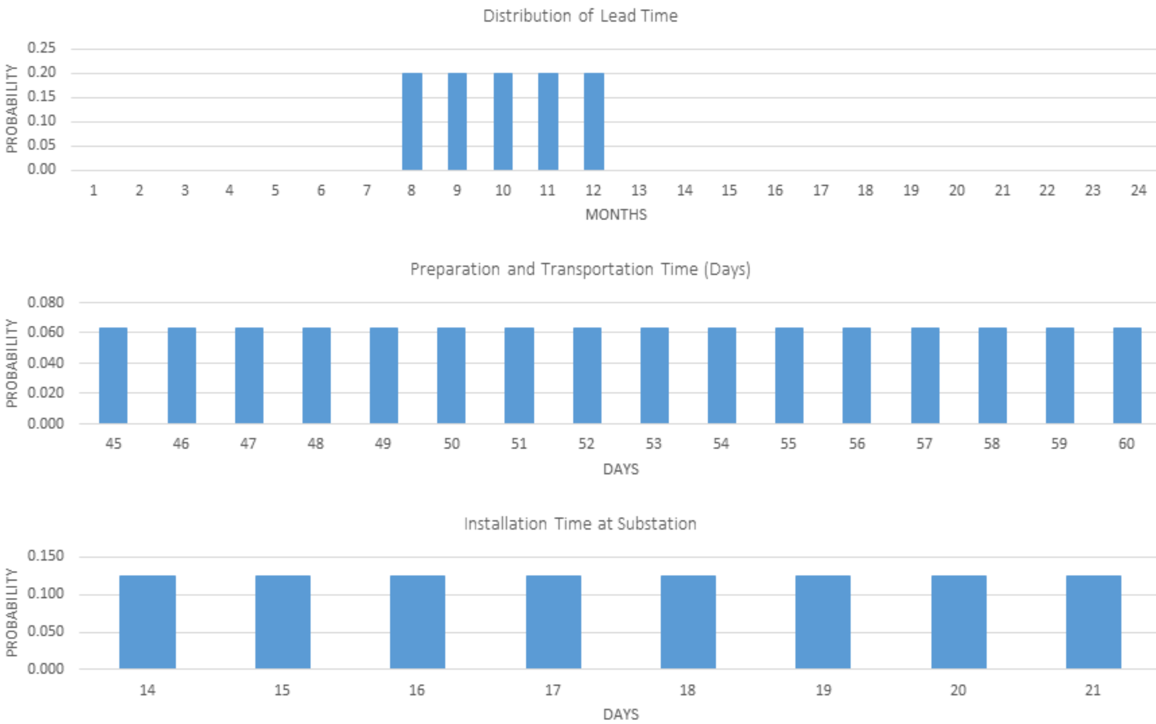


Figure 3-1
Assumptions for Running Simulations: 125 MVA 230/44 kV Inputs – Time Distributions (Hydro One data)

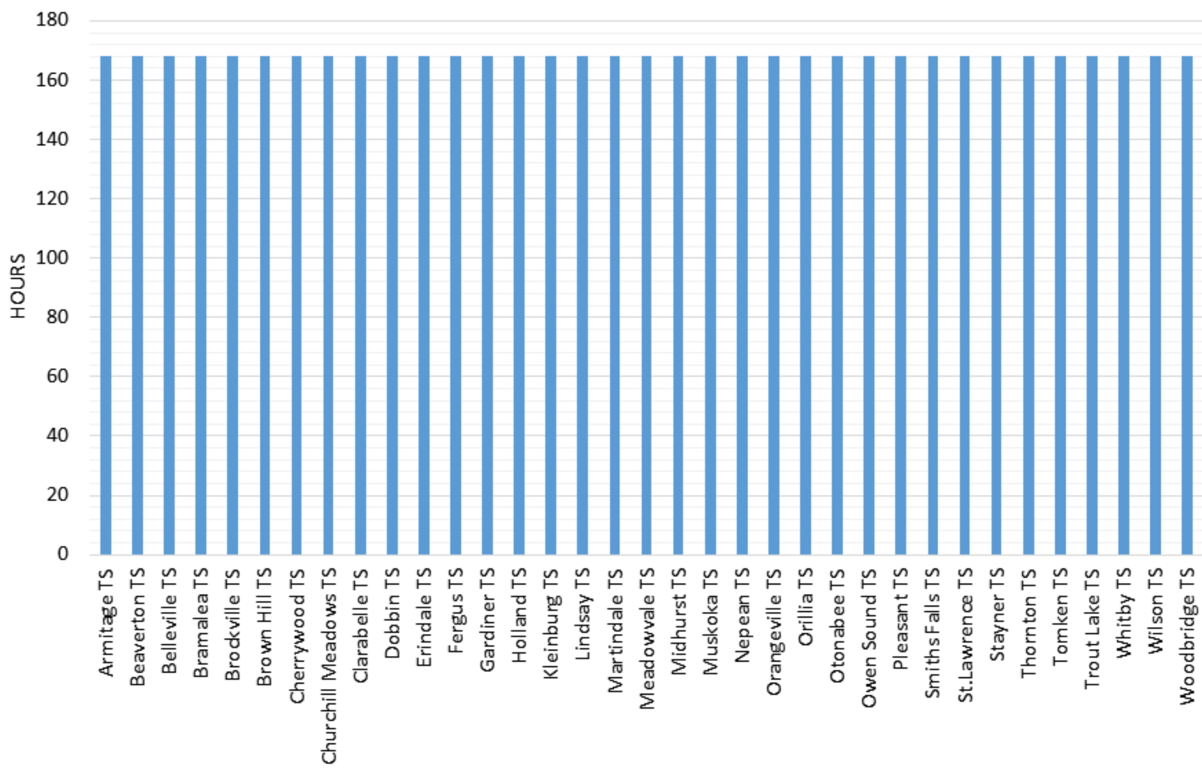


Figure 3-2
125 MVA 230/44 kV Inputs: Transportation Time from Spare Depot to Substation

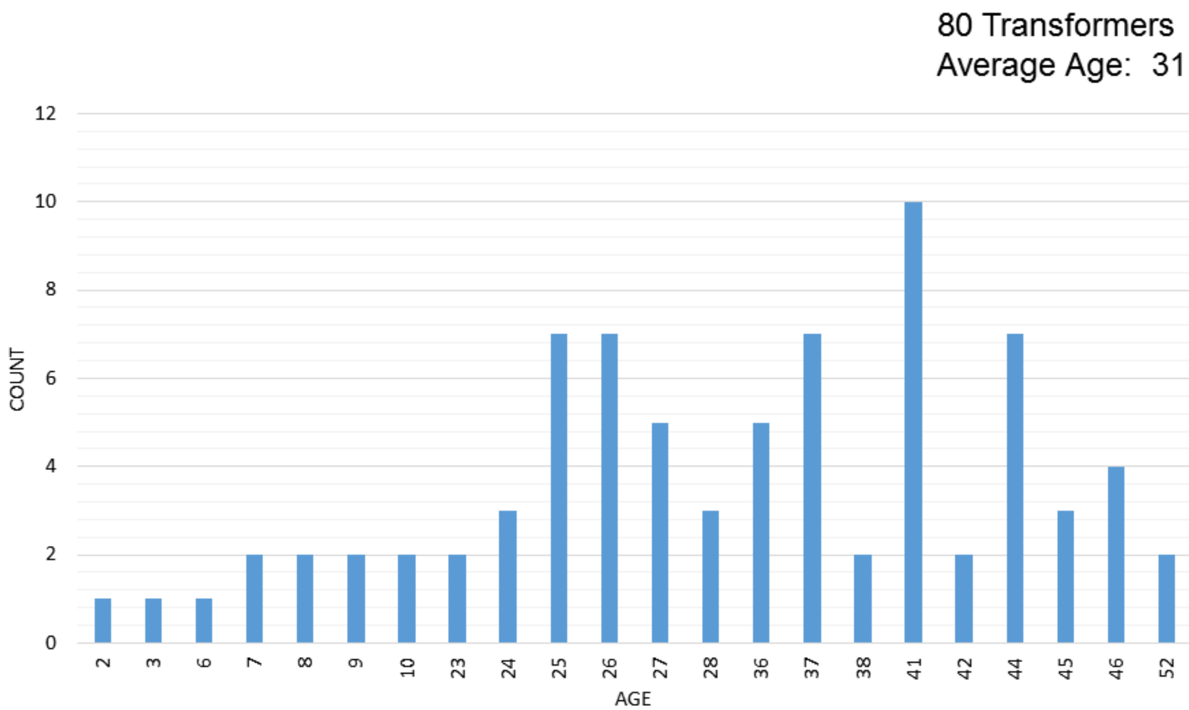


Figure 3-3
125 MVA 230/44 kV Inputs – Transformer Age Demographics (Hydro One data)

The following figure presents the Hazard Rate required for simulation as developed by EPRI using replacement data provided by Hydro One.

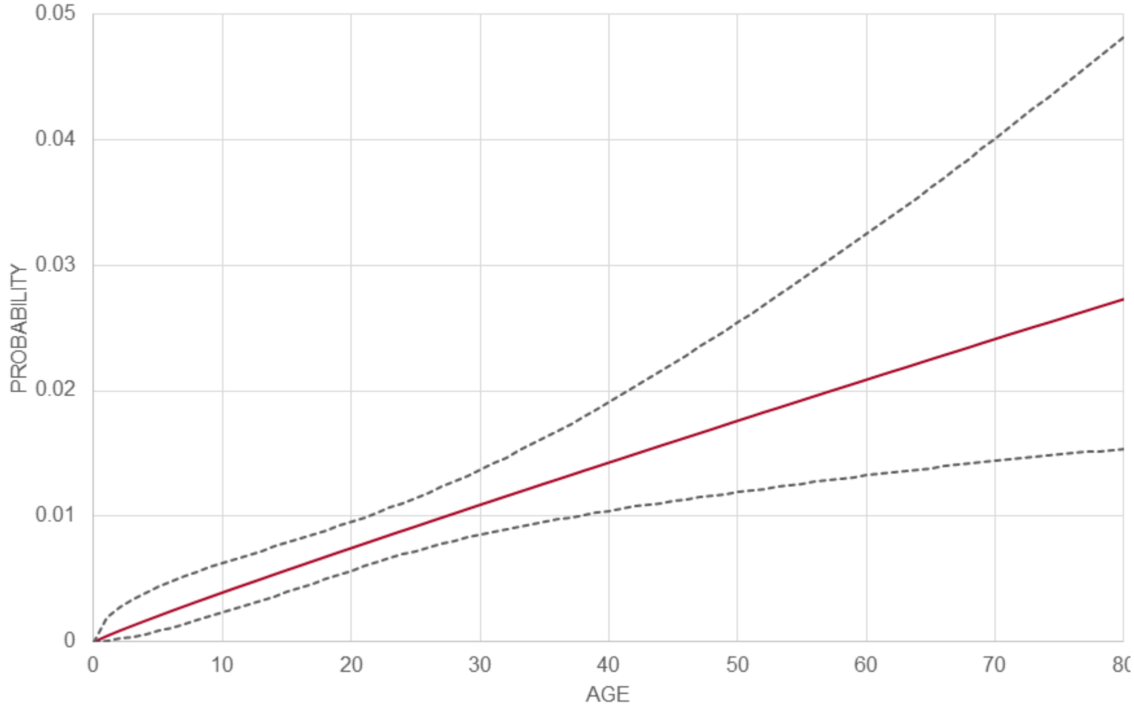


Figure 3-4
125 MVA 230/44 kV Inputs Hazard Function

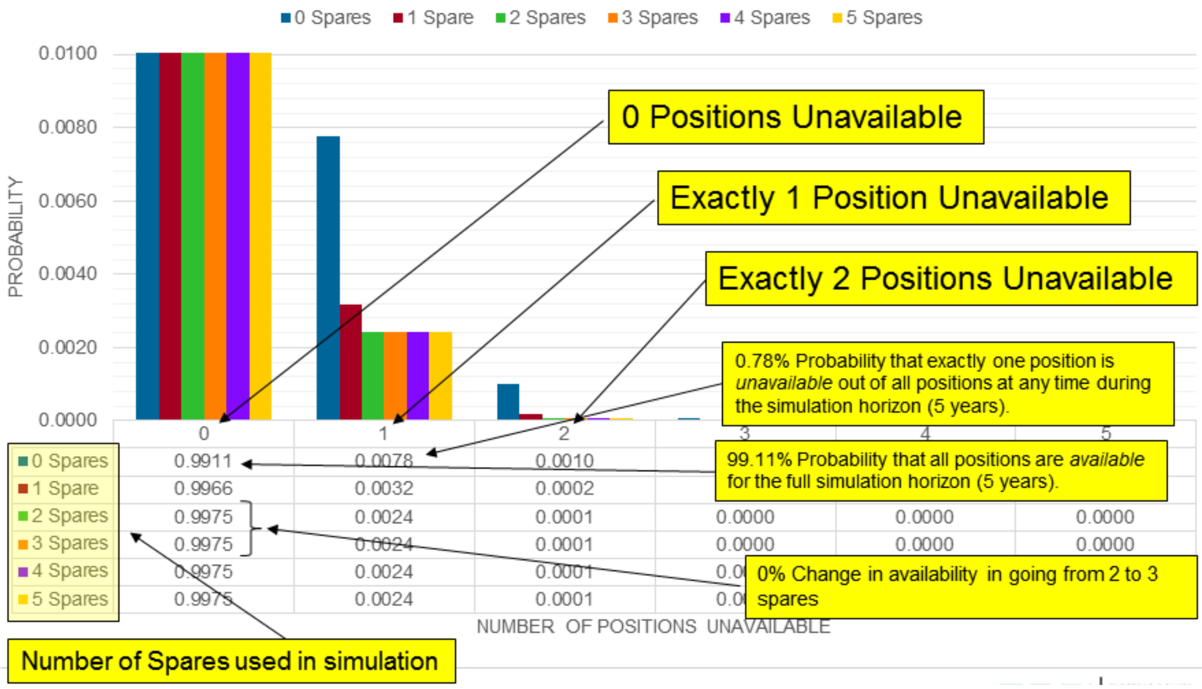


Figure 3-5
what is the probability that all positions are available for all days? Minimum Threshold time for Counting Unavailable Position: 60 Days (80 positions)

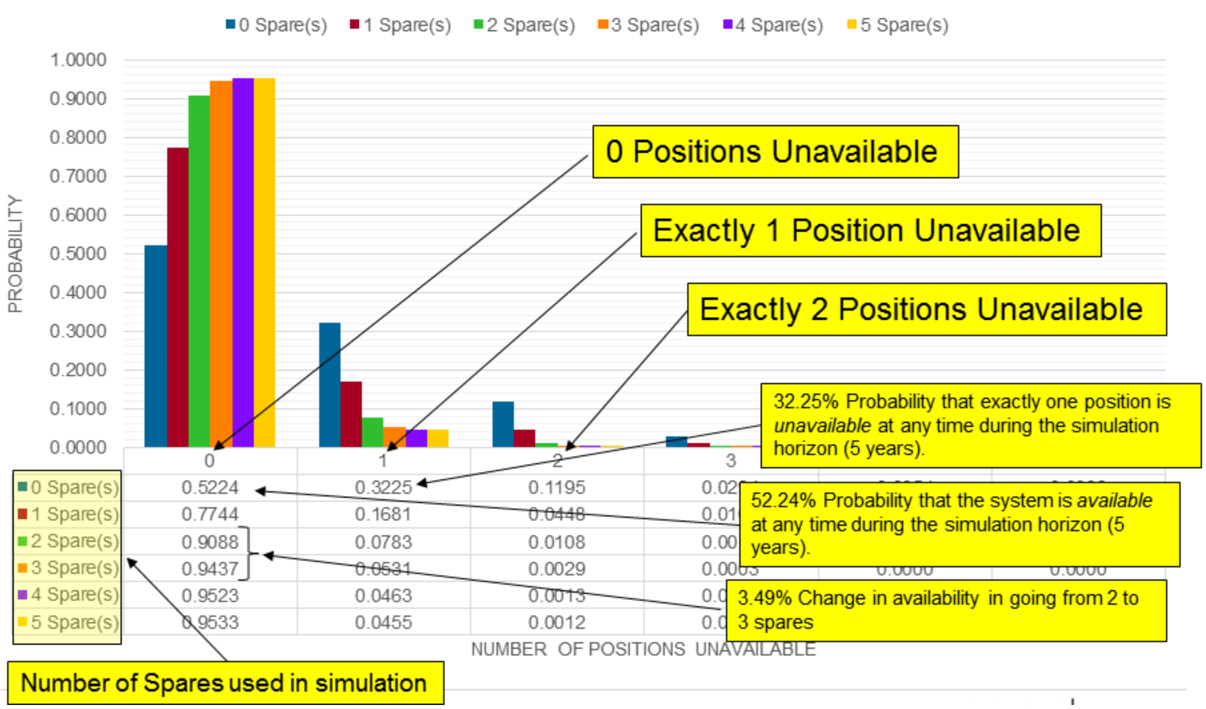


Figure 3-6
What is the probability that the system is not at full availability at any time? Minimum Threshold time for Counting Unavailable Position: 60 Days (80 positions)

125 MVA 230/28-28 kV

Inputs

Inputs for the 125 MVA 230/28-28 transformer group are as follows:

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

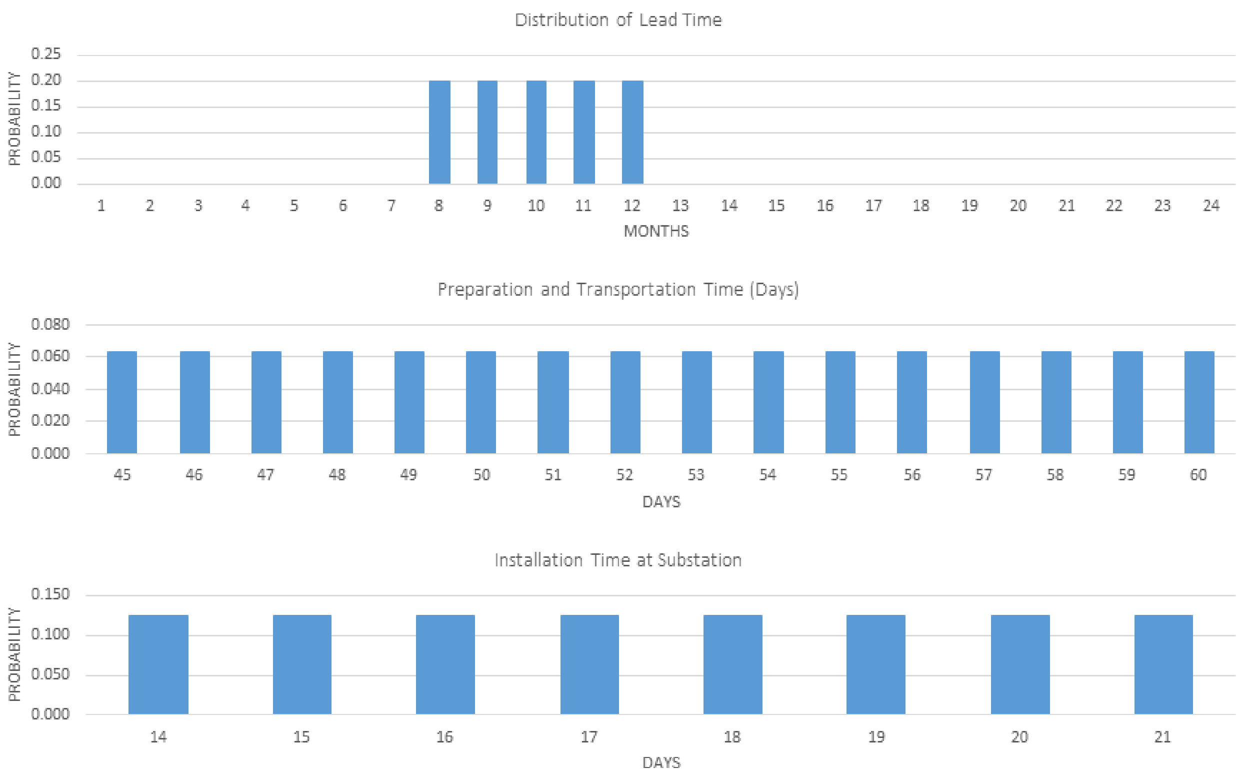


Figure 3-7
125 MVA 230/28-28 kV Inputs – Time Distributions

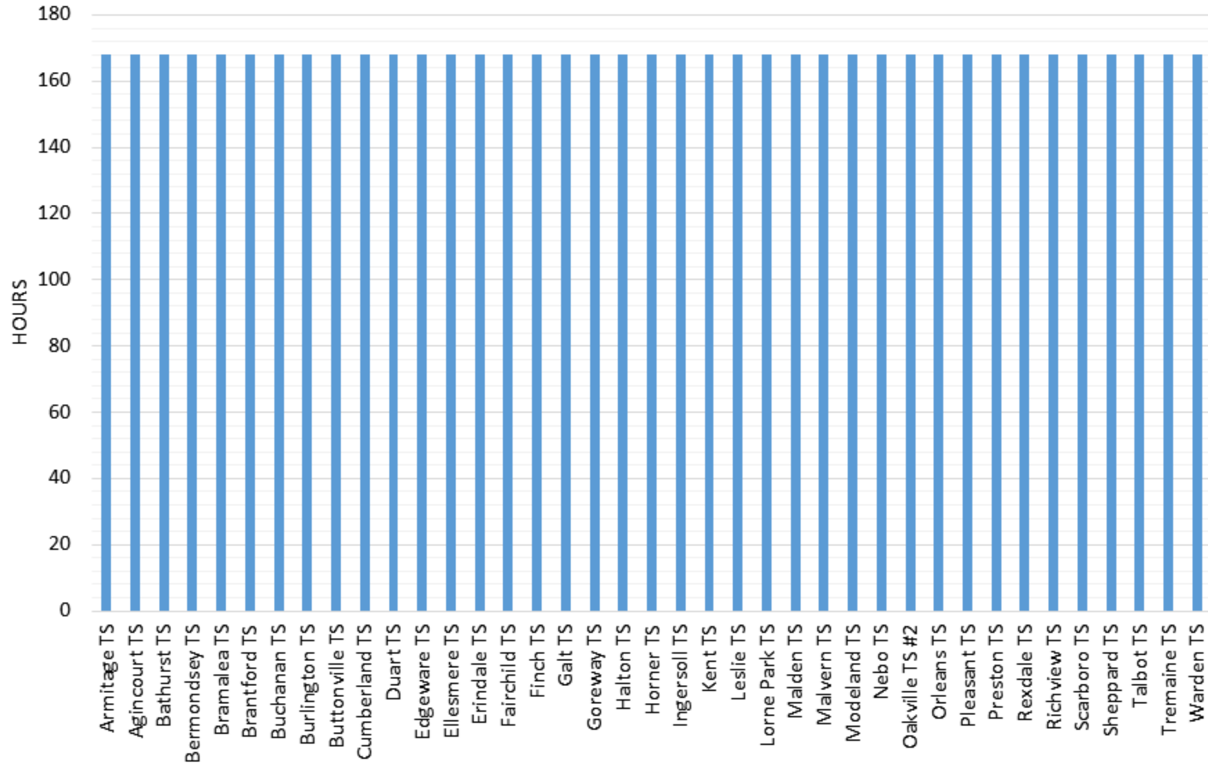


Figure 3-8
125 MVA 230/28-28 kV Inputs – Transportation Time from Spare Depot to Substation

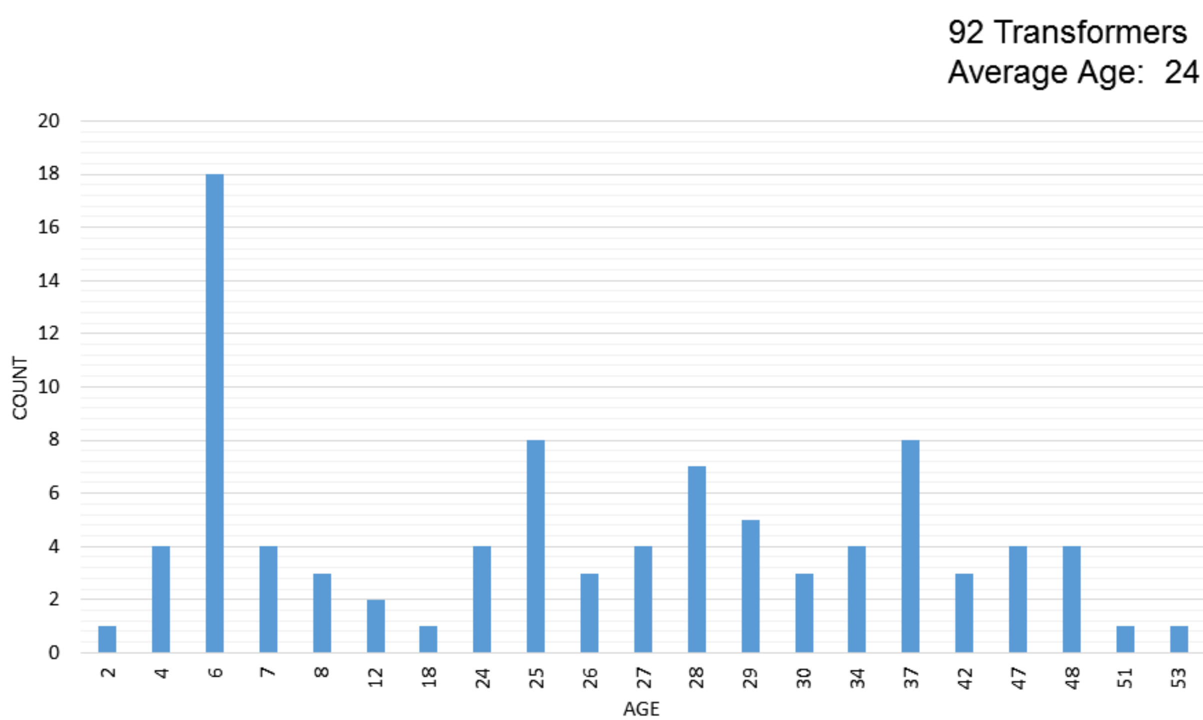


Figure 3-9
125 MVA 230/28-28 kV Inputs – Transformer Age Demographics

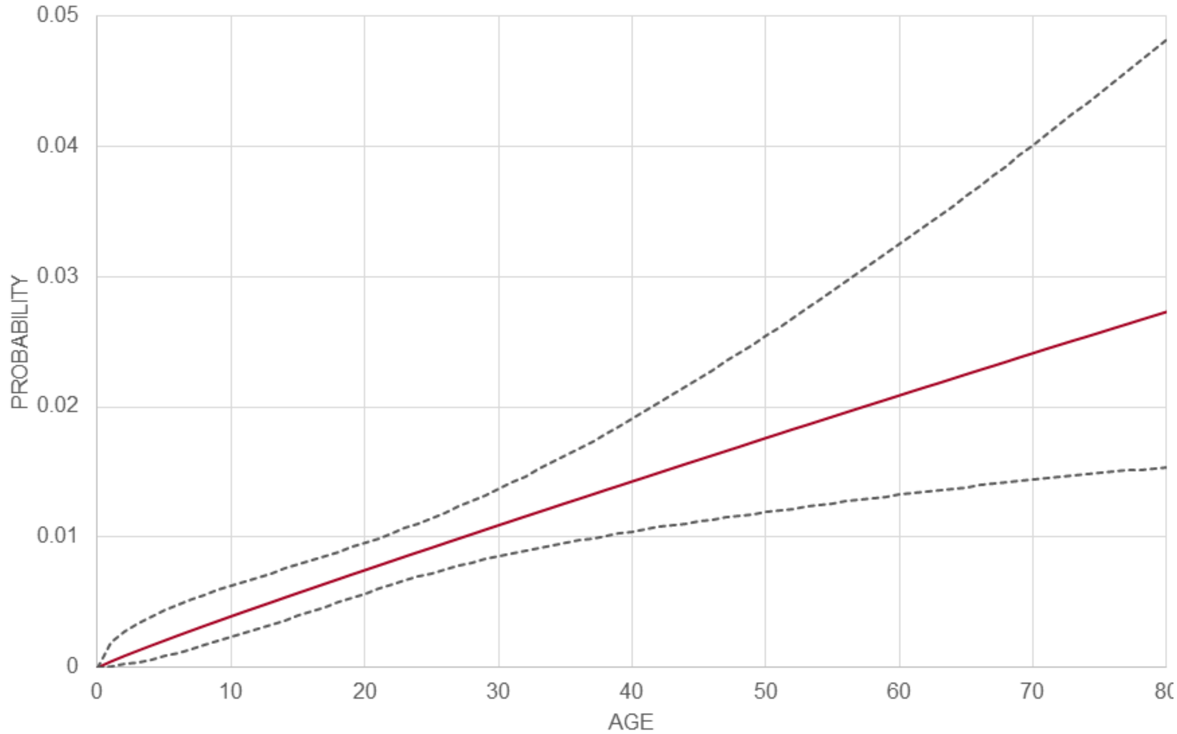
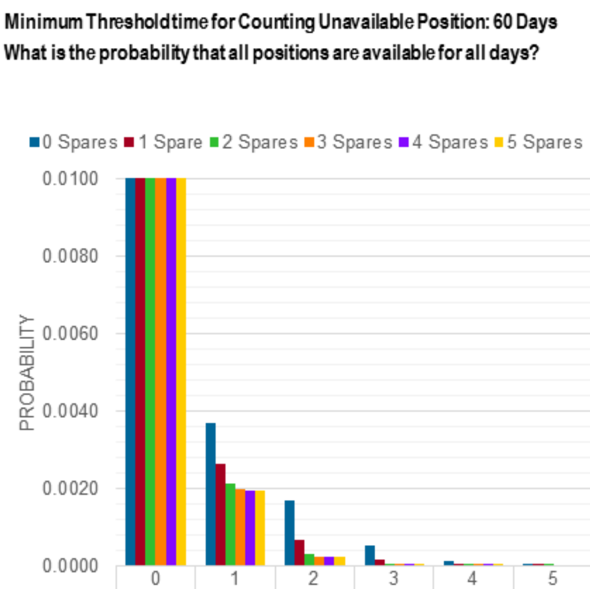
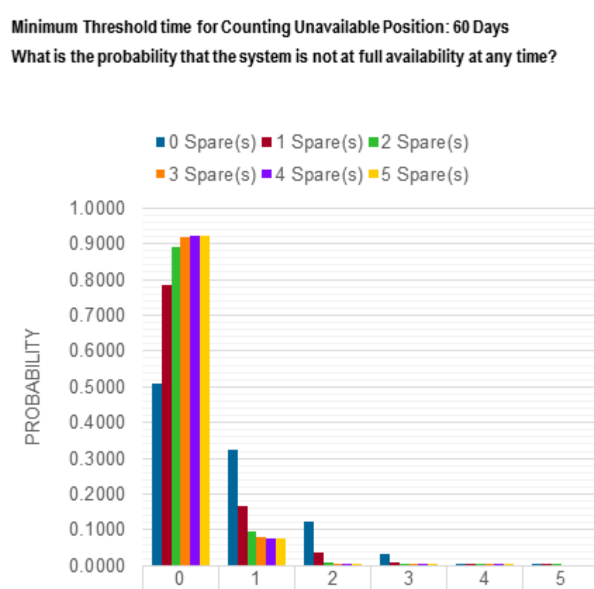


Figure 3-10
125 MVA 230/28-28 kV Inputs – Hazard Function



	0	1	2	3	4	5
0 Spares	0.9940	0.0037	0.0017	0.0005	0.0001	0.0000
1 Spare	0.9965	0.0026	0.0007	0.0002	0.0000	0.0000
2 Spares	0.9975	0.0021	0.0003	0.0000	0.0000	0.0000
3 Spares	0.9978	0.0020	0.0002	0.0000	0.0000	0.0000
4 Spares	0.9978	0.0019	0.0002	0.0000	0.0000	0.0000
5 Spares	0.9978	0.0020	0.0002	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE



	0	1	2	3	4	5
0 Spare(s)	0.5103	0.3230	0.1253	0.0339	0.0065	0.0010
1 Spare(s)	0.7846	0.1679	0.0377	0.0080	0.0015	0.0003
2 Spare(s)	0.8909	0.0971	0.0105	0.0013	0.0002	0.0000
3 Spare(s)	0.9167	0.0787	0.0043	0.0003	0.0000	0.0000
4 Spare(s)	0.9211	0.0754	0.0033	0.0001	0.0000	0.0000
5 Spare(s)	0.9211	0.0754	0.0033	0.0001	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Figure 3-11
125 MVA 230/28-28 kV Results

83 MVA 230/28 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

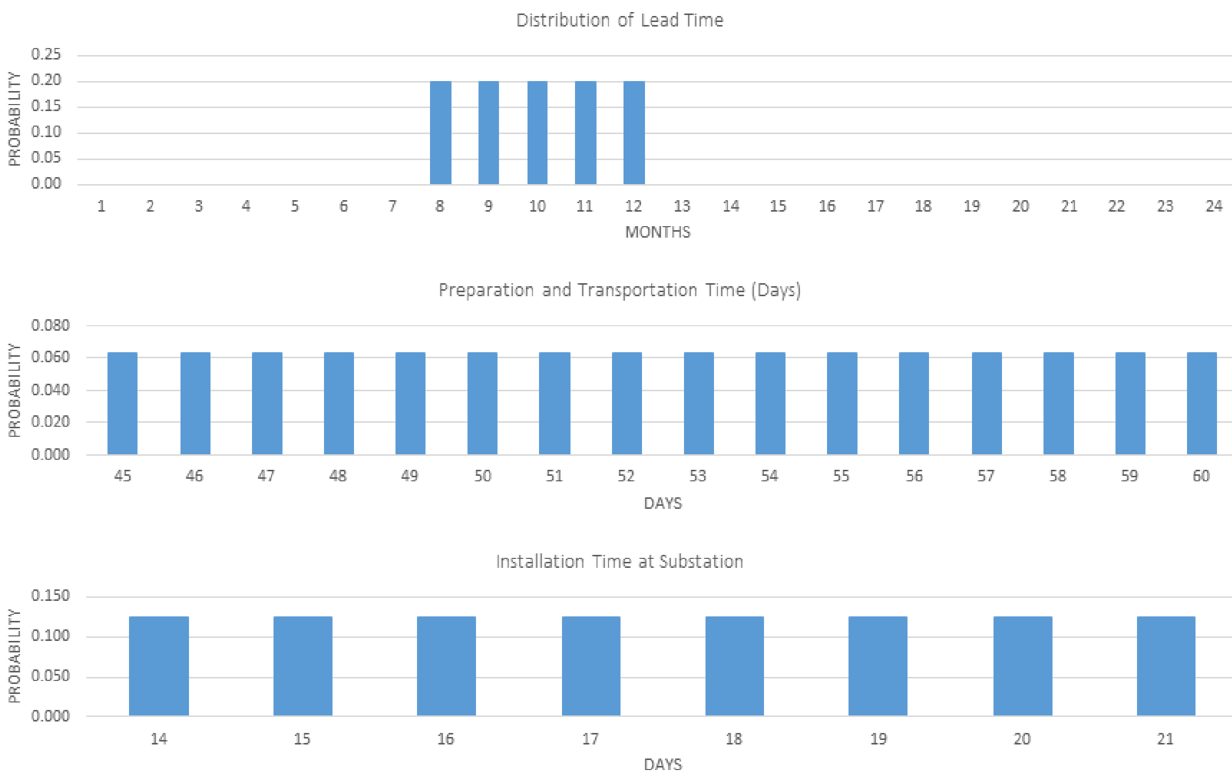


Figure 3-12
83 MVA 230/28 kV Inputs – Time Distributions

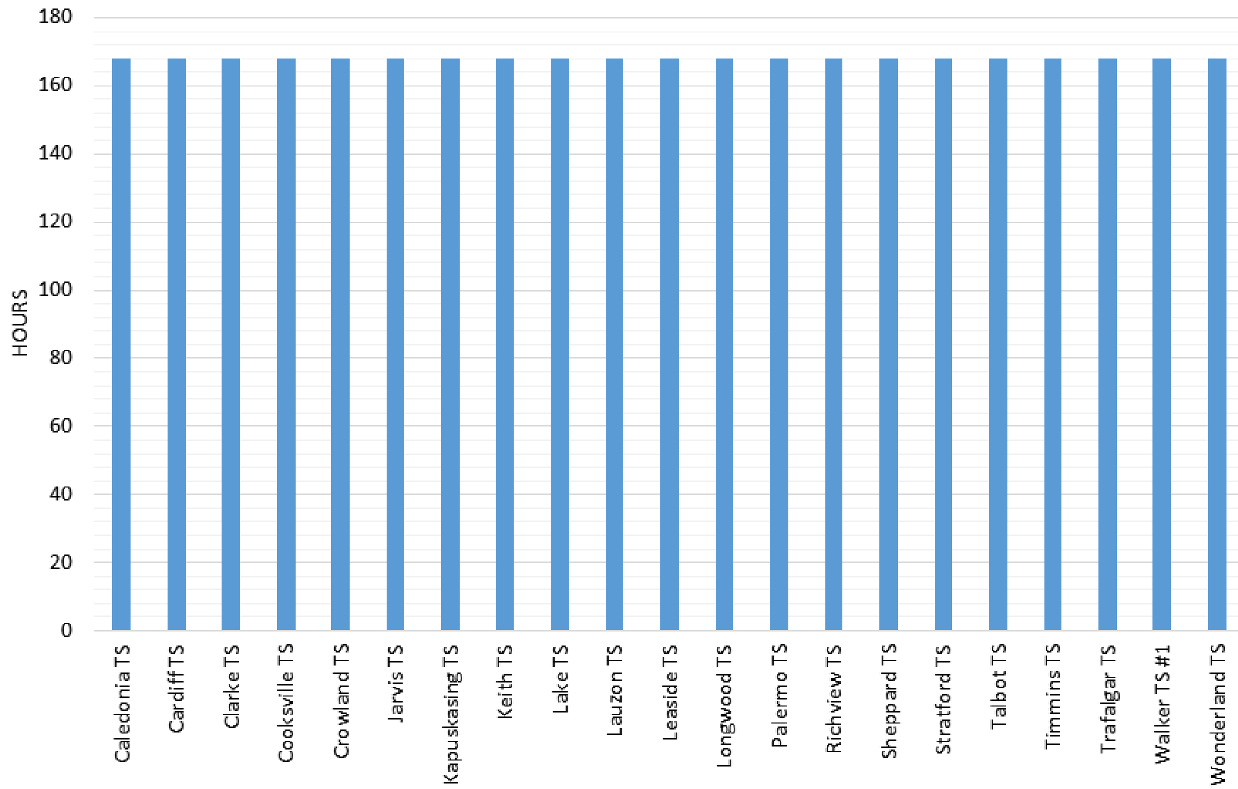


Figure 3-13
83 MVA 230/28 kV Inputs –Transportation Time from Spare Depot to Substation

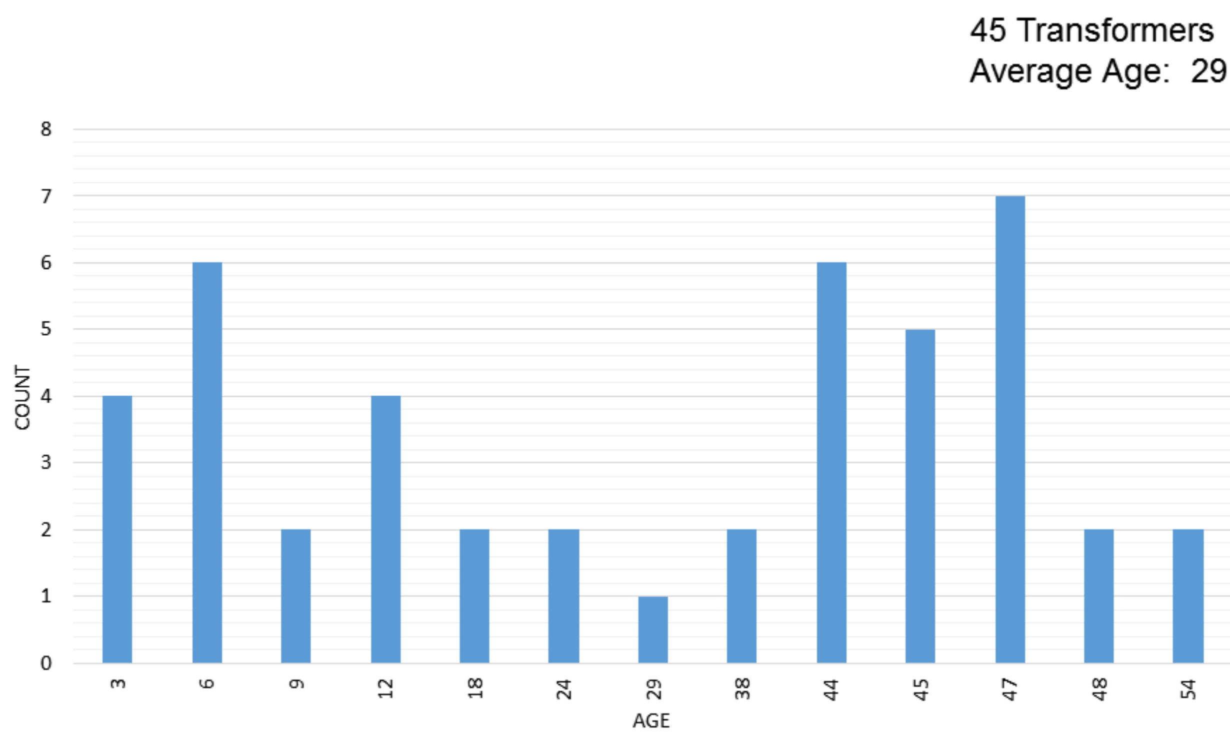


Figure 3-14
83 MVA 230/28 kV Inputs – Transformer Age Demographics

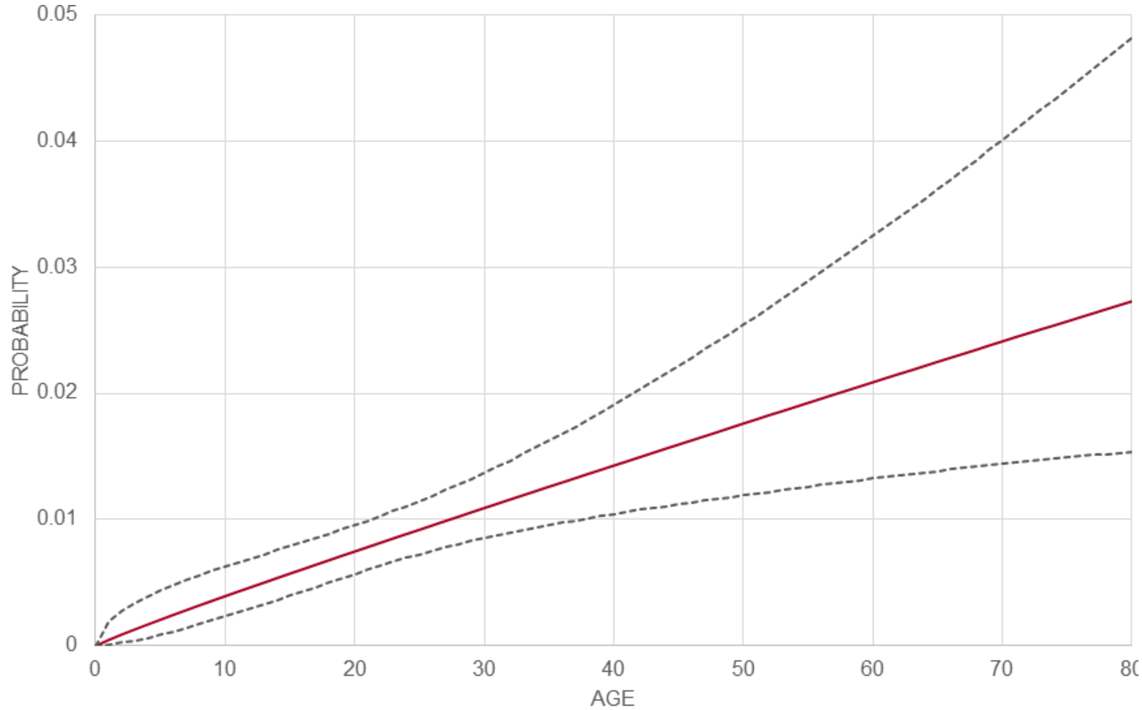
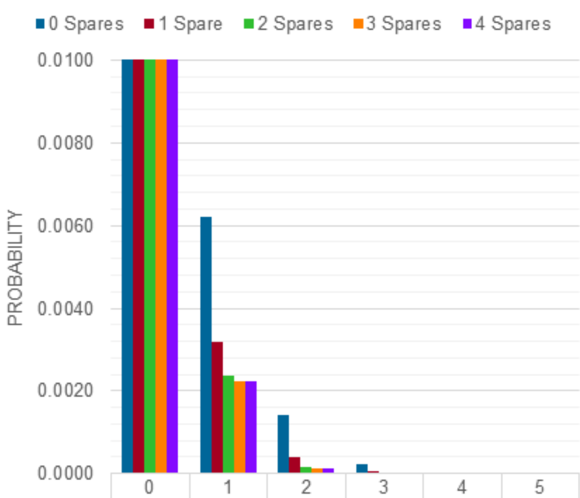


Figure 3-15
83 MVA 230/28 kV Inputs –Hazard Function

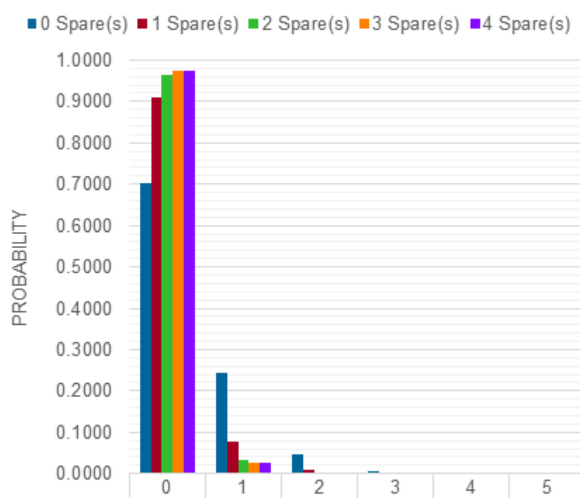
Minimum Thresholdtime for Counting Unavailable Position: 60 Days
What is the probability that all positions are available for all days?



	0	1	2	3	4	5
0 Spares	0.9921	0.0062	0.0014	0.0002	0.0000	0.0000
1 Spare	0.9964	0.0032	0.0004	0.0000	0.0000	0.0000
2 Spares	0.9975	0.0024	0.0002	0.0000	0.0000	0.0000
3 Spares	0.9976	0.0022	0.0001	0.0000	0.0000	0.0000
4 Spares	0.9976	0.0022	0.0001	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that the system is not at full availability at any time?



	0	1	2	3	4	5
0 Spare(s)	0.7026	0.2438	0.0467	0.0061	0.0007	0.0001
1 Spare(s)	0.9105	0.0786	0.0097	0.0011	0.0001	0.0000
2 Spare(s)	0.9650	0.0334	0.0014	0.0001	0.0000	0.0000
3 Spare(s)	0.9732	0.0263	0.0005	0.0000	0.0000	0.0000
4 Spare(s)	0.9730	0.0266	0.0004	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Figure 3-16
83 MVA 230/28 kV Results

83 MVA 230/44 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

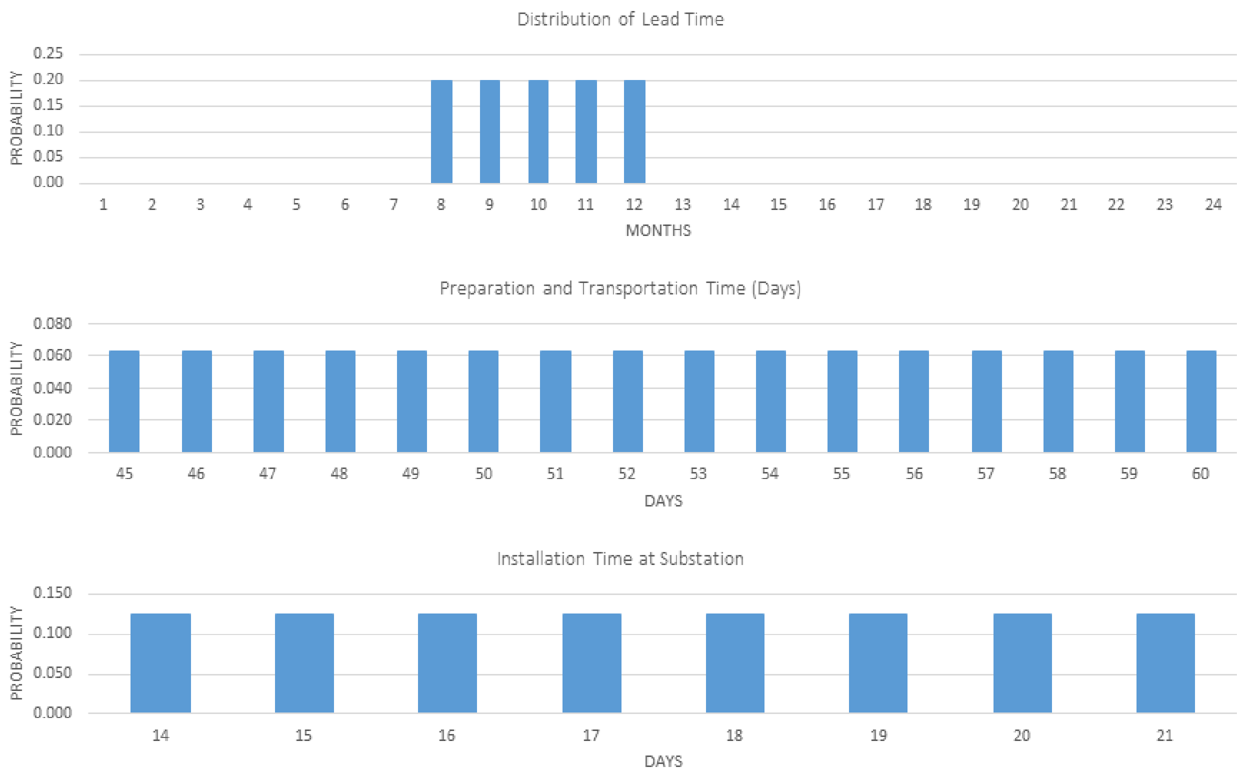


Figure 3-17
83 MVA 230/44 kV Inputs –Time Distributions

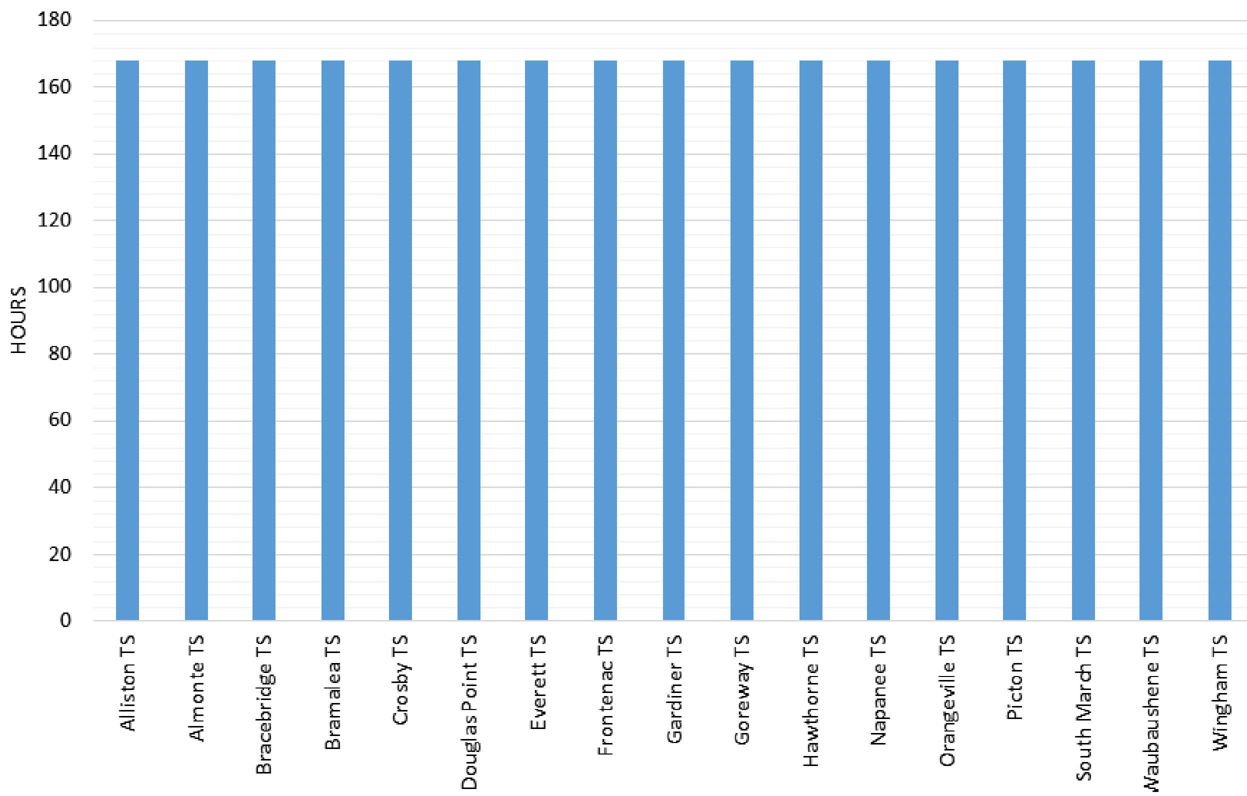


Figure 3-18
83 MVA 230/44 kV Inputs –Transportation Time from Spare Depot to Substation

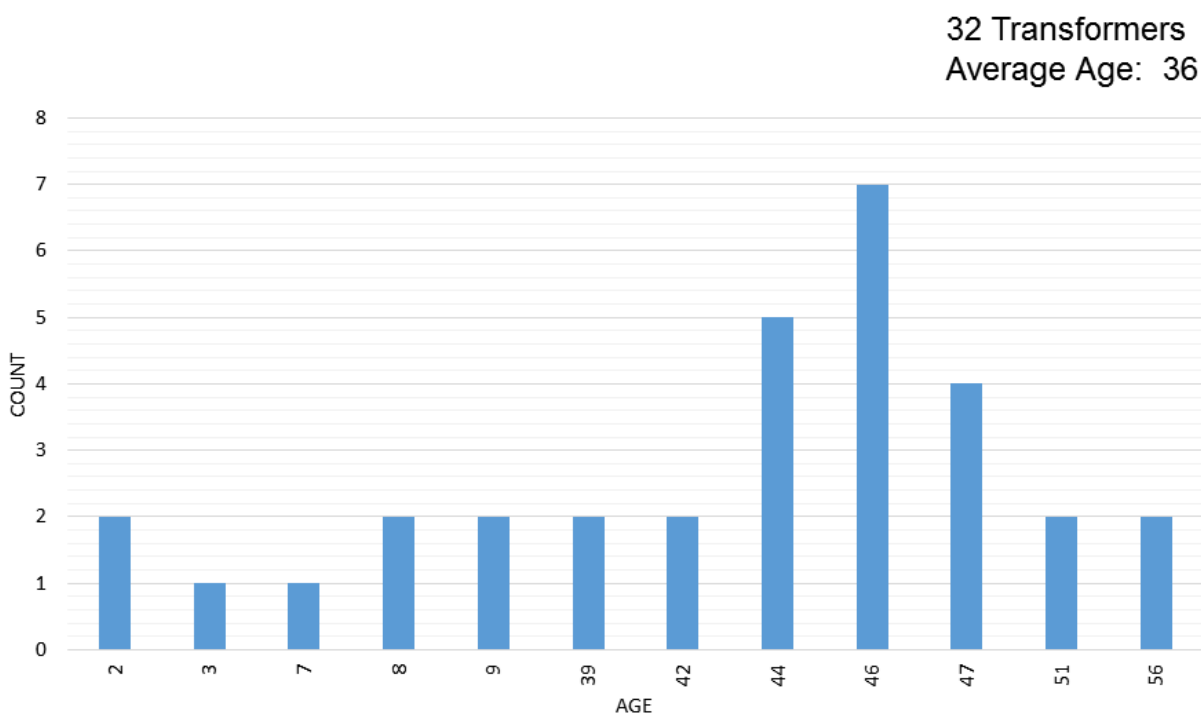


Figure 3-19
83 MVA 230/44 kV Inputs – Transformer Age Demographics

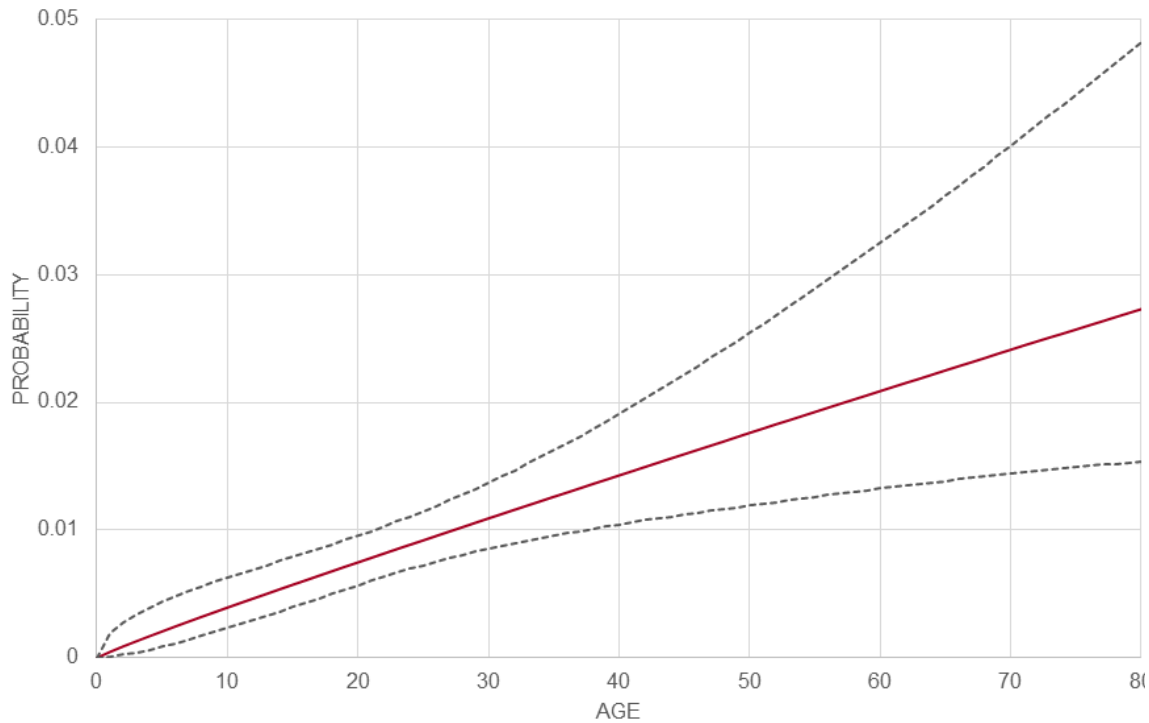
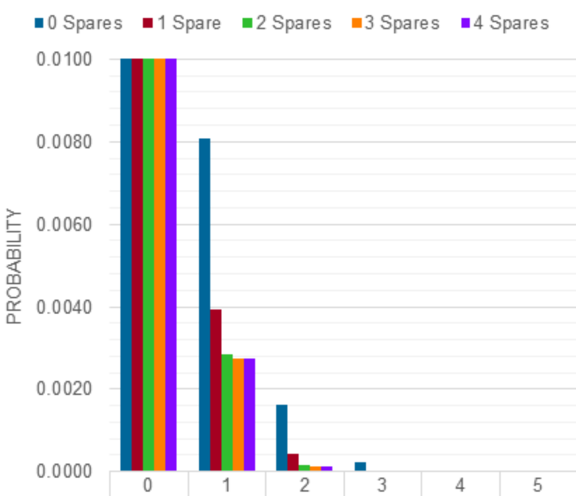


Figure 3-20
83 MVA 230/44 kV Inputs – Hazard Function

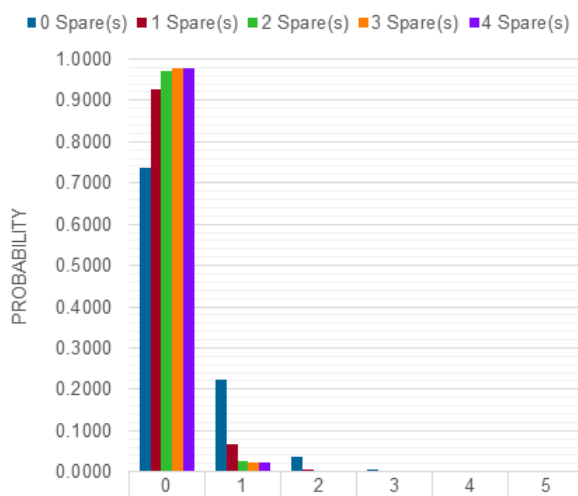
Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that all positions are available for all days?



	0	1	2	3	4	5
0 Spares	0.9901	0.0081	0.0016	0.0002	0.0000	0.0000
1 Spare	0.9956	0.0039	0.0004	0.0000	0.0000	0.0000
2 Spares	0.9970	0.0029	0.0002	0.0000	0.0000	0.0000
3 Spares	0.9971	0.0027	0.0001	0.0000	0.0000	0.0000
4 Spares	0.9971	0.0027	0.0001	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that the system is not at full availability at any time?



	0	1	2	3	4	5
0 Spare(s)	0.7348	0.2232	0.0374	0.0042	0.0004	0.0000
1 Spare(s)	0.9265	0.0660	0.0069	0.0006	0.0001	0.0000
2 Spare(s)	0.9725	0.0267	0.0008	0.0000	0.0000	0.0000
3 Spare(s)	0.9781	0.0217	0.0003	0.0000	0.0000	0.0000
4 Spare(s)	0.9783	0.0214	0.0003	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Figure 3-21
83 MVA 230/44 kV Results

100 MVA 230/14-14 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

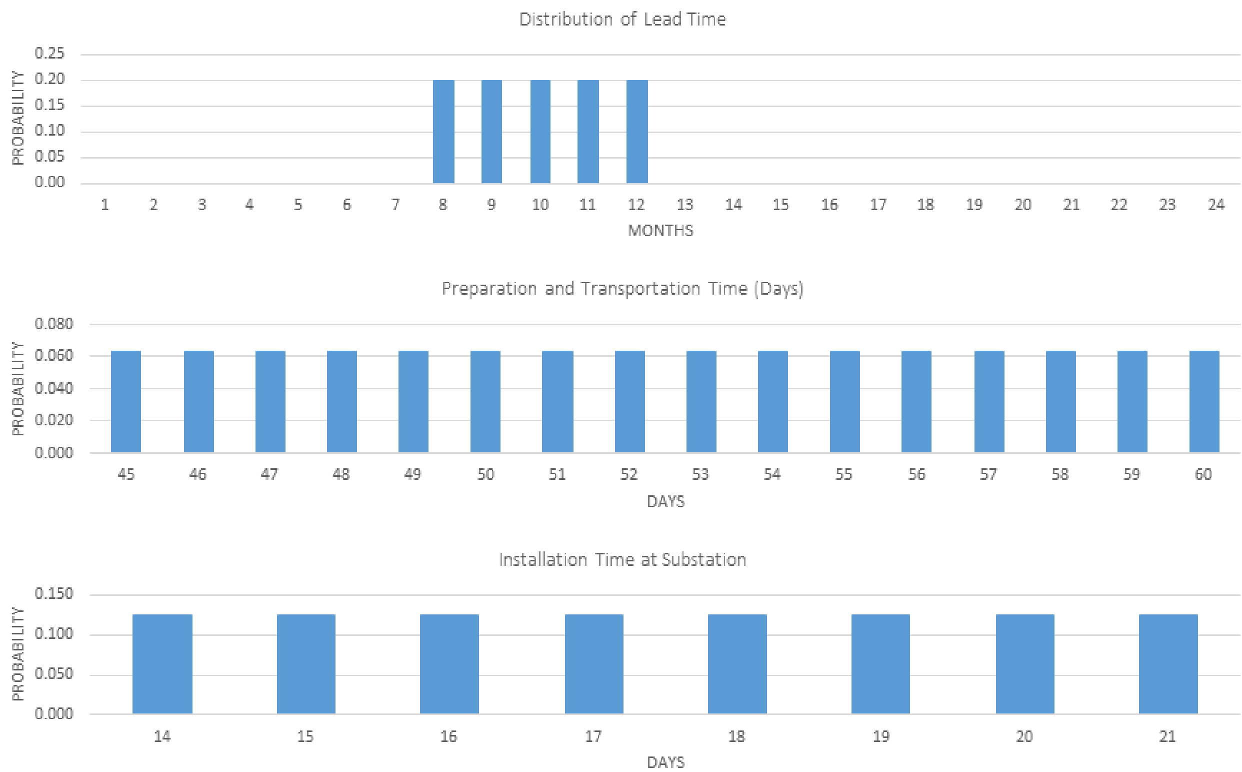


Figure 3-22
100 MVA 230/14-14 kV Inputs – Time Distributions

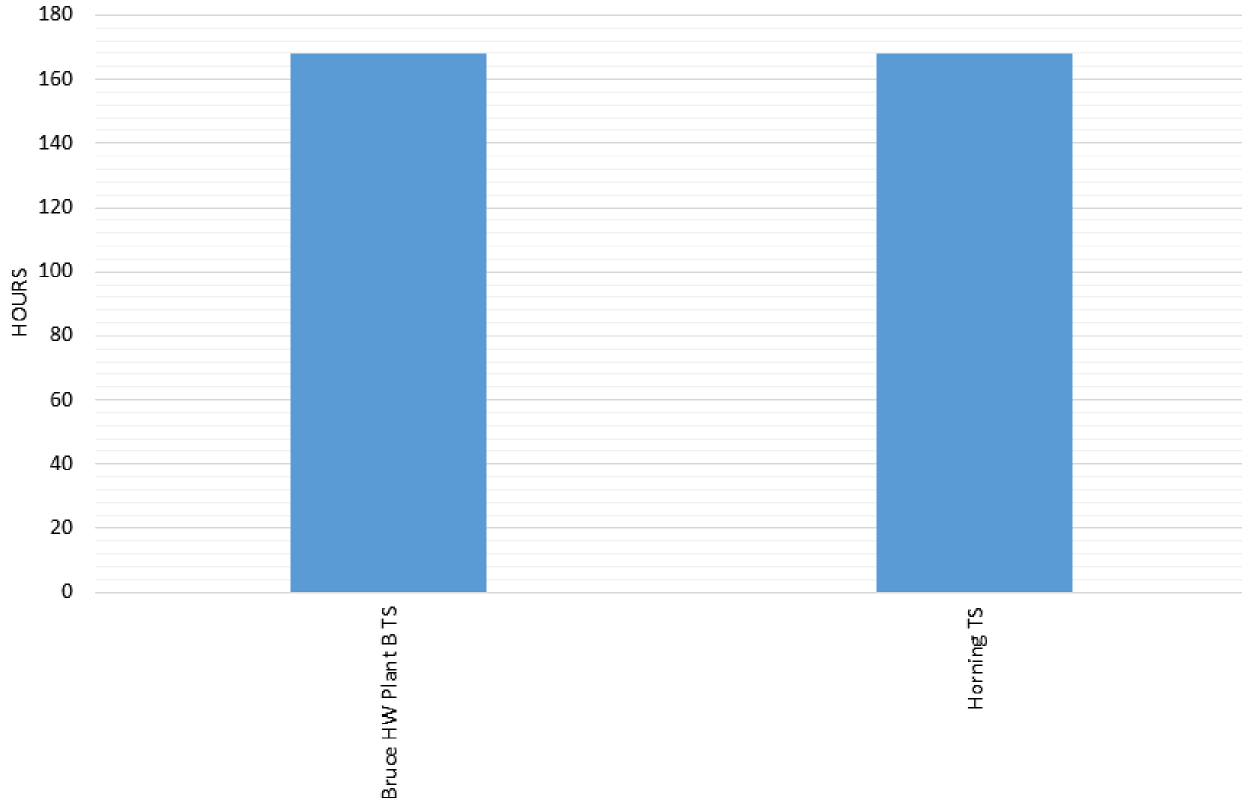


Figure 3-23
100 MVA 230/14-14 kV Inputs – Transportation Time from Spare Depot to Substation

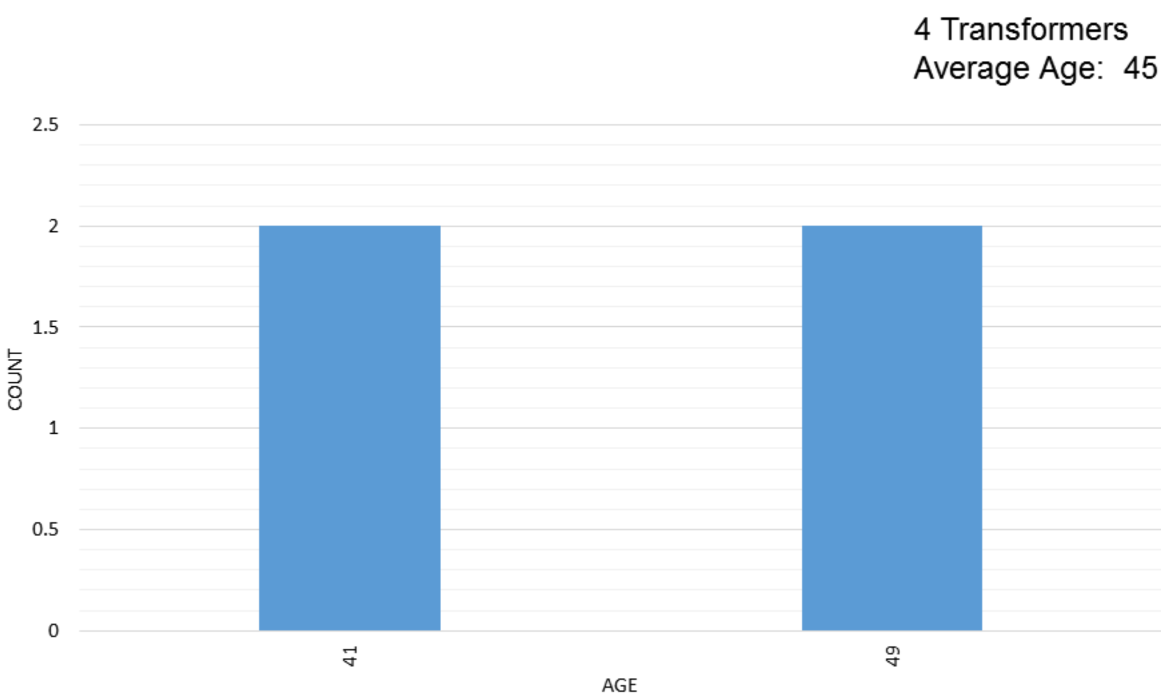


Figure 3-24
100 MVA 230/14-14 kV Inputs –Transformer Age Demographics

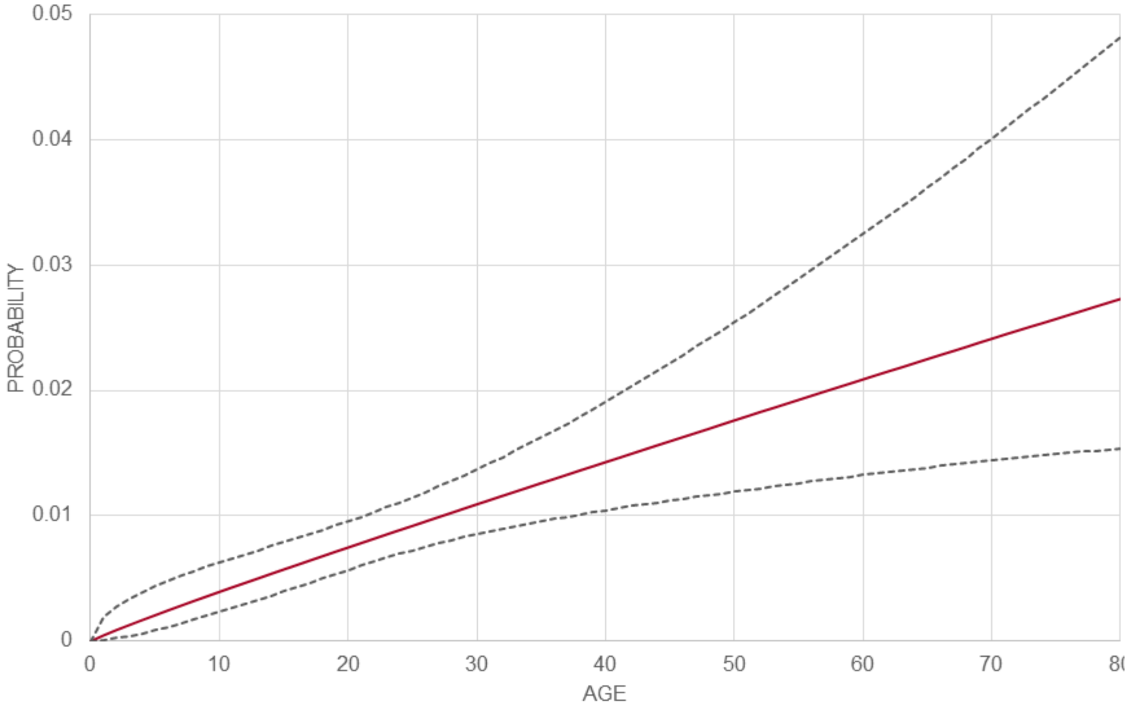
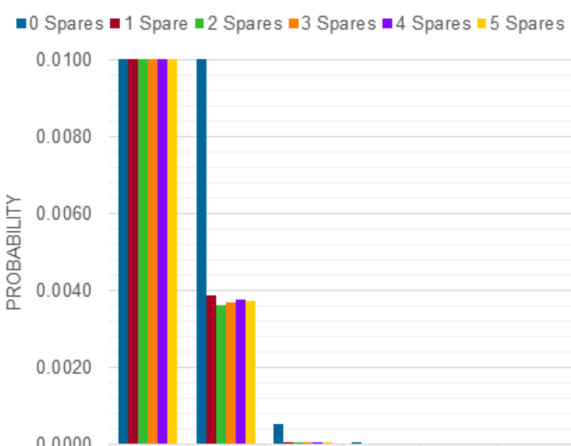


Figure 3-25
100 MVA 230/14-14 kV Inputs – Hazard Function

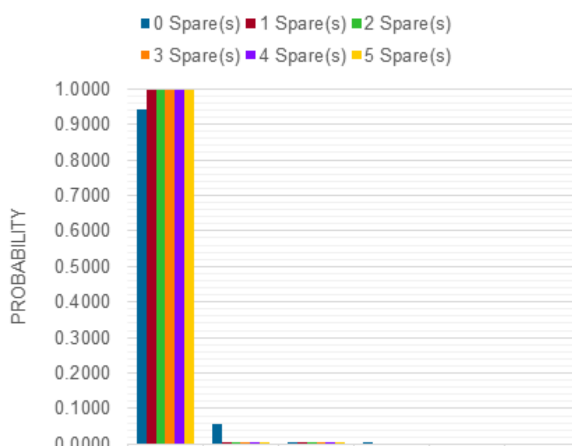
Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that all positions are available for all days?



	0	1	2	3	4	5
0 Spares	0.9830	0.0164	0.0005	0.0000	0.0000	0.0000
1 Spare	0.9961	0.0039	0.0000	0.0000	0.0000	0.0000
2 Spares	0.9964	0.0036	0.0000	0.0000	0.0000	0.0000
3 Spares	0.9963	0.0037	0.0000	0.0000	0.0000	0.0000
4 Spares	0.9962	0.0038	0.0000	0.0000	0.0000	0.0000
5 Spares	0.9963	0.0037	0.0000	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that the system is not at full availability at any time?



	0	1	2	3	4	5
0 Spare(s)	0.9432	0.0552	0.0015	0.0000	0.0000	0.0000
1 Spare(s)	0.9956	0.0044	0.0000	0.0000	0.0000	0.0000
2 Spare(s)	0.9967	0.0033	0.0000	0.0000	0.0000	0.0000
3 Spare(s)	0.9966	0.0034	0.0000	0.0000	0.0000	0.0000
4 Spare(s)	0.9965	0.0035	0.0000	0.0000	0.0000	0.0000
5 Spare(s)	0.9966	0.0034	0.0000	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Figure 3-26
100 MVA 230/14-14 kV Results

250 MVA 230/115 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

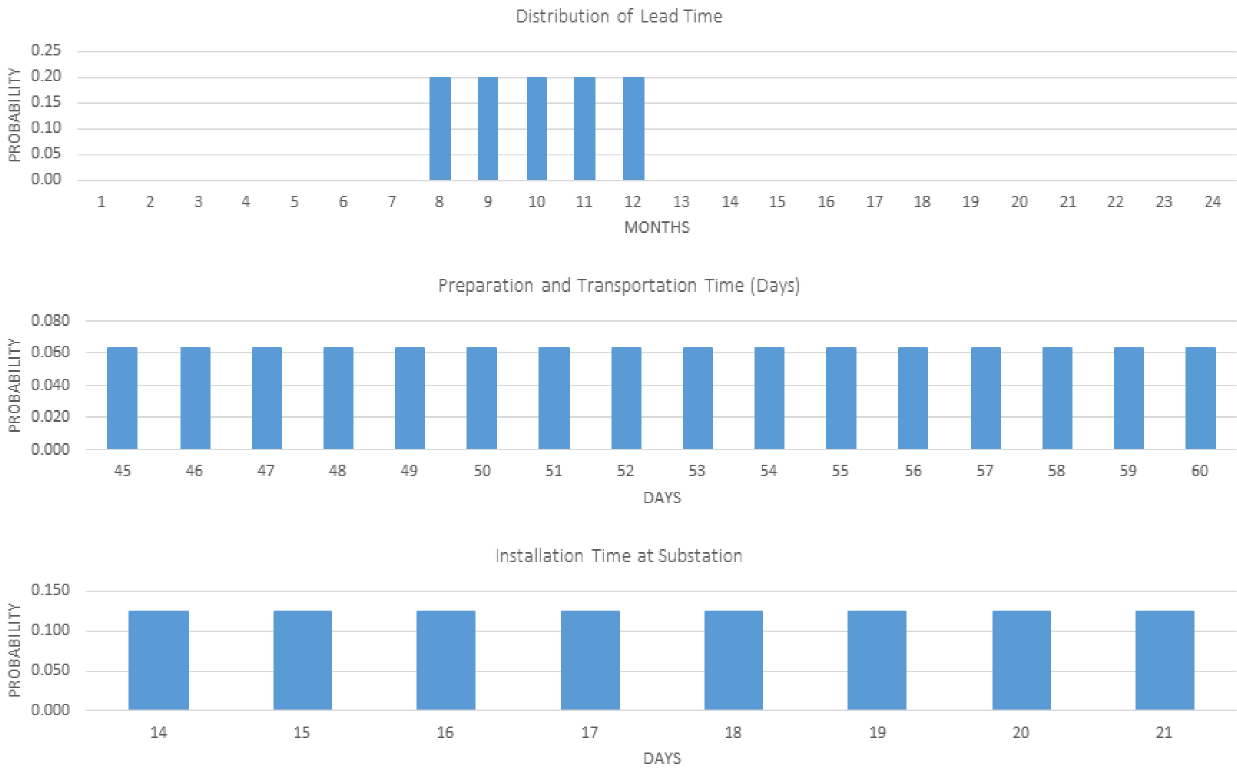


Figure 3-27
250 MVA 230/115 kV Inputs – Time Distributions

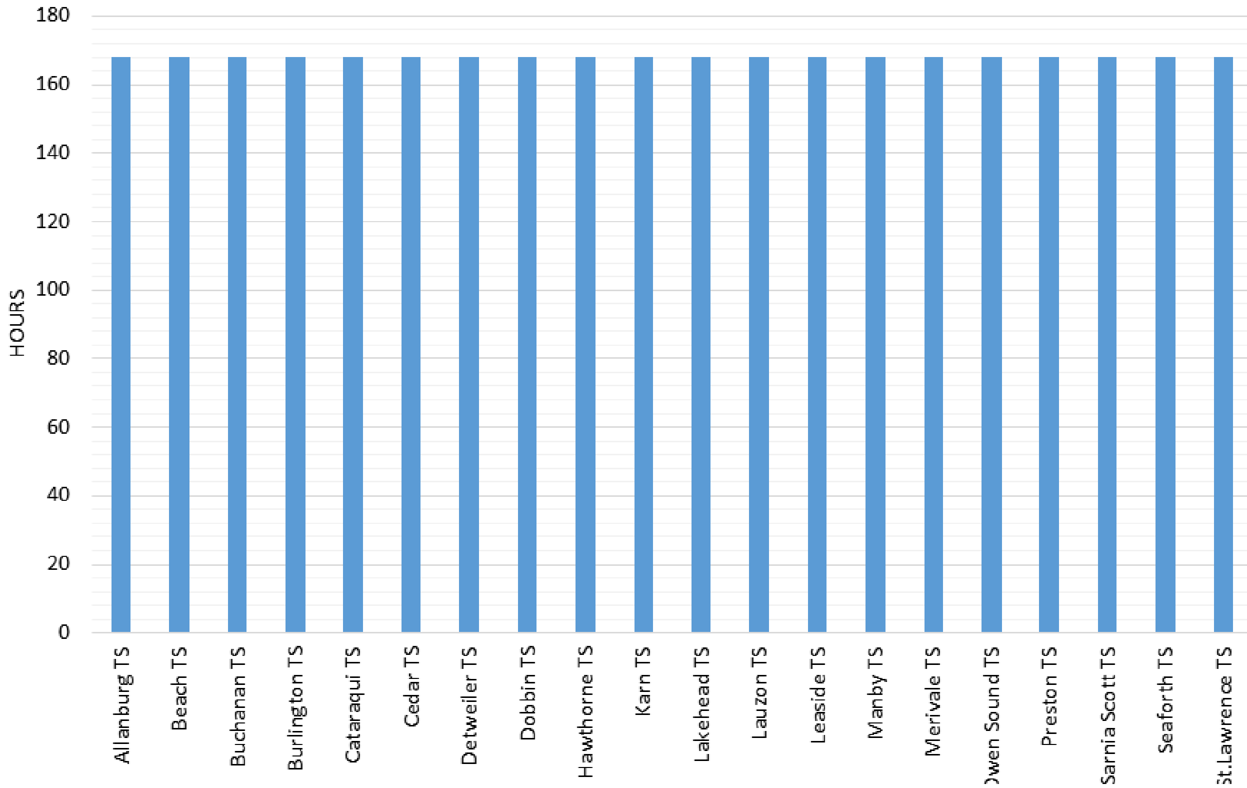


Figure 3-28
250 MVA 230/115 kV Inputs – Transportation Time from Spare Depot to Substation

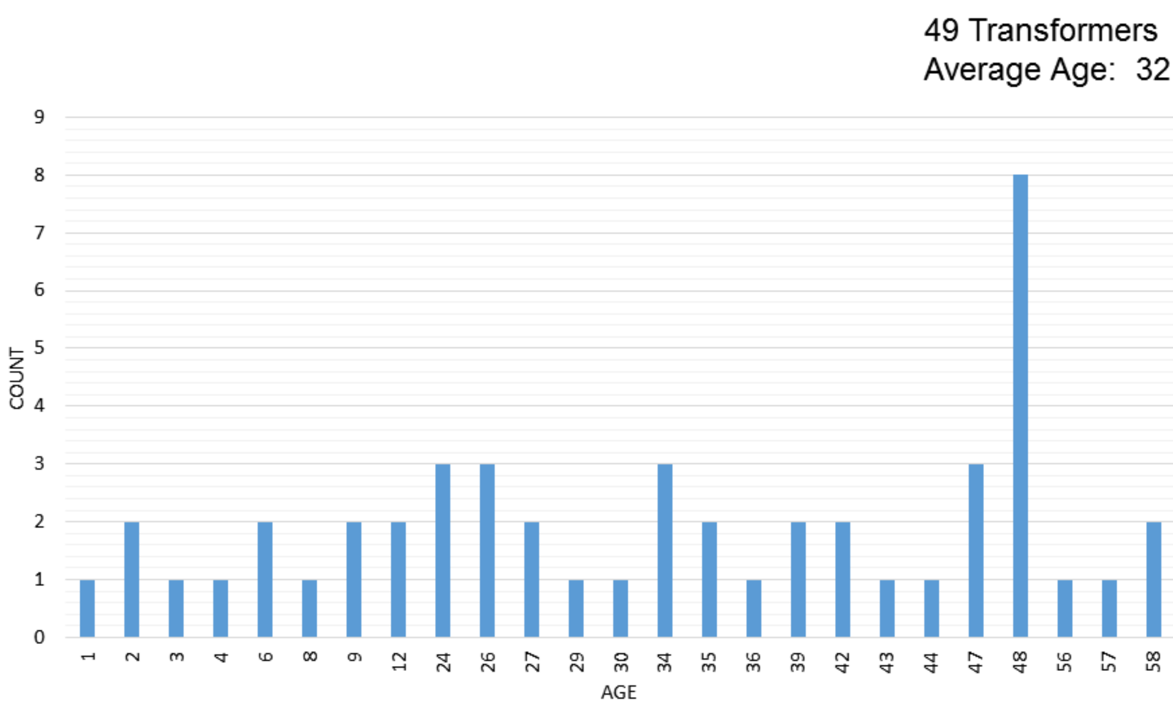


Figure 3-29
250 MVA 230/115 kV Inputs –Transformer Age Demographics

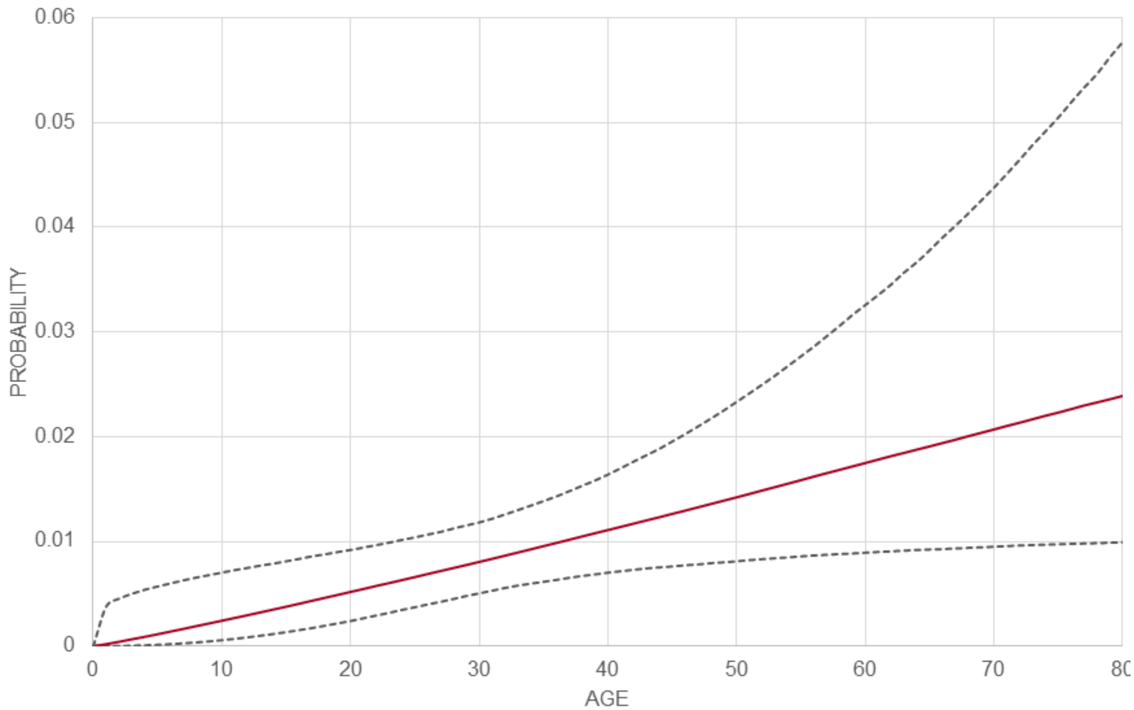
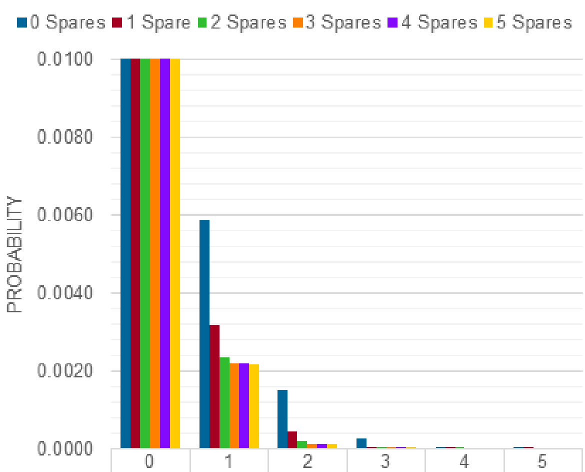


Figure 3-30
250 MVA 230/115 kV Inputs – Hazard Function

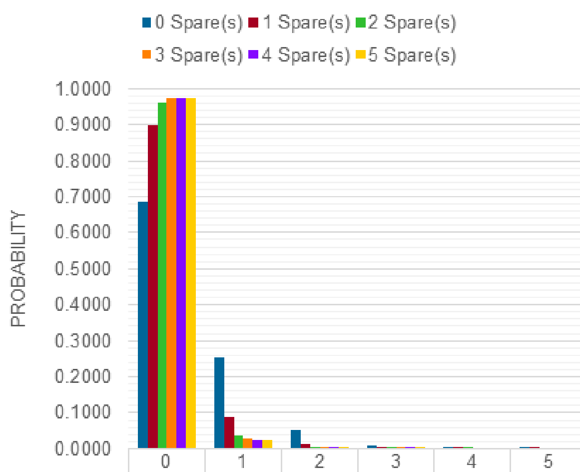
Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that all positions are available for all days?



	0	1	2	3	4	5
0 Spares	0.9923	0.0059	0.0015	0.0003	0.0000	0.0000
1 Spare	0.9963	0.0032	0.0005	0.0001	0.0000	0.0000
2 Spares	0.9974	0.0024	0.0002	0.0000	0.0000	0.0000
3 Spares	0.9977	0.0022	0.0001	0.0000	0.0000	0.0000
4 Spares	0.9977	0.0022	0.0001	0.0000	0.0000	0.0000
5 Spares	0.9977	0.0022	0.0001	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that the system is not at full availability at any time?



	0	1	2	3	4	5
0 Spare(s)	0.6841	0.2536	0.0539	0.0075	0.0008	0.0001
1 Spare(s)	0.8984	0.0873	0.0125	0.0017	0.0001	0.0000
2 Spare(s)	0.9603	0.0371	0.0023	0.0003	0.0000	0.0000
3 Spare(s)	0.9718	0.0277	0.0005	0.0000	0.0000	0.0000
4 Spare(s)	0.9727	0.0269	0.0004	0.0000	0.0000	0.0000
5 Spare(s)	0.9732	0.0263	0.0004	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Figure 3-31
250 MVA 230/115 kV Results

125 MVA 230/115 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

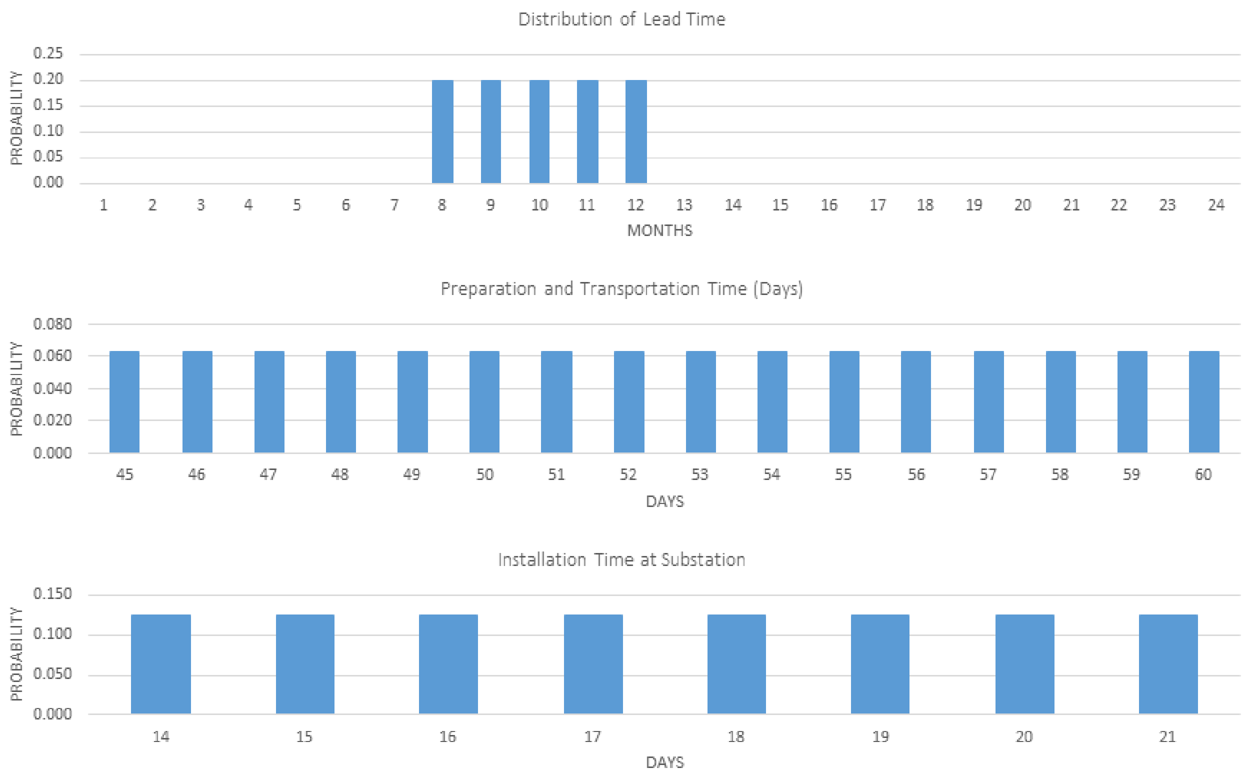


Figure 3-32
125 MVA 230/115 kV Inputs – Time Distributions

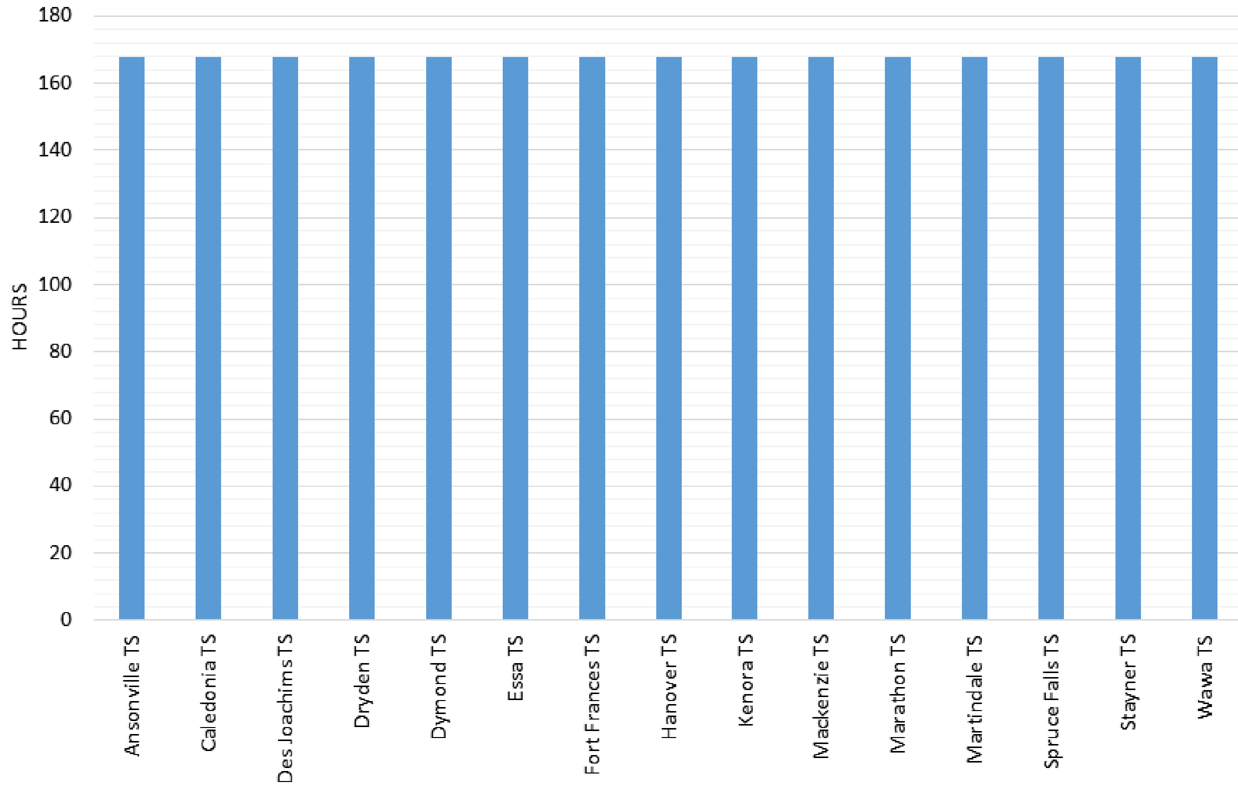


Figure 3-33
125 MVA 230/115 kV Inputs –Transportation Time from Spare Depot to Substation

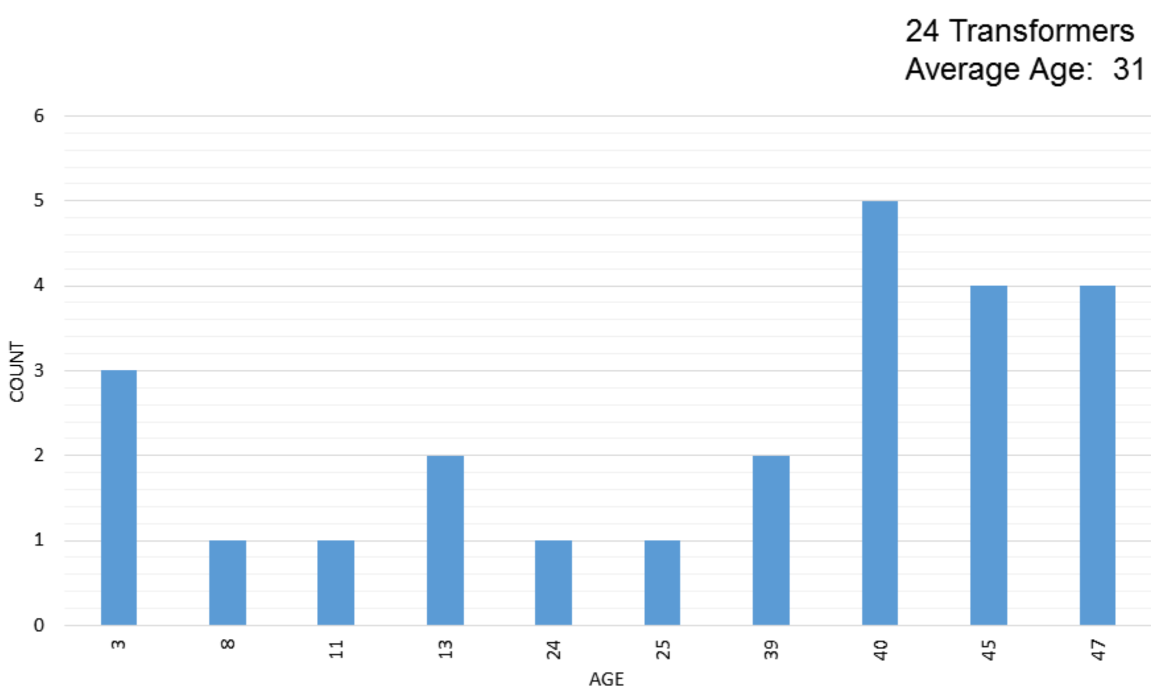


Figure 3-34
125 MVA 230/115 kV Inputs – Transformer Age Demographics

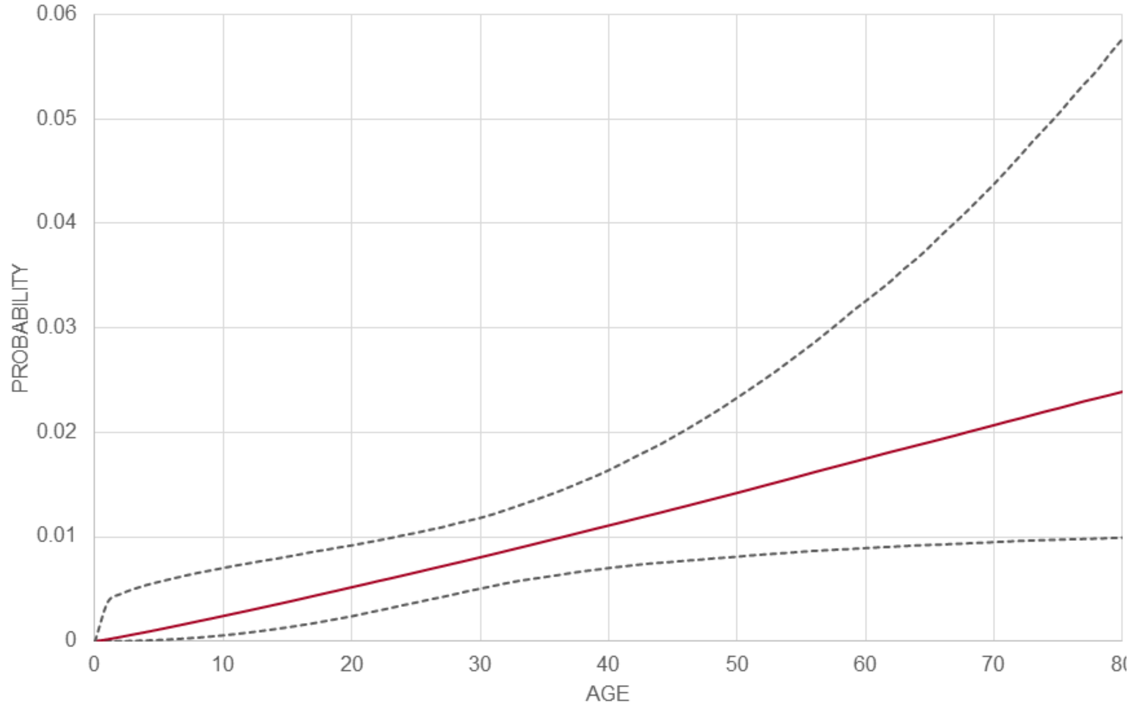
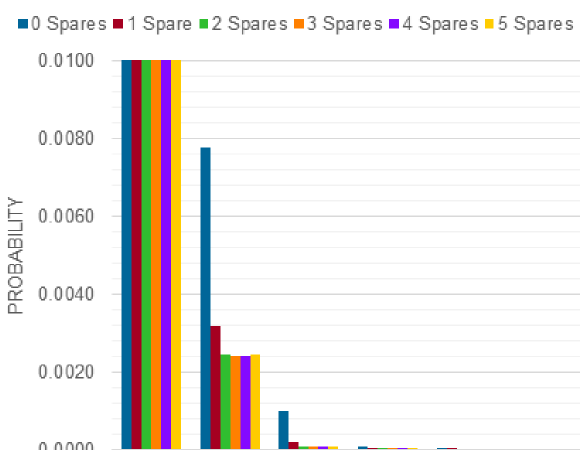


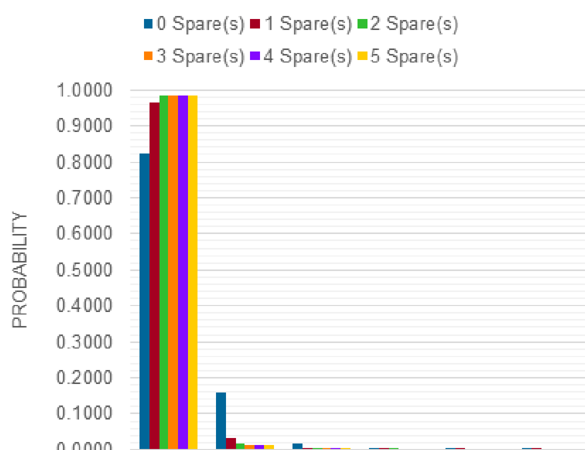
Figure 3-35
125 MVA 230/115 kV Inputs – Hazard Function

Minimum Thresholdtime for Counting Unavailable Position: 60 Days
What is the probability that all positions are available for all days?



	0	1	2	3	4	5
0 Spares	0.9911	0.0078	0.0010	0.0001	0.0000	0.0000
1 Spare	0.9966	0.0032	0.0002	0.0000	0.0000	0.0000
2 Spares	0.9975	0.0024	0.0001	0.0000	0.0000	0.0000
3 Spares	0.9975	0.0024	0.0001	0.0000	0.0000	0.0000
4 Spares	0.9975	0.0024	0.0001	0.0000	0.0000	0.0000
5 Spares	0.9975	0.0024	0.0001	0.0000	0.0000	0.0000

Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that the system is not at full availability at any time?



	0	1	2	3	4	5
0 Spare(s)	0.8249	0.1572	0.0167	0.0011	0.0001	0.0000
1 Spare(s)	0.9634	0.0345	0.0020	0.0001	0.0000	0.0000
2 Spare(s)	0.9843	0.0155	0.0003	0.0000	0.0000	0.0000
3 Spare(s)	0.9860	0.0139	0.0001	0.0000	0.0000	0.0000
4 Spare(s)	0.9861	0.0138	0.0001	0.0000	0.0000	0.0000
5 Spare(s)	0.9860	0.0139	0.0001	0.0000	0.0000	0.0000

Figure 3-36
125 MVA 230/115 kV Results

75 MVA 115/14-14 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

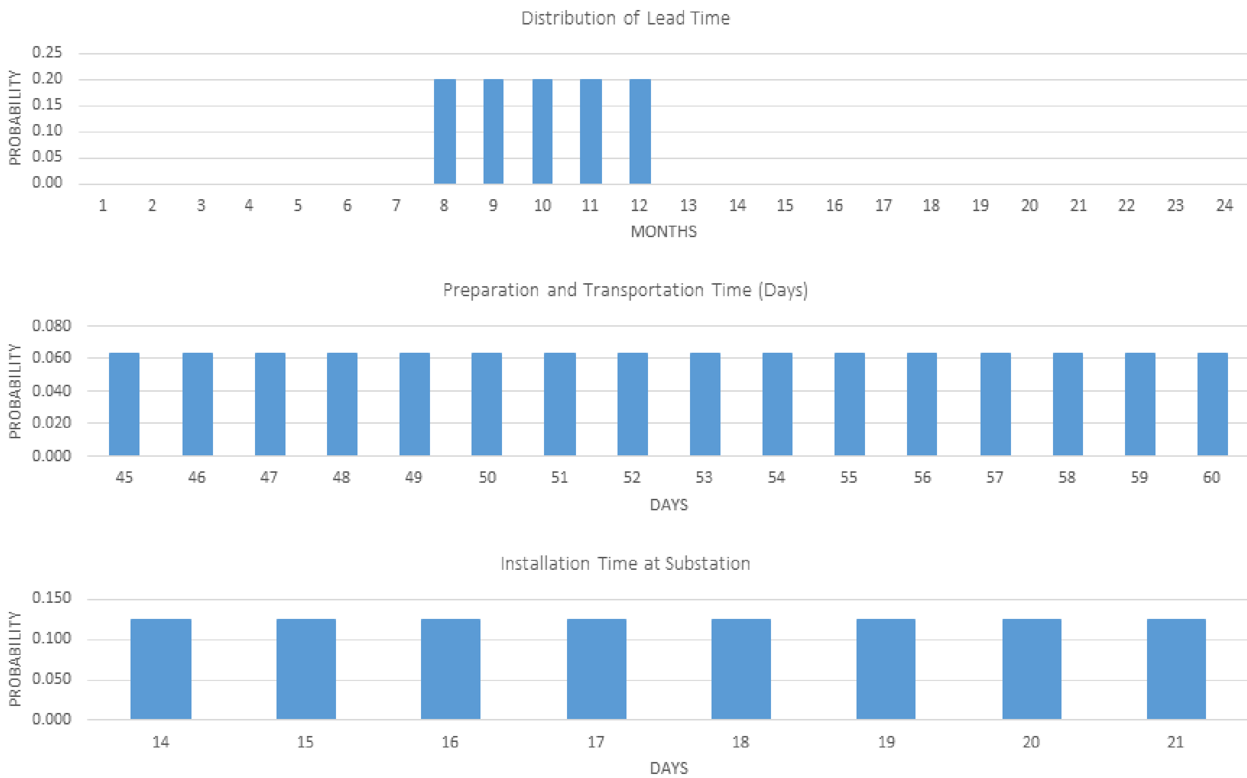


Figure 3-37
75 MVA 115/14-14 kV Inputs – Time Distributions

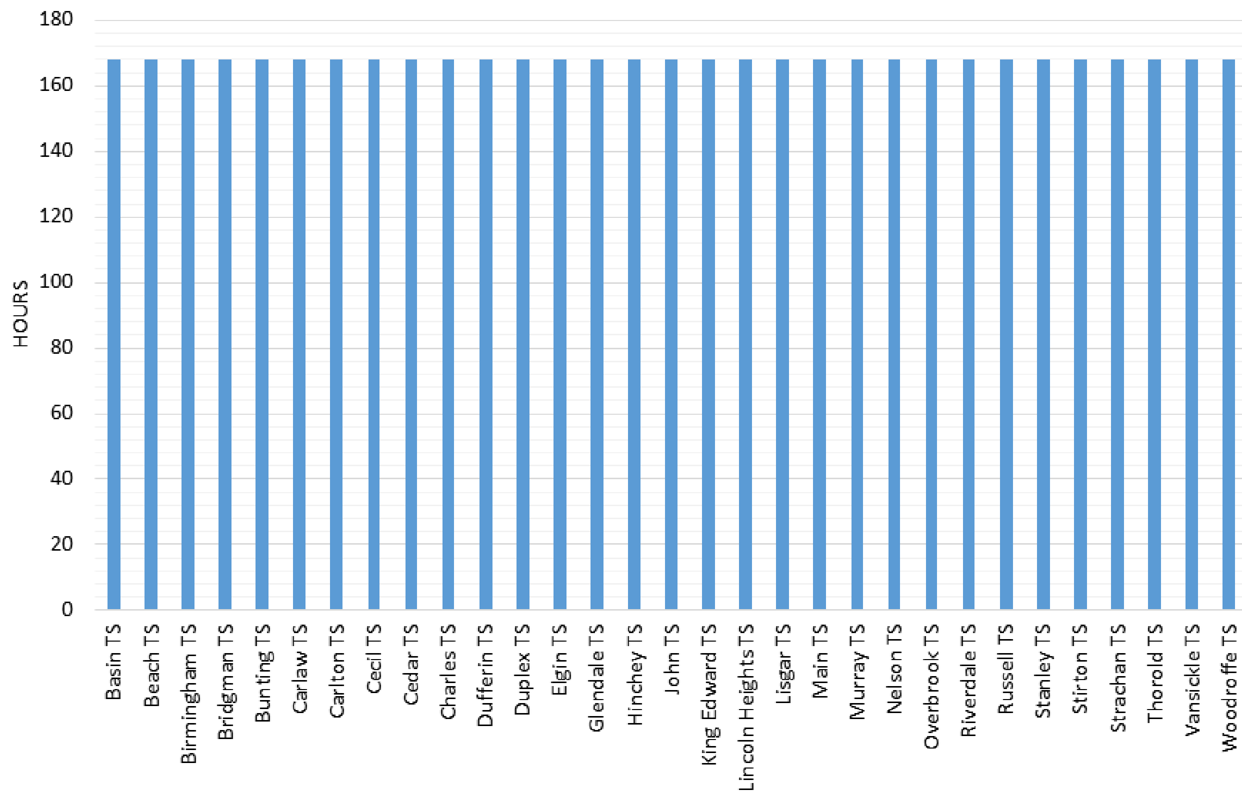


Figure 3-38
75 MVA 115/14-14 kV Inputs – Transportation Time from Spare Depot to Substation

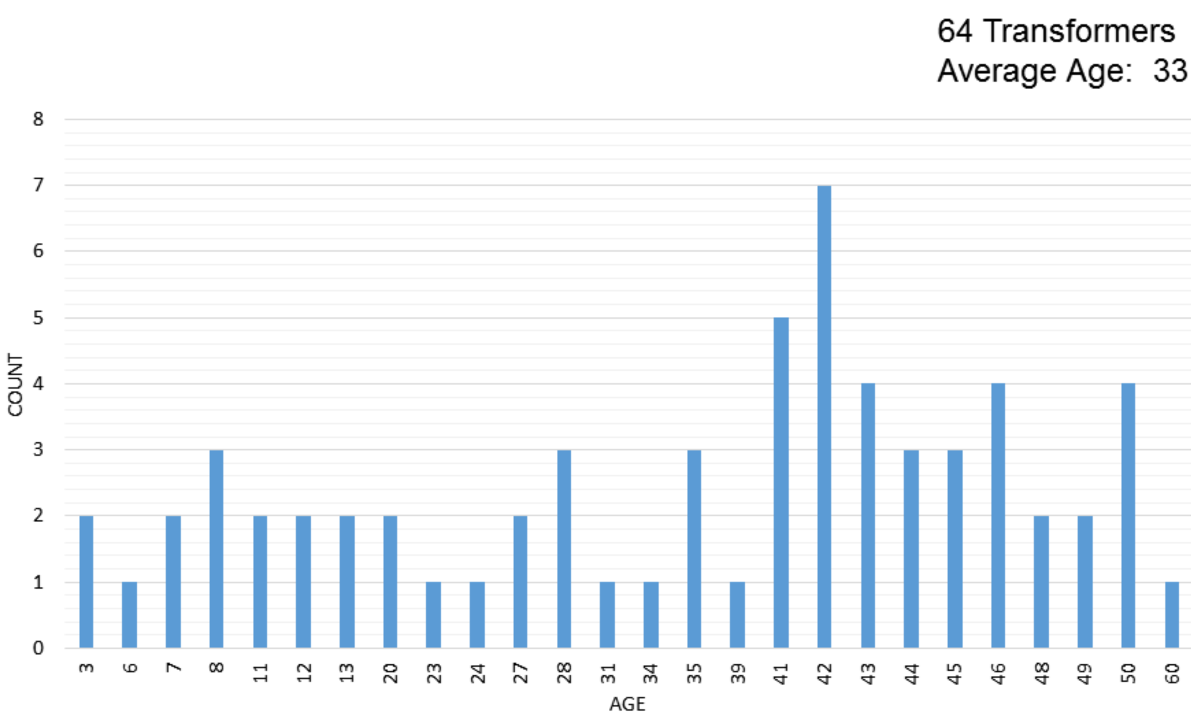


Figure 3-39
75 MVA 115/14-14 kV Inputs – Transformer Age Demographics

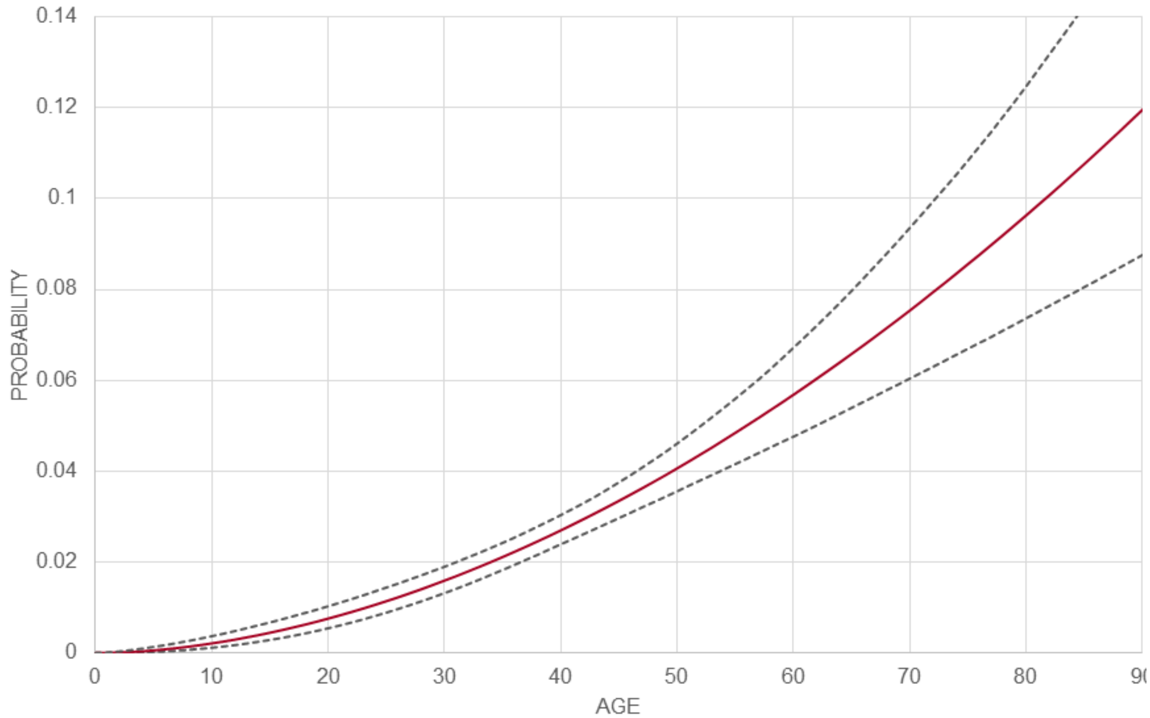
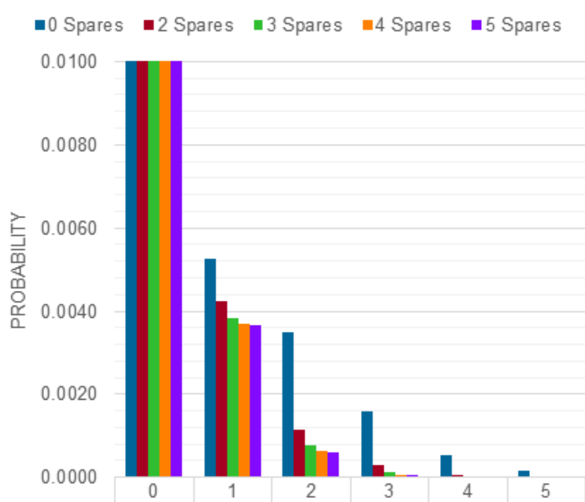


Figure 3-40
75 MVA 115/14-14 kV Inputs – Hazard Function

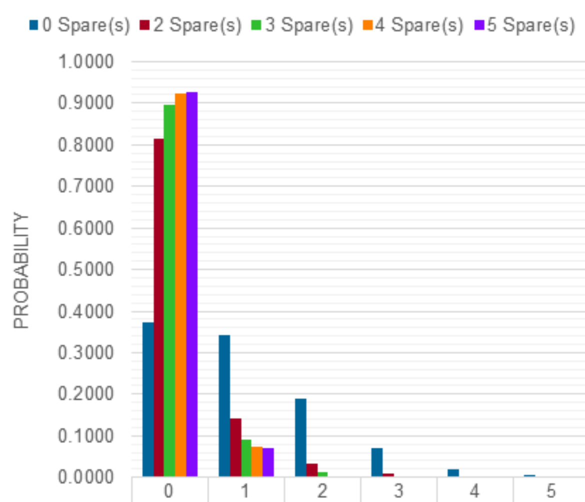
Minimum Thresholdtime for Counting Unavailable Position: 60 Days
What is the probability that all positions are available for all days?



	0	1	2	3	4	5
0 Spares	0.9890	0.0053	0.0035	0.0016	0.0005	0.0001
2 Spares	0.9943	0.0042	0.0012	0.0003	0.0001	0.0000
3 Spares	0.9953	0.0038	0.0008	0.0001	0.0000	0.0000
4 Spares	0.9956	0.0037	0.0006	0.0001	0.0000	0.0000
5 Spares	0.9957	0.0037	0.0006	0.0001	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that the system is not at full availability at any time?



	0	1	2	3	4	5
0 Spare(s)	0.3732	0.3416	0.1897	0.0710	0.0203	0.0043
2 Spare(s)	0.8131	0.1419	0.0341	0.0088	0.0018	0.0003
3 Spare(s)	0.8948	0.0916	0.0112	0.0020	0.0003	0.0001
4 Spare(s)	0.9217	0.0736	0.0042	0.0004	0.0001	0.0000
5 Spare(s)	0.9277	0.0693	0.0029	0.0001	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Figure 3-41
75 MVA 115/14-14 kV Results

42MVA 115/14 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

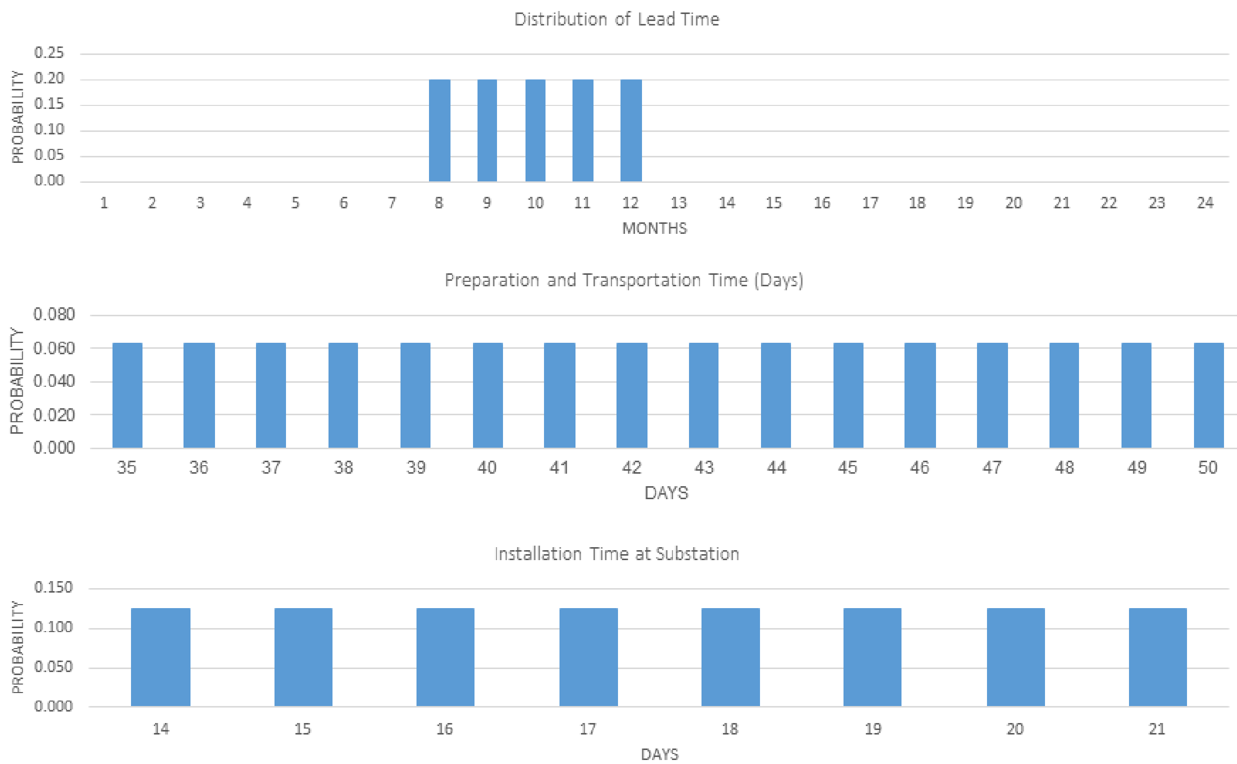


Figure 3-42
42MVA 115/14 kV Inputs – Time Distributions

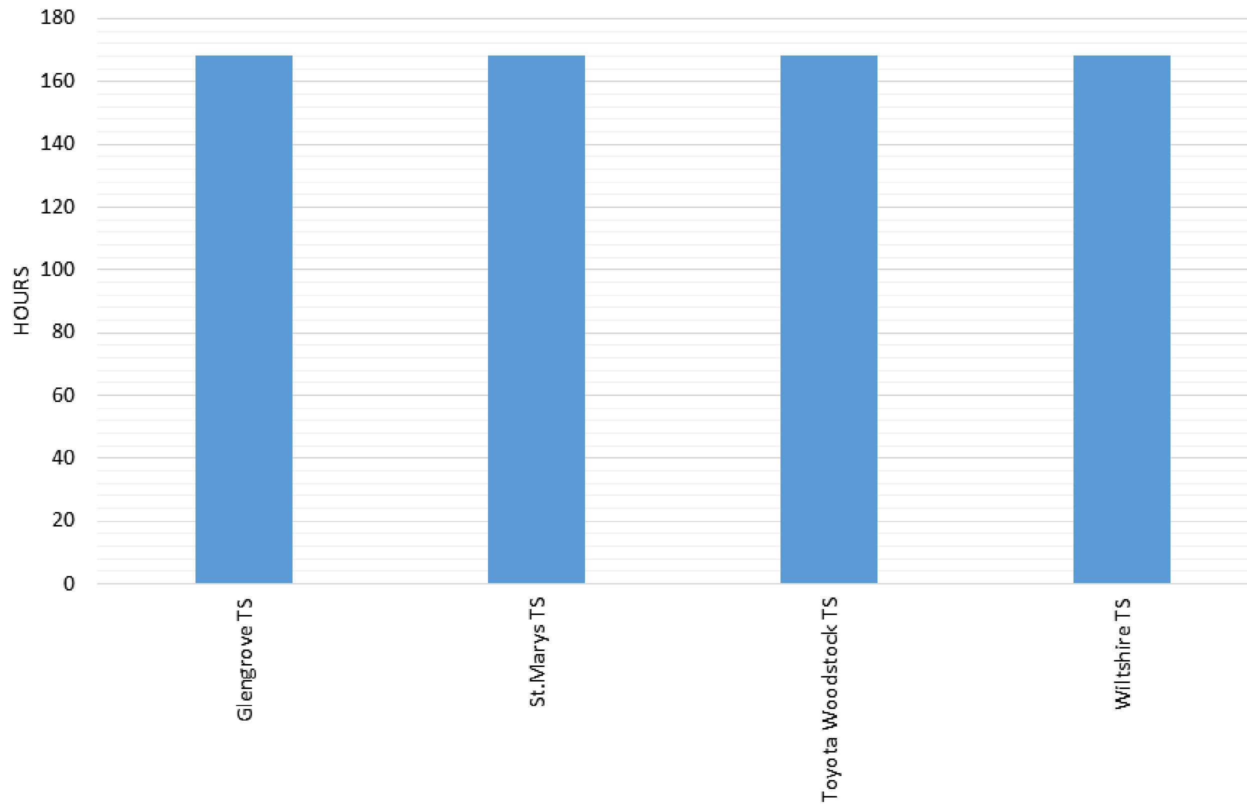


Figure 3-43
42MVA 115/14 kV Inputs – Transportation Time from Spare Depot to Substation

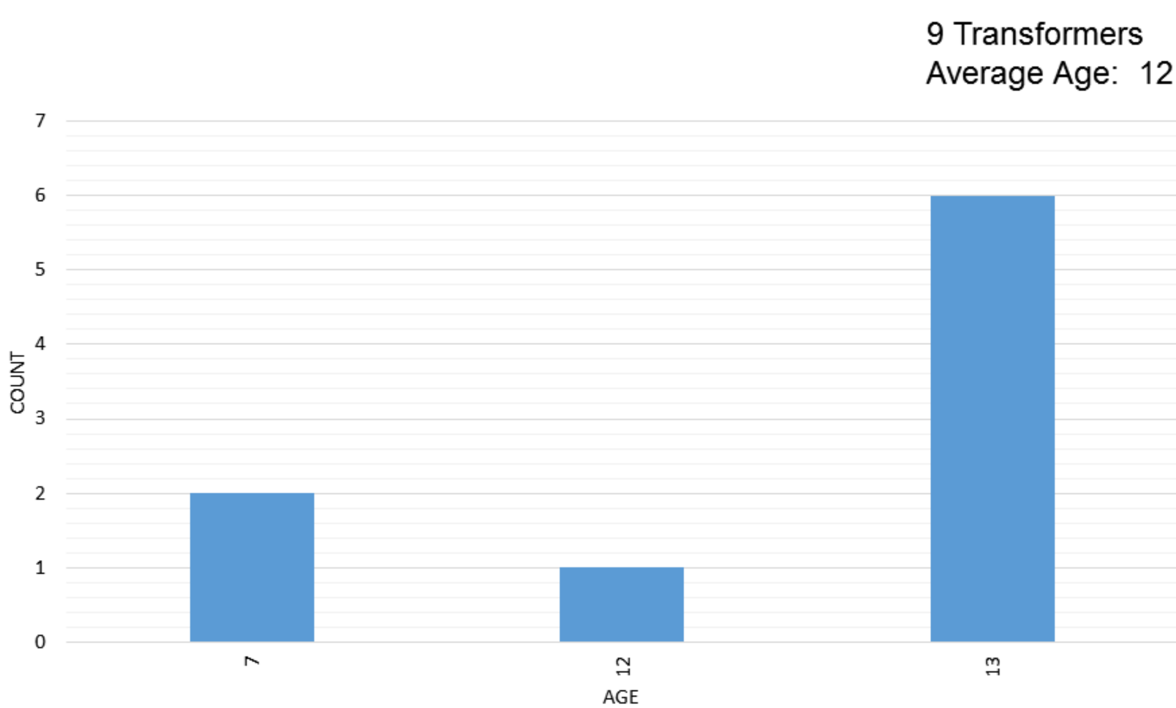


Figure 3-44
42MVA 115/14 kV Inputs – Transformer Age Demographics

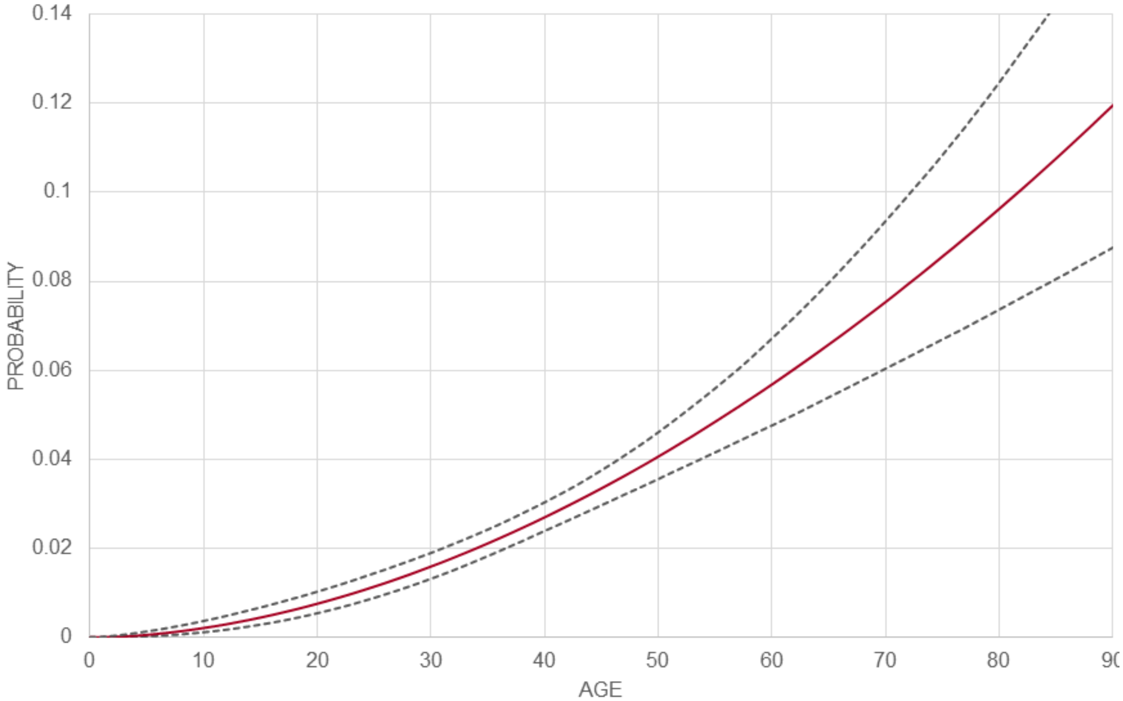
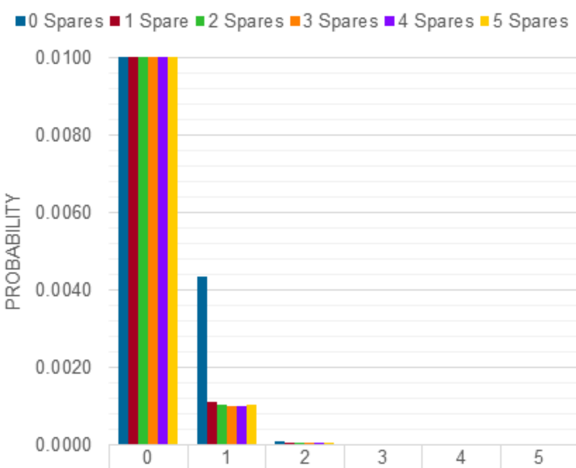


Figure 3-45
42MVA 115/14 kV Inputs – Hazard Function

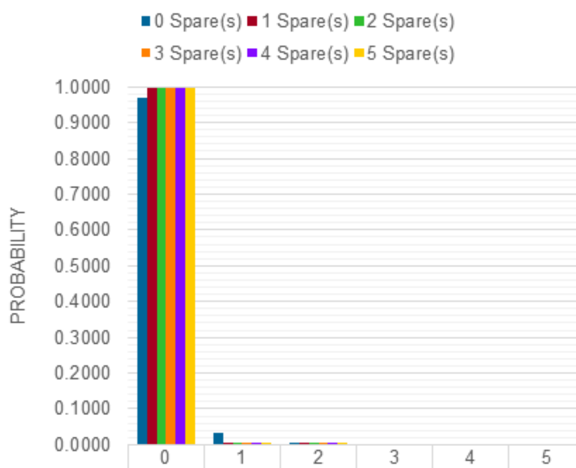
Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that all positions are available for all days?



	0	1	2	3	4	5
0 Spares	0.9956	0.0044	0.0001	0.0000	0.0000	0.0000
1 Spare	0.9989	0.0011	0.0000	0.0000	0.0000	0.0000
2 Spares	0.9990	0.0010	0.0000	0.0000	0.0000	0.0000
3 Spares	0.9990	0.0010	0.0000	0.0000	0.0000	0.0000
4 Spares	0.9990	0.0010	0.0000	0.0000	0.0000	0.0000
5 Spares	0.9990	0.0010	0.0000	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that the system is not at full availability at any time?



	0	1	2	3	4	5
0 Spare(s)	0.9679	0.0317	0.0004	0.0000	0.0000	0.0000
1 Spare(s)	0.9977	0.0023	0.0000	0.0000	0.0000	0.0000
2 Spare(s)	0.9985	0.0015	0.0000	0.0000	0.0000	0.0000
3 Spare(s)	0.9985	0.0015	0.0000	0.0000	0.0000	0.0000
4 Spare(s)	0.9985	0.0015	0.0000	0.0000	0.0000	0.0000
5 Spare(s)	0.9984	0.0016	0.0000	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Figure 3-46
42MVA 115/14 kV Results

42MVA 115/28 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

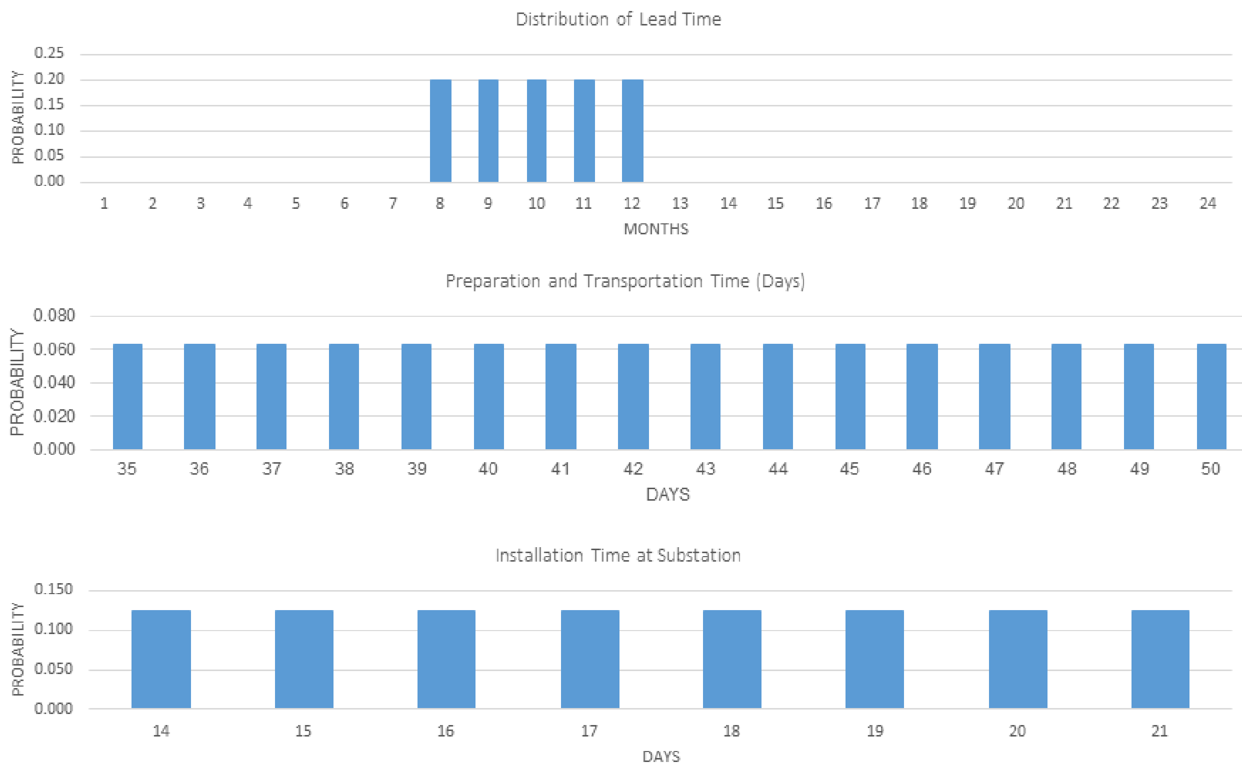


Figure 3-47
42MVA 115/28 kV Inputs – Time Distributions

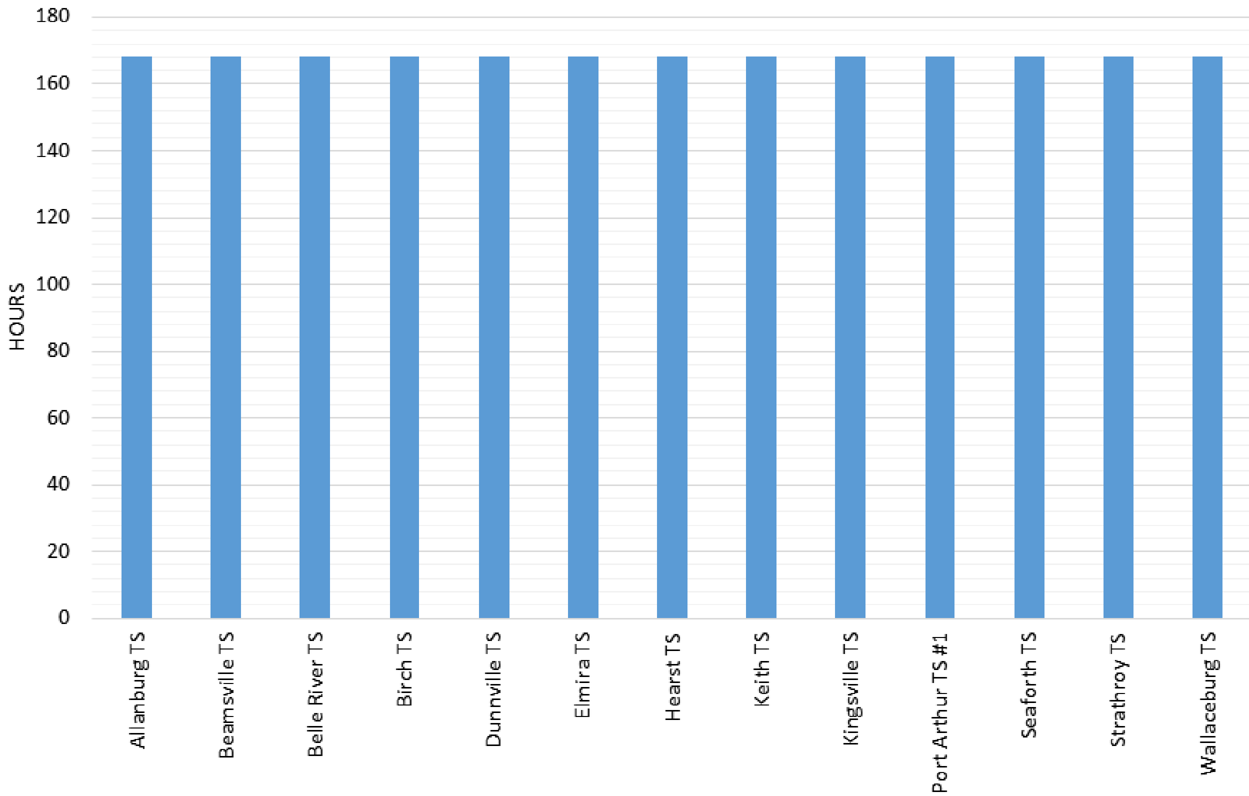


Figure 3-48
42MVA 115/28 kV Inputs – Transportation Time from Spare Depot to Substation

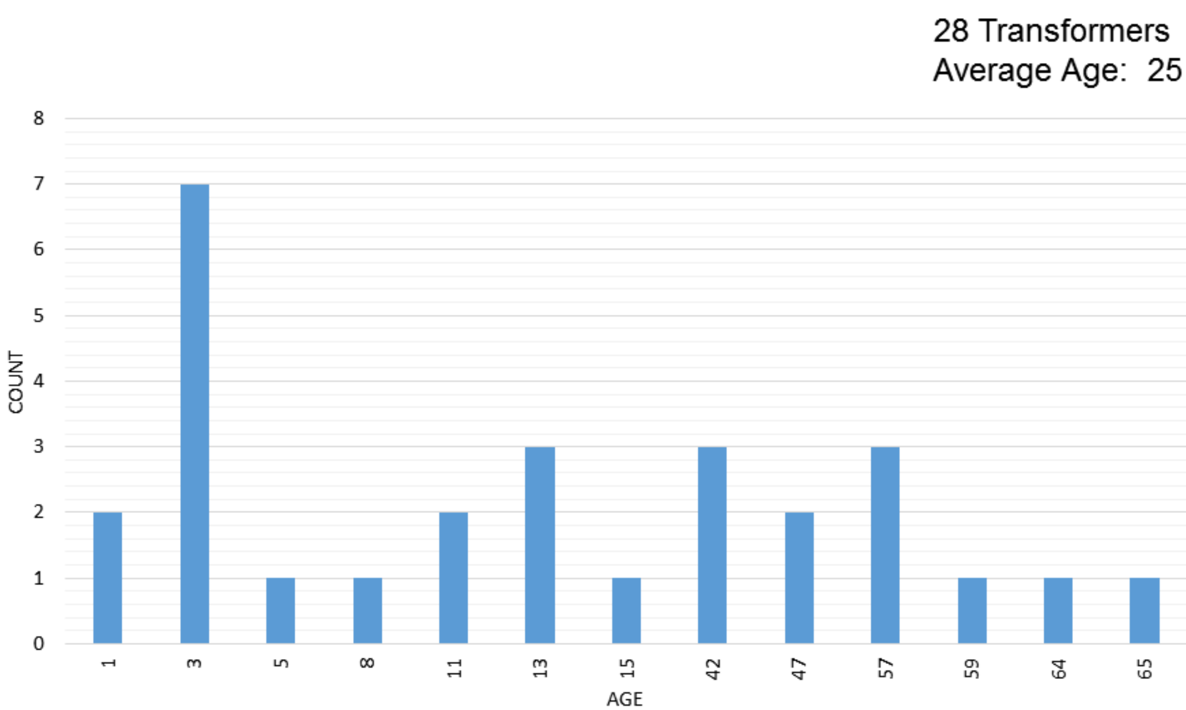


Figure 3-49
42MVA 115/28 kV Inputs – Transformer Age Demographics

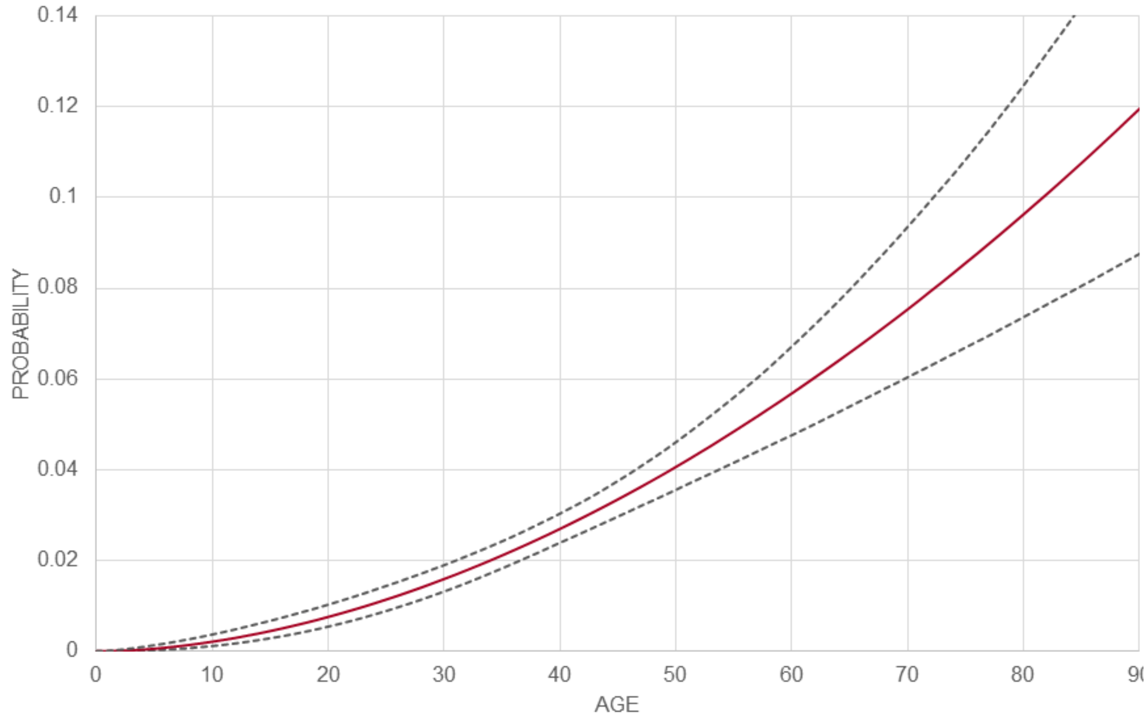
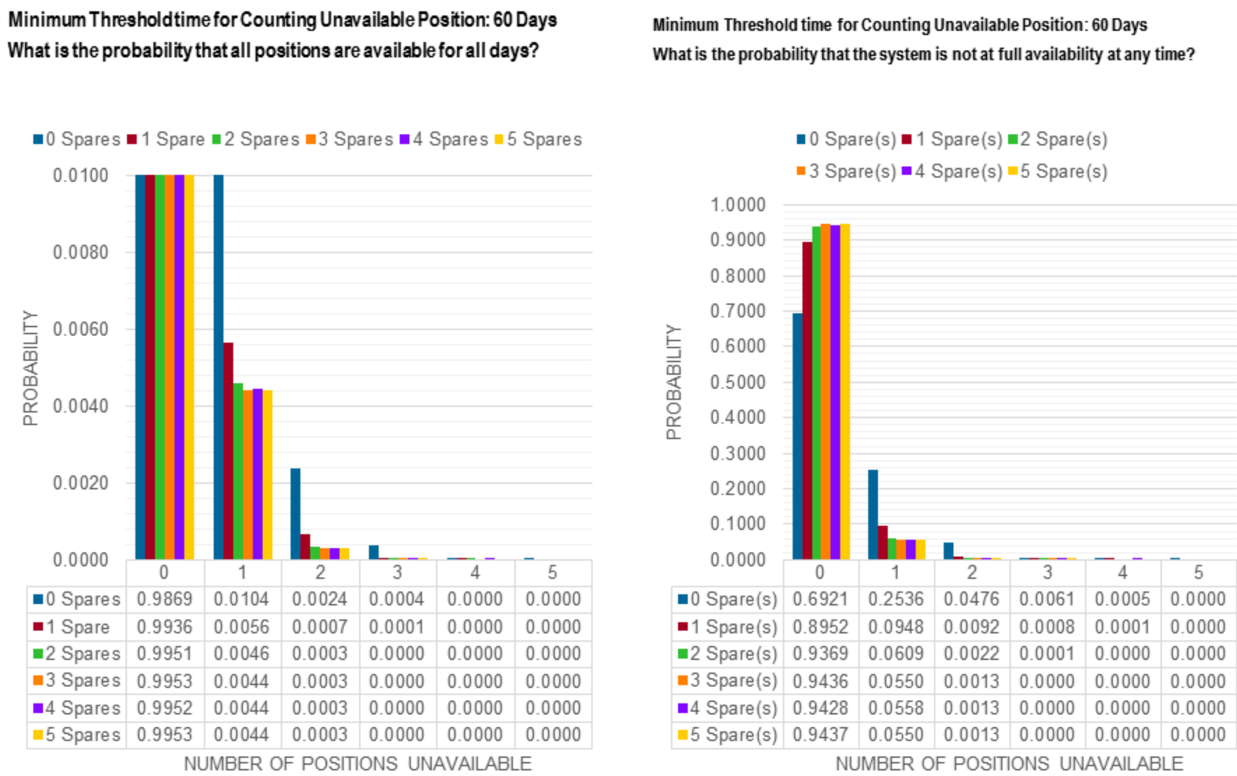


Figure 3-50
42MVA 115/28 kV Inputs – Hazard Function



	0	1	2	3	4	5
0 Spares	0.9869	0.0104	0.0024	0.0004	0.0000	0.0000
1 Spare	0.9936	0.0056	0.0007	0.0001	0.0000	0.0000
2 Spares	0.9951	0.0046	0.0003	0.0000	0.0000	0.0000
3 Spares	0.9953	0.0044	0.0003	0.0000	0.0000	0.0000
4 Spares	0.9952	0.0044	0.0003	0.0000	0.0000	0.0000
5 Spares	0.9953	0.0044	0.0003	0.0000	0.0000	0.0000

	0	1	2	3	4	5
0 Spare(s)	0.6921	0.2536	0.0476	0.0061	0.0005	0.0000
1 Spare(s)	0.8952	0.0948	0.0092	0.0008	0.0001	0.0000
2 Spare(s)	0.9369	0.0609	0.0022	0.0001	0.0000	0.0000
3 Spare(s)	0.9436	0.0550	0.0013	0.0000	0.0000	0.0000
4 Spare(s)	0.9428	0.0558	0.0013	0.0000	0.0000	0.0000
5 Spare(s)	0.9437	0.0550	0.0013	0.0000	0.0000	0.0000

Figure 3-51
42MVA 115/28 kV Results

83MVA 115/28 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

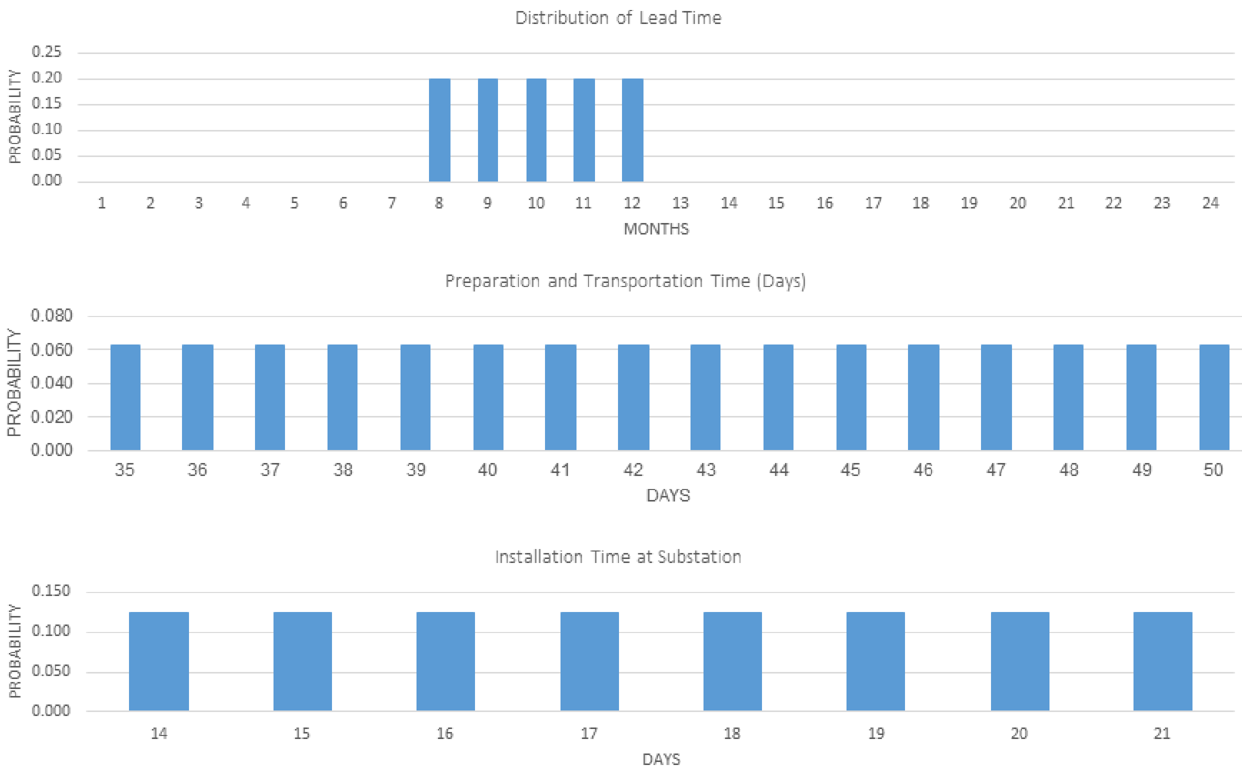


Figure 3-52
83MVA 115/28 kV Inputs – Time Distributions

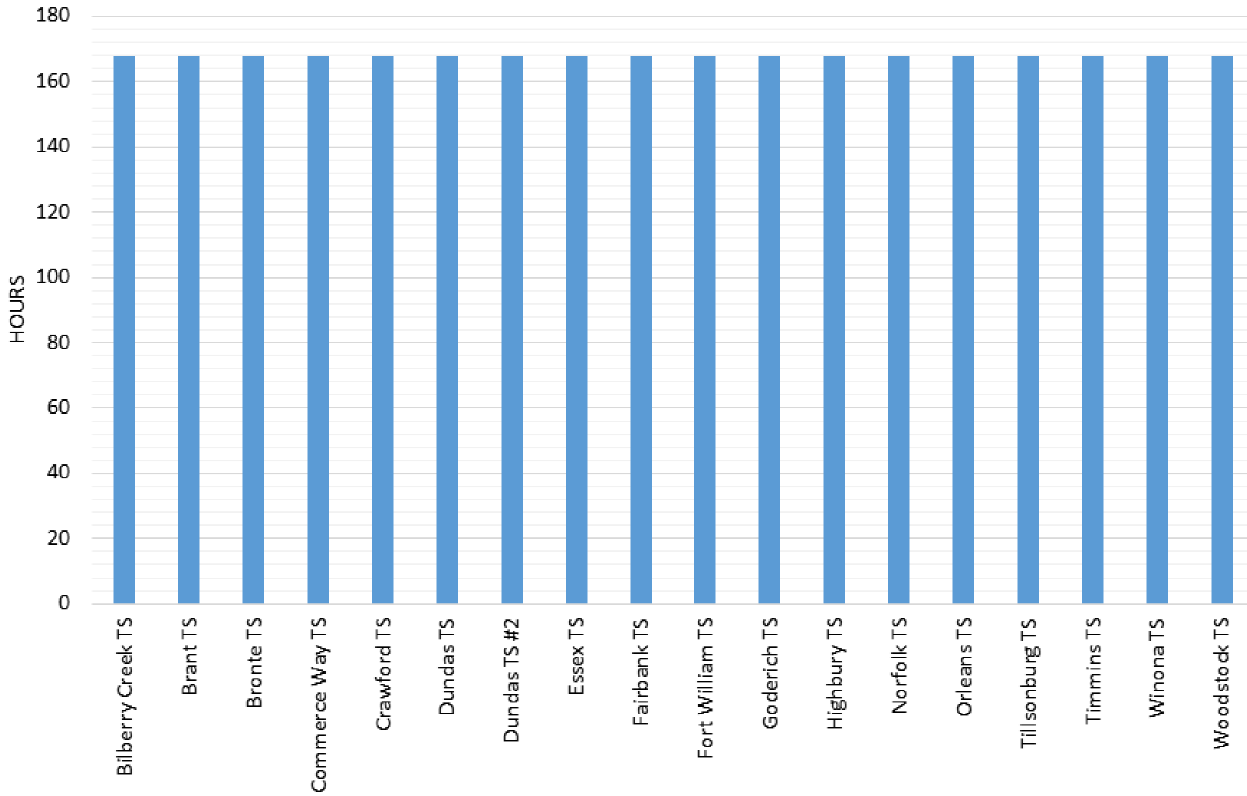


Figure 3-53
83MVA 115/28 kV Inputs – Transportation Time from Spare Depot to Substation

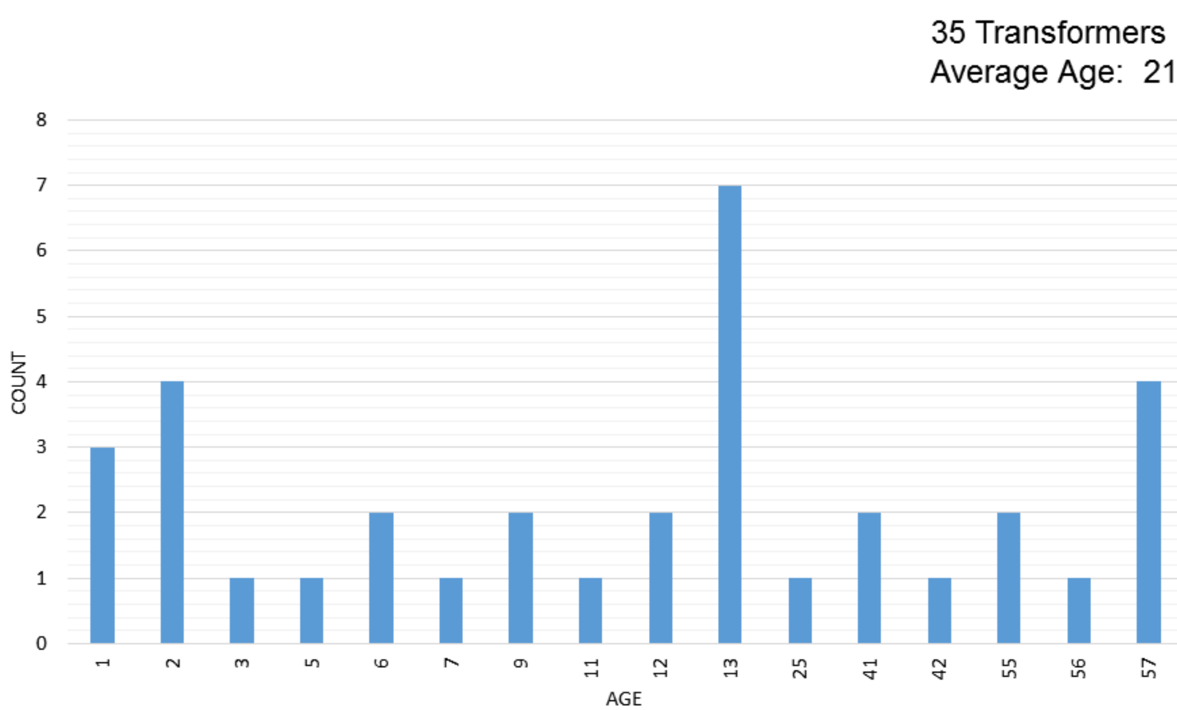


Figure 3-54
83MVA 115/28 kV Inputs – Transformer Age Demographics

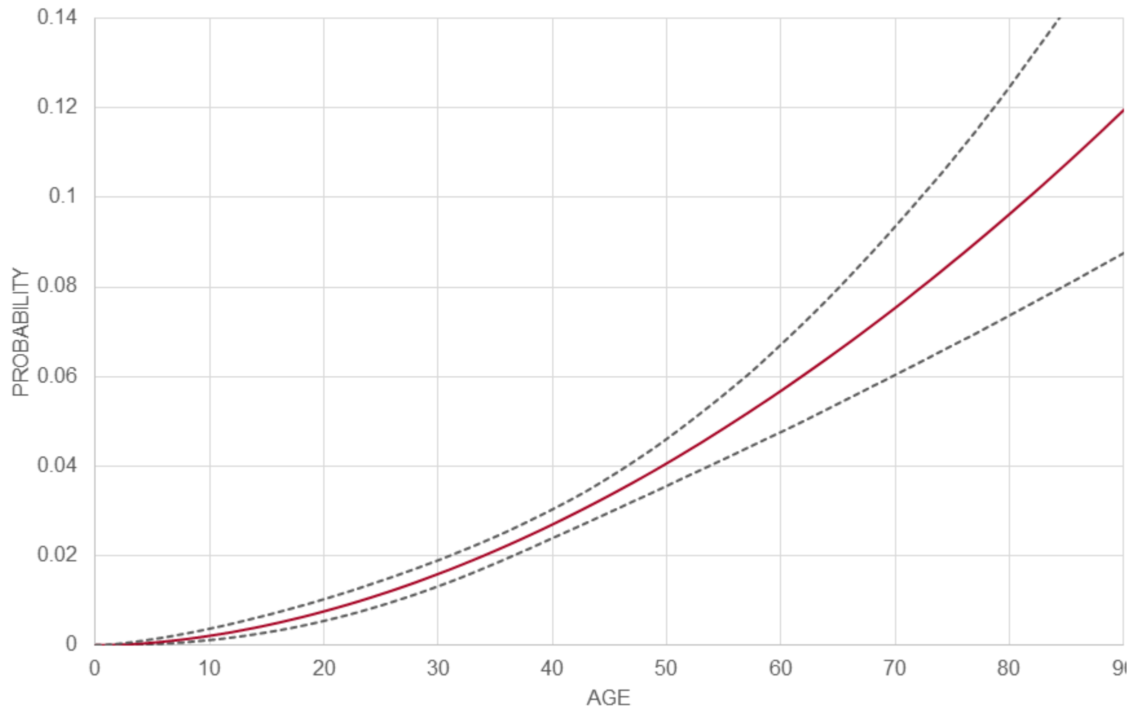
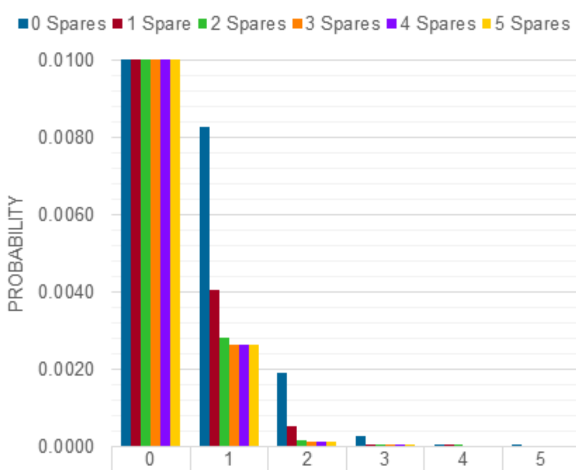


Figure 3-55
83MVA 115/28 kV Inputs – Hazard Function

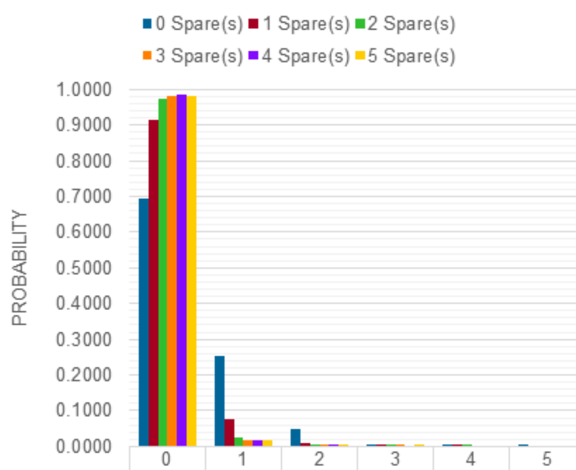
Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that all positions are available for all days?



	0	1	2	3	4	5
0 Spares	0.9895	0.0083	0.0019	0.0003	0.0000	0.0000
1 Spare	0.9954	0.0041	0.0005	0.0001	0.0000	0.0000
2 Spares	0.9970	0.0028	0.0002	0.0000	0.0000	0.0000
3 Spares	0.9972	0.0026	0.0001	0.0000	0.0000	0.0000
4 Spares	0.9973	0.0026	0.0001	0.0000	0.0000	0.0000
5 Spares	0.9973	0.0026	0.0001	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that the system is not at full availability at any time?



	0	1	2	3	4	5
0 Spare(s)	0.6922	0.2534	0.0482	0.0056	0.0004	0.0001
1 Spare(s)	0.9139	0.0754	0.0096	0.0010	0.0001	0.0000
2 Spare(s)	0.9735	0.0253	0.0011	0.0001	0.0000	0.0000
3 Spare(s)	0.9822	0.0177	0.0001	0.0000	0.0000	0.0000
4 Spare(s)	0.9830	0.0168	0.0002	0.0000	0.0000	0.0000
5 Spare(s)	0.9829	0.0170	0.0001	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Figure 3-56
83MVA 115/28 kV Results

42 MVA 115/44 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

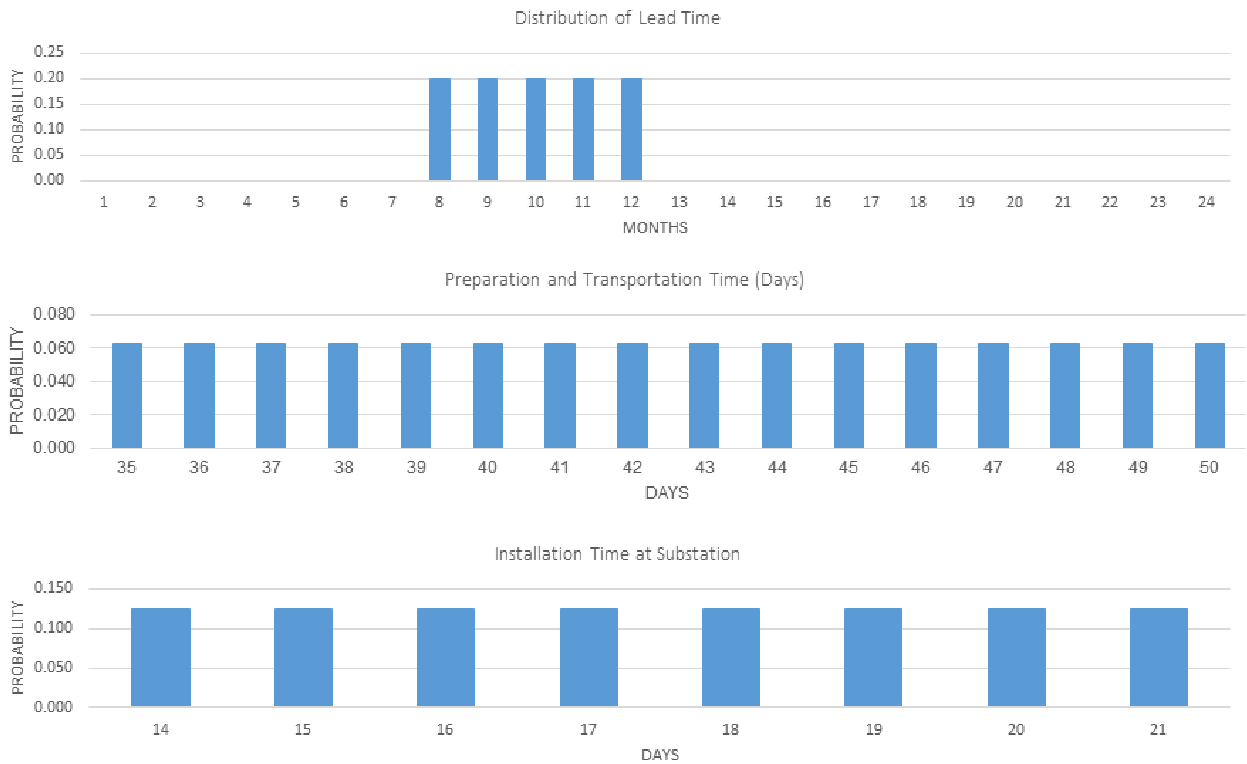


Figure 3-57
42 MVA 115/44 kV Inputs – Time Distributions

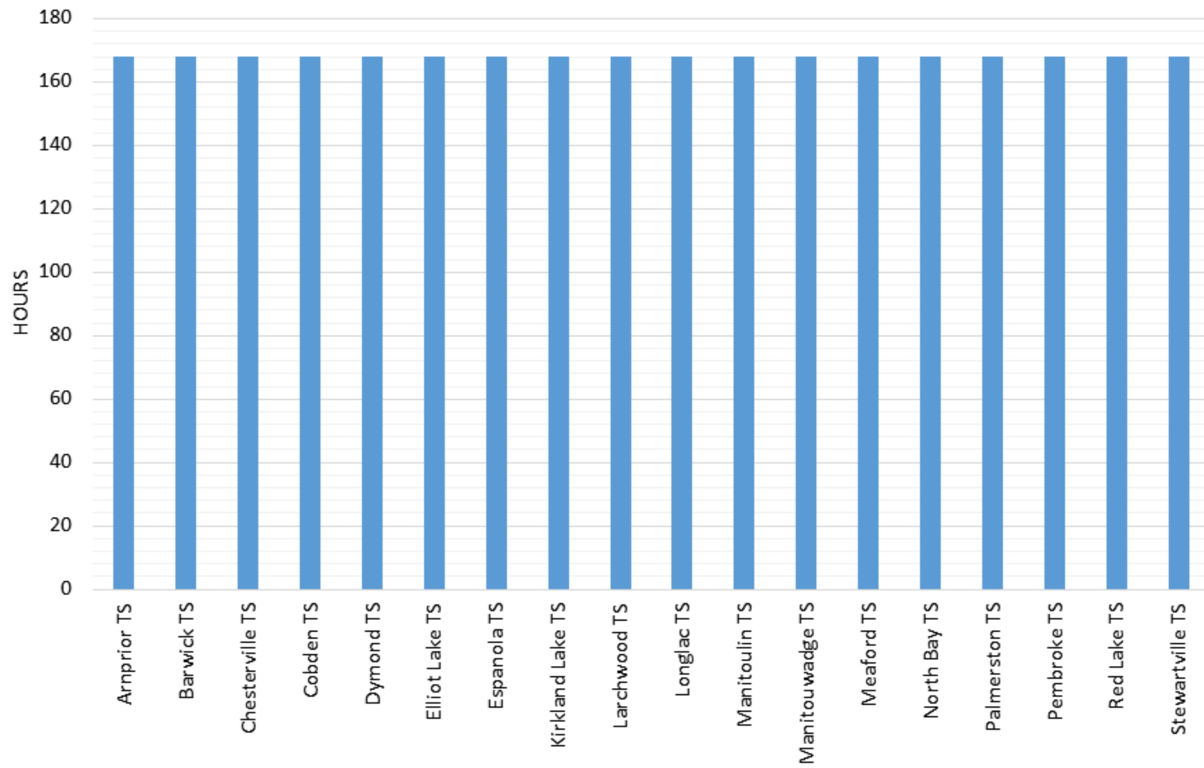


Figure 3-58
42 MVA 115/44 kV Inputs – Transportation Time from Spare Depot to Substation

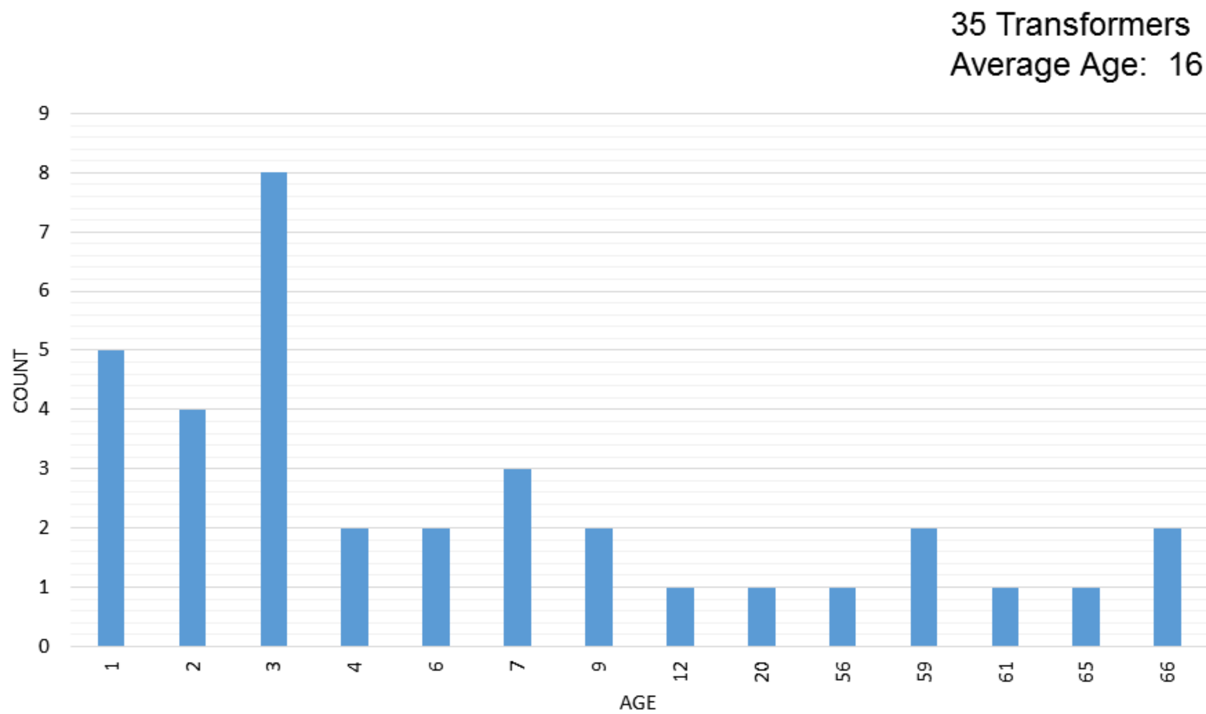


Figure 3-59
42 MVA 115/44 kV Inputs – Transformer Age Demographics

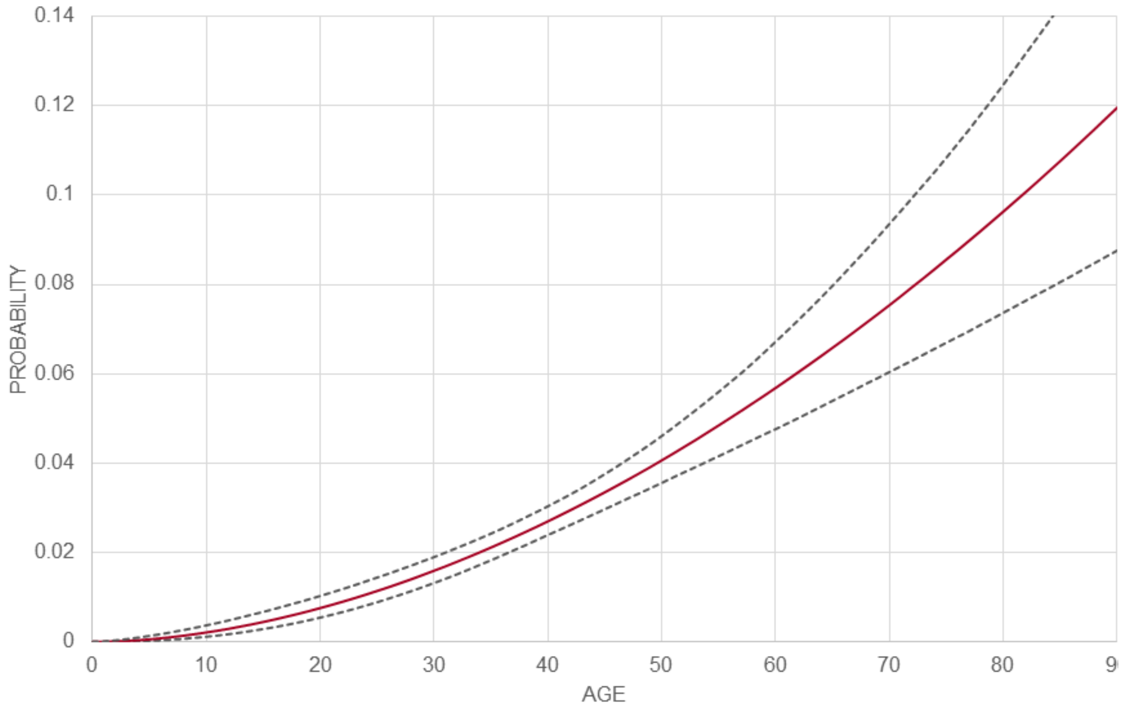
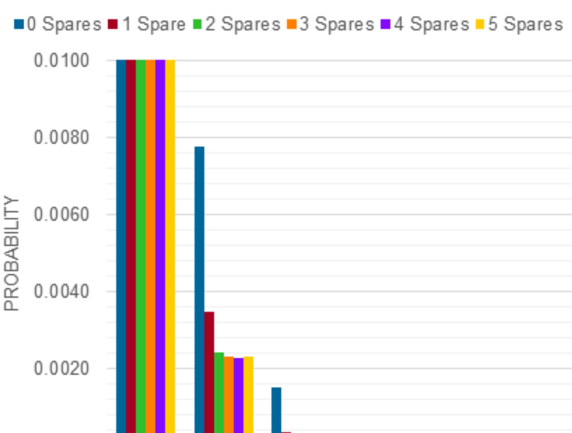


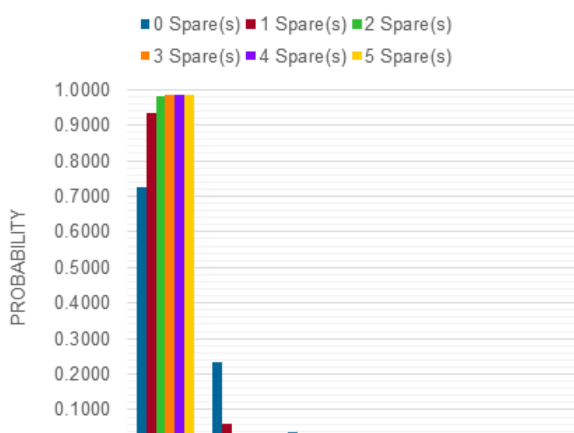
Figure 3-60
42 MVA 115/44 kV Inputs – Hazard Function

Minimum Thresholdtime for Counting Unavailable Position: 60 Days
What is the probability that all positions are available for all days?



	0	1	2	3	4	5
0 Spares	0.9905	0.0078	0.0015	0.0002	0.0000	0.0000
1 Spare	0.9962	0.0035	0.0003	0.0000	0.0000	0.0000
2 Spares	0.9975	0.0024	0.0001	0.0000	0.0000	0.0000
3 Spares	0.9976	0.0023	0.0001	0.0000	0.0000	0.0000
4 Spares	0.9976	0.0023	0.0001	0.0000	0.0000	0.0000
5 Spares	0.9976	0.0023	0.0001	0.0000	0.0000	0.0000

Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that the system is not at full availability at any time?



	0	1	2	3	4	5
0 Spare(s)	0.7238	0.2347	0.0374	0.0038	0.0003	0.0000
1 Spare(s)	0.9324	0.0611	0.0059	0.0005	0.0000	0.0000
2 Spare(s)	0.9801	0.0194	0.0004	0.0000	0.0000	0.0000
3 Spare(s)	0.9850	0.0149	0.0001	0.0000	0.0000	0.0000
4 Spare(s)	0.9854	0.0145	0.0001	0.0000	0.0000	0.0000
5 Spare(s)	0.9852	0.0147	0.0001	0.0000	0.0000	0.0000

Figure 3-61
42 MVA 115/44 kV Results

100 MVA 115/14-14 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

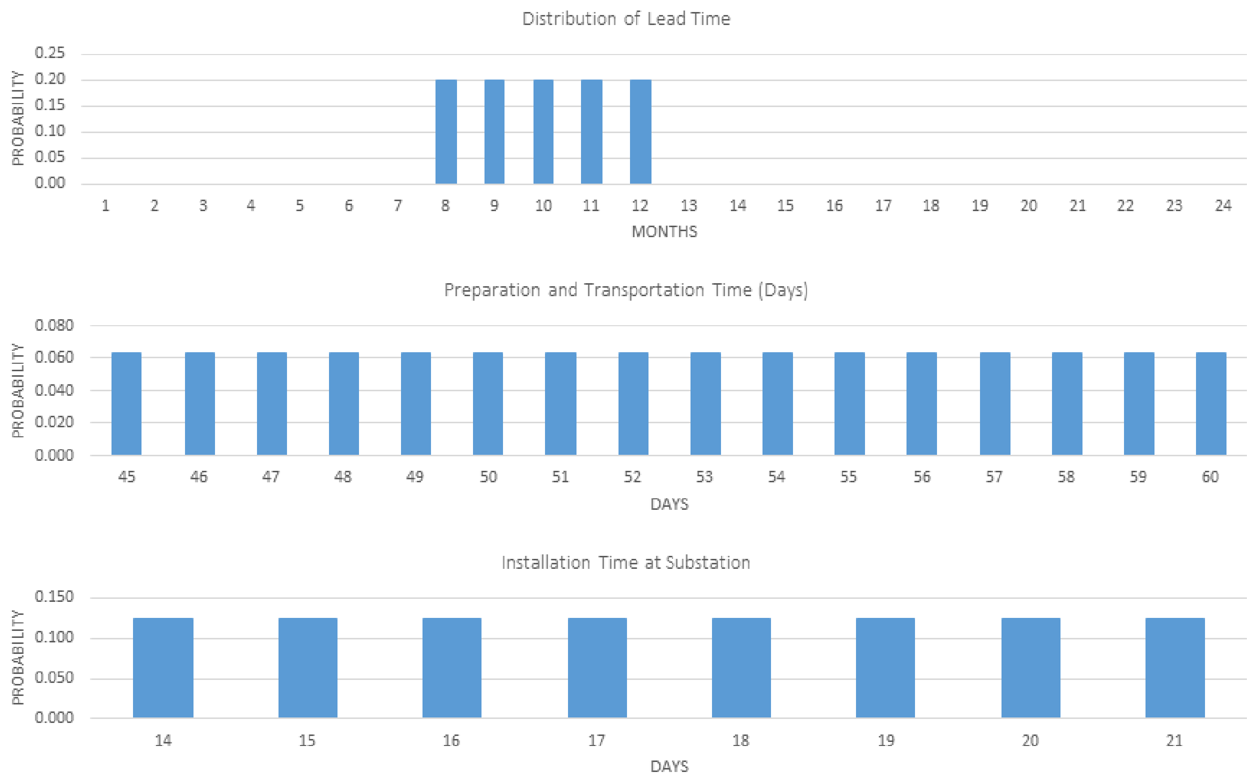


Figure 3-62
100 MVA 115/14-14 kV Inputs – Time Distributions

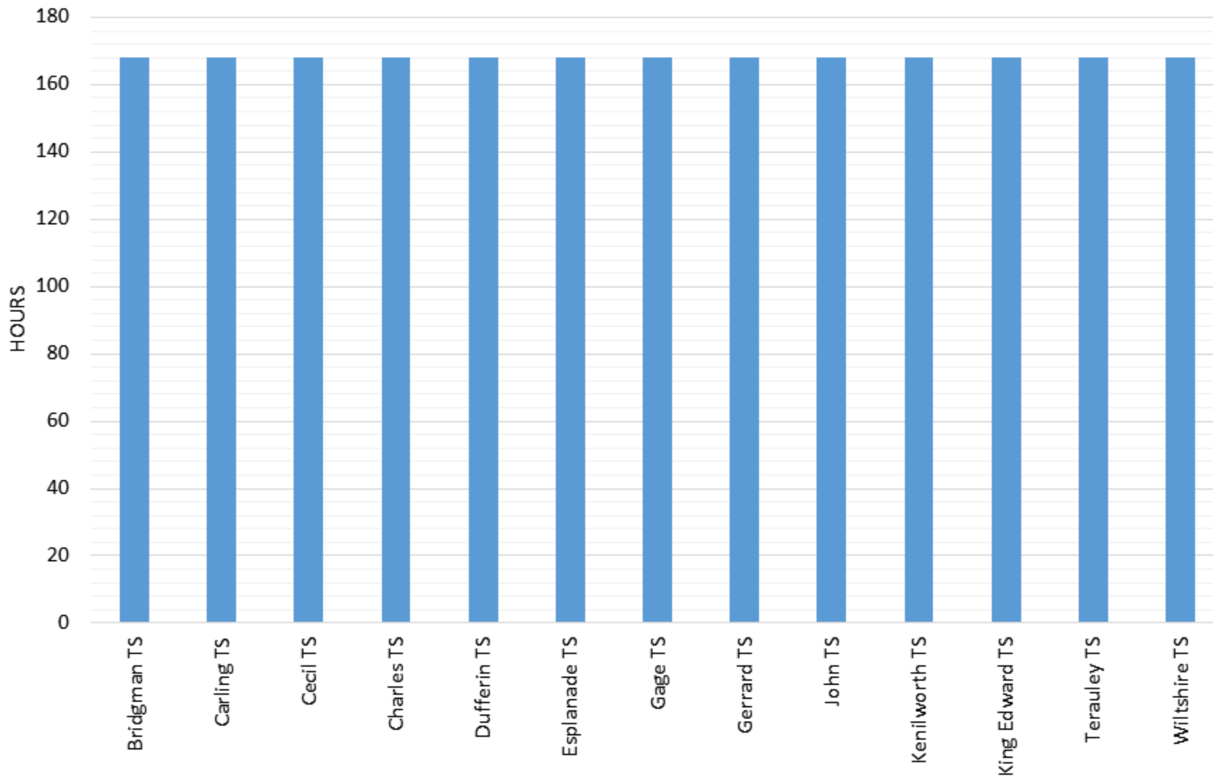


Figure 3-63
100 MVA 115/14-14 kV Inputs – Transportation Time from Spare Depot to Substation

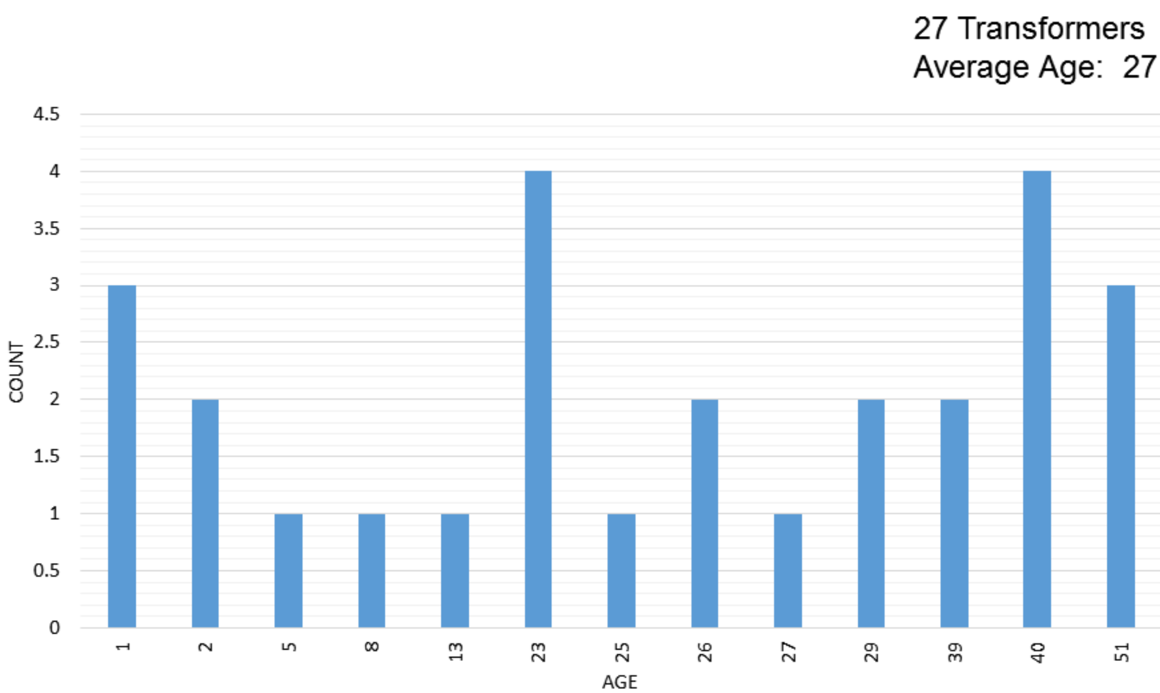


Figure 3-64
100 MVA 230/14-14 kV Inputs – Transformer Age Demographics

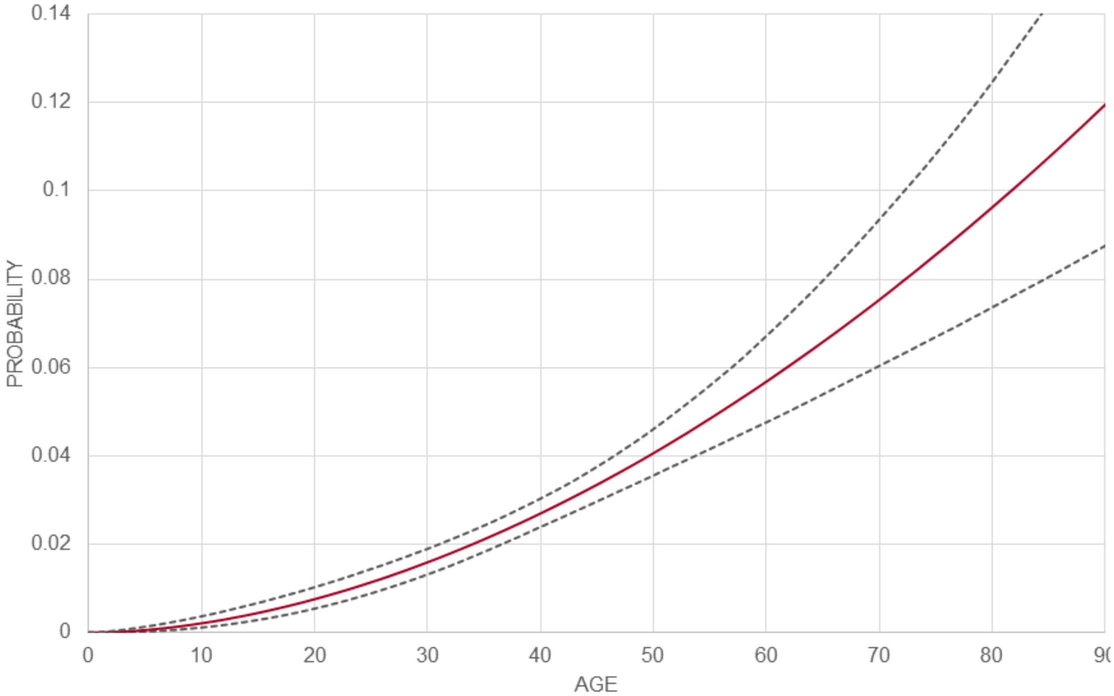
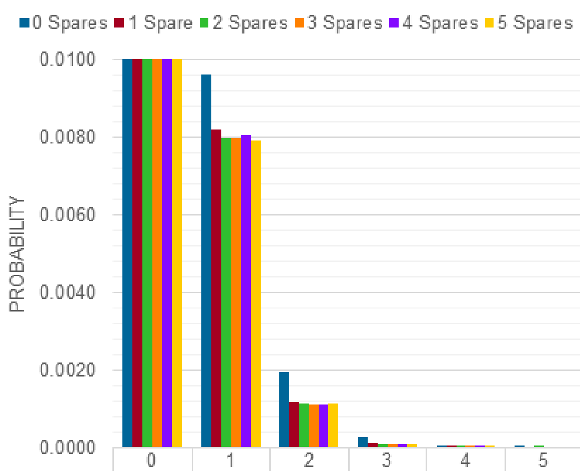


Figure 3-65
100 MVA 230/14-14 kV Inputs – Hazard Function

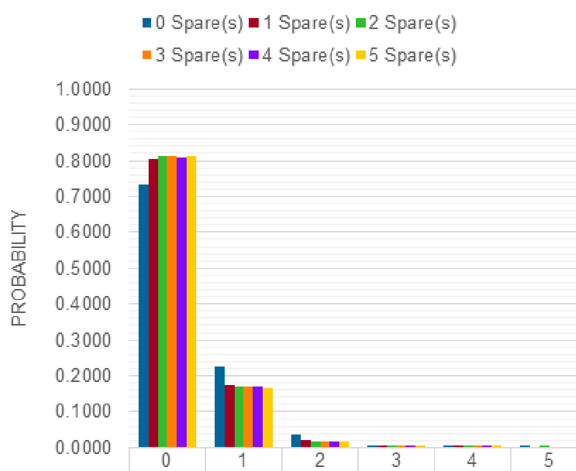
Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that all positions are available for all days?



	0	1	2	3	4	5
0 Spares	0.9881	0.0096	0.0020	0.0003	0.0000	0.0000
1 Spare	0.9905	0.0082	0.0012	0.0001	0.0000	0.0000
2 Spares	0.9908	0.0080	0.0011	0.0001	0.0000	0.0000
3 Spares	0.9908	0.0080	0.0011	0.0001	0.0000	0.0000
4 Spares	0.9907	0.0080	0.0011	0.0001	0.0000	0.0000
5 Spares	0.9909	0.0079	0.0011	0.0001	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that the system is not at full availability at any time?



	0	1	2	3	4	5
0 Spare(s)	0.7331	0.2246	0.0378	0.0041	0.0004	0.0000
1 Spare(s)	0.8030	0.1764	0.0192	0.0013	0.0001	0.0000
2 Spare(s)	0.8103	0.1706	0.0180	0.0011	0.0000	0.0000
3 Spare(s)	0.8109	0.1702	0.0177	0.0011	0.0000	0.0000
4 Spare(s)	0.8094	0.1720	0.0174	0.0011	0.0000	0.0000
5 Spare(s)	0.8124	0.1684	0.0180	0.0011	0.0001	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Figure 3-66
100 MVA 115/14-14 kV Results

750 MVA 500/230 kV

Inputs

- 5 year simulation horizon
- One spare storage location
- Delay to install depends on distance to depot from station
- Pick from closest depot first
- Pick oldest suitable spare first
- Reorder spare upon use
- Minimum threshold time for counting unavailable position: 60 days

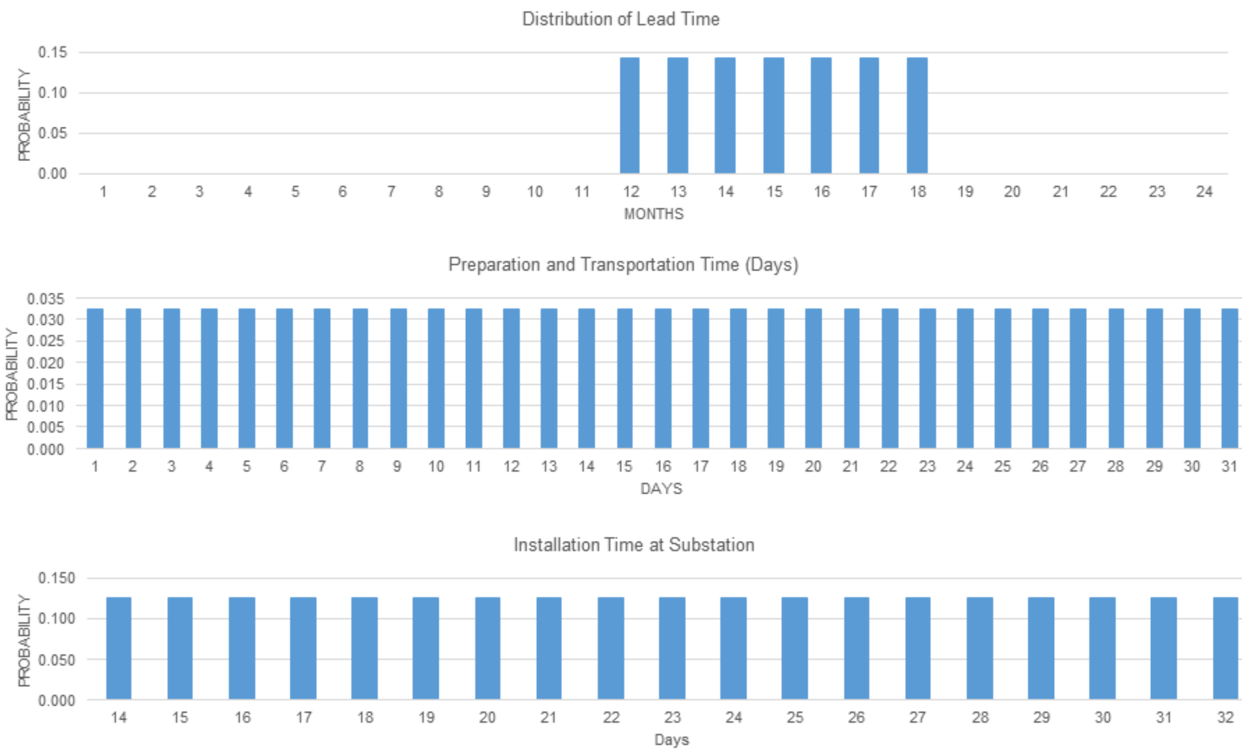


Figure 3-67
750 MVA 500/230 kV Inputs – Time Distributions

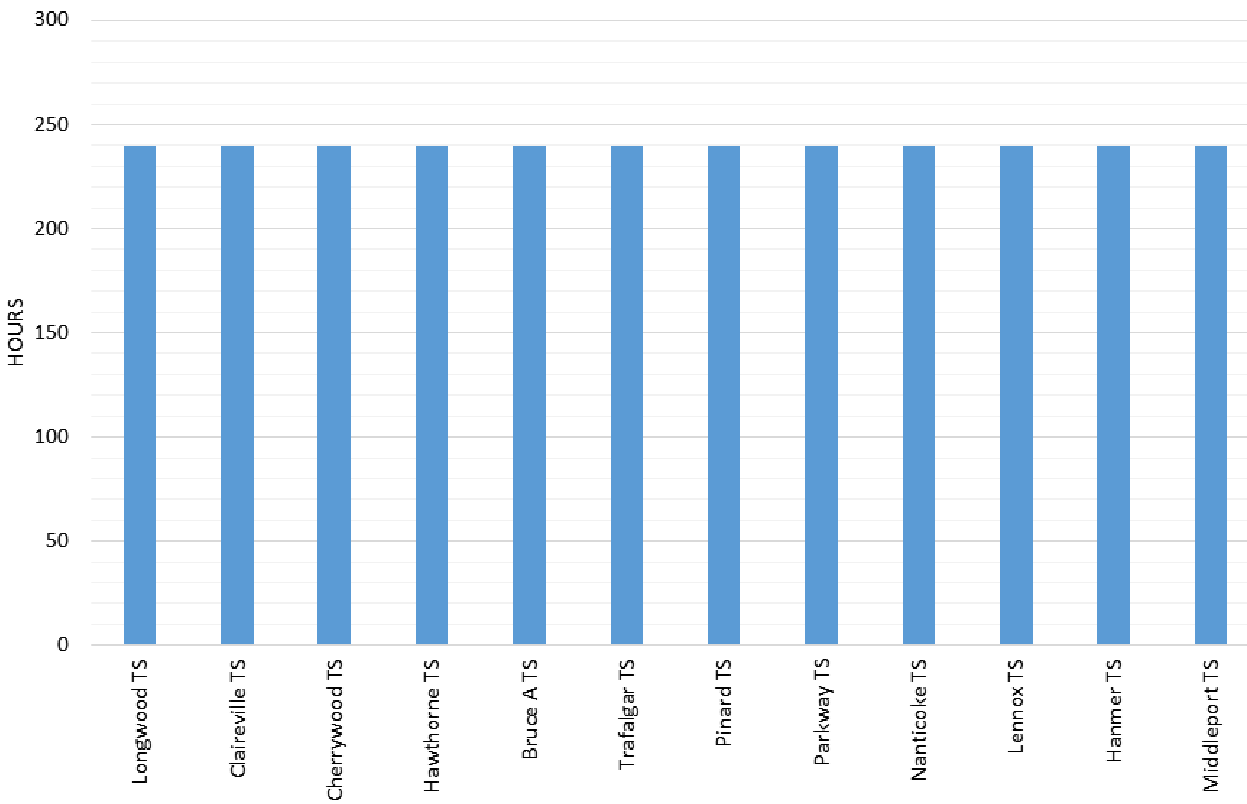


Figure 3-68
750 MVA 500/230 kV Inputs – Transportation Time from Spare Depot to Substation

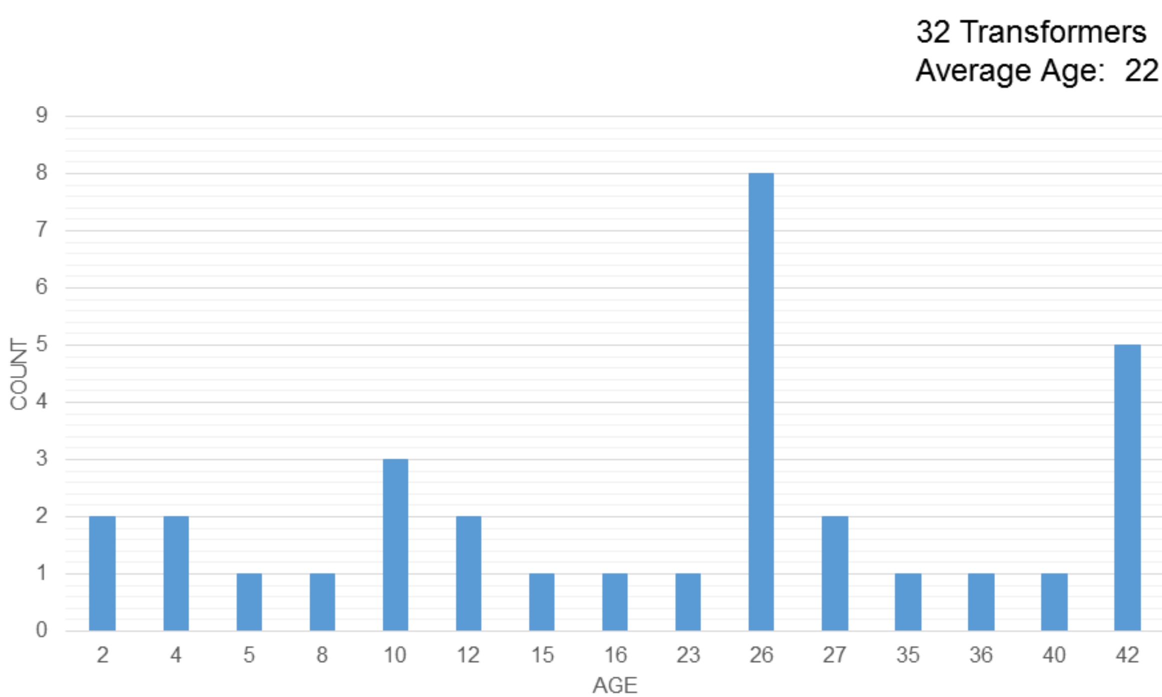


Figure 3-69
750 MVA 500/230 kV Inputs – Transformer Age Demographics

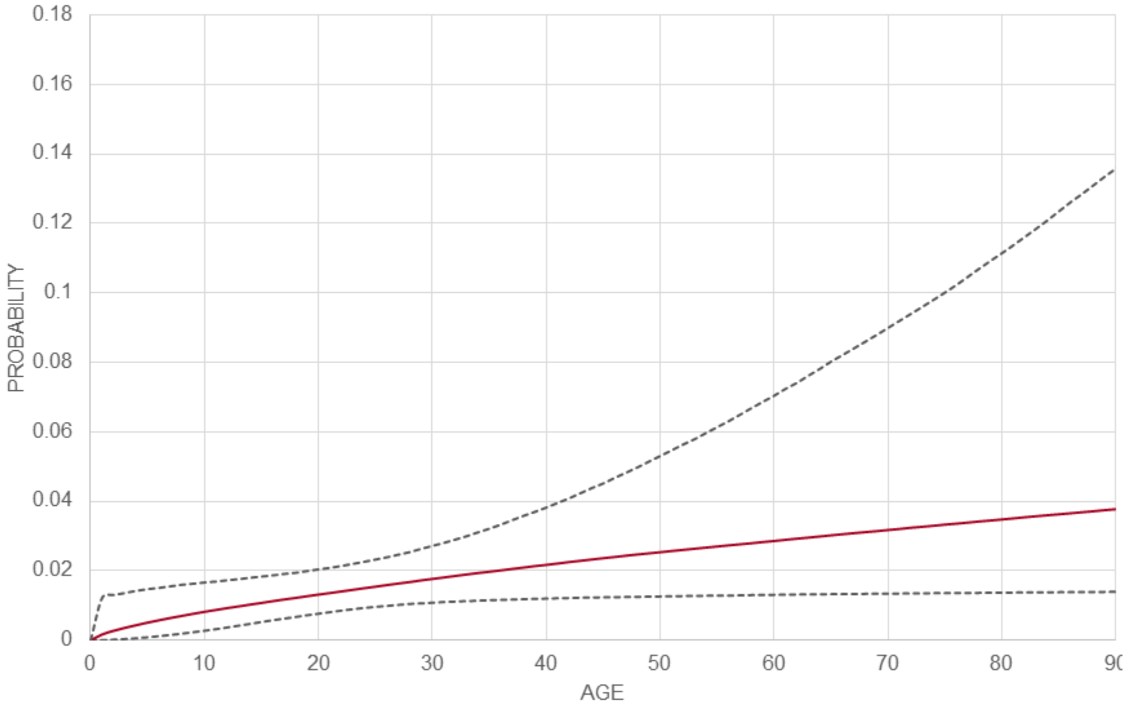
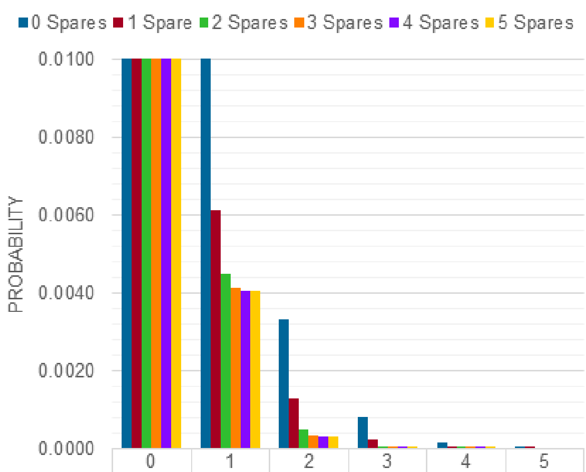


Figure 3-70
750 MVA 500/230 kV Inputs – Hazard Function

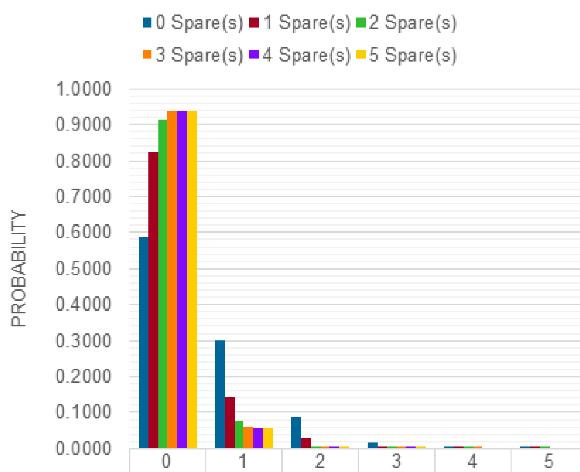
Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that all positions are available for all days?



	0	1	2	3	4	5
0 Spares	0.9856	0.0101	0.0033	0.0008	0.0001	0.0000
1 Spare	0.9923	0.0061	0.0013	0.0002	0.0000	0.0000
2 Spares	0.9949	0.0045	0.0005	0.0000	0.0000	0.0000
3 Spares	0.9955	0.0041	0.0003	0.0000	0.0000	0.0000
4 Spares	0.9956	0.0040	0.0003	0.0000	0.0000	0.0000
5 Spares	0.9956	0.0041	0.0003	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Minimum Threshold time for Counting Unavailable Position: 60 Days
What is the probability that the system is not at full availability at any time?



	0	1	2	3	4	5
0 Spare(s)	0.5885	0.3012	0.0882	0.0187	0.0031	0.0004
1 Spare(s)	0.8232	0.1424	0.0282	0.0054	0.0007	0.0001
2 Spare(s)	0.9154	0.0769	0.0068	0.0007	0.0001	0.0000
3 Spare(s)	0.9359	0.0613	0.0026	0.0001	0.0000	0.0000
4 Spare(s)	0.9396	0.0583	0.0020	0.0001	0.0000	0.0000
5 Spare(s)	0.9396	0.0584	0.0020	0.0000	0.0000	0.0000

NUMBER OF POSITIONS UNAVAILABLE

Figure 3-71
750 MVA 500/230 kV Results

4

SUMMARY AND DISCUSSION OF RESULTS

The analytical results presented in the preceding chapter have been reviewed by Hydro One subject matter experts and utilized to evaluate their current spares stocking levels. One view comparing the results from the two calculations is presented in Table 4-1 below.

Study Group	System Availability (in %) (What is the probability that the system is not at full availability at any time?)					Hydro One Optimized Number of Spares (Hydro One Spares Model)	Hydro One Optimized Number of Spares (EPRI Spares Model)
	0 Spares	1 Spare	2 Spares	3 Spares	4 Spares		
125 MVA 230/44 kV	52.24	77.44	90.88	94.37	95.23	2	2
125 MVA 230/28-28 kV	51.03	78.46	89.09	91.67	92.11	2	2
83 MVA 230/28 kV	70.26	91.05	96.50	97.32	97.30	2	2
83 MVA 230/44 kV	73.48	92.65	97.25	97.81	97.83	2	3
100 MVA 230/14-14 kV	94.32	99.56	99.67	99.66	99.65	1	1
250 MVA 230/115 kV	68.41	89.84	96.03	97.18	97.27	2	2
125 MVA 230/115 kV	82.49	96.34	98.43	98.60	98.61	2	2
75 MVA 115/14-14 kV	37.32	61.09	81.31	89.48	92.17	2	
42MVA 115/14 kV	96.79	99.77	99.85	99.85	99.85	2	2
42MVA 115/28 kV	69.21	89.52	93.69	94.36	94.28	2	2
83MVA 115/28 kV	69.22	91.39	97.35	98.22	98.30	2	2
42 MVA 115/44 kV	73.28	93.24	98.01	98.5	98.54	2	2
100 MVA 115/14-14 kV	73.31	80.30	81.03	81.09	80.94	2	2
750 MVA 500/230 kV	58.85	82.32	91.54	93.59	93.96	2	2

Table 4-1
Summary of Select Results

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ELECTRIC POWER RESEARCH INSTITUTE

Expected Service Life (ESL) Survey of Transformers and Circuit Breakers

Transformers and Circuit Breakers Expected Service Life Survey

Technical Update, February 2018

EPRI Project Manager
B. Desai

THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

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Electric Power Research Institute (EPRI)
1300 West W.T. Harris Blvd.
Charlotte, NC28262

Principal Investigator
B. Desai

Principal Investigator
W. Barfield

Coplanar Consulting LLC
Yardley, PA19067

Principal Investigator
M. Lebow

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EXECUTIVE SUMMARY

Utilities have been maintaining substation equipment reliably since the industry's inception but now many are facing increased challenges to reduce operating and maintenance costs without adversely affecting service levels or investment requirements. In this setting, utilities may benefit from knowing what programs and techniques their peers have implemented. To that end, EPRI has conducted a series of industry surveys assessing key substation equipment maintenance and replacement practices. As utilities consider modifying their maintenance or replacement programs, they can benefit from the knowledge and experience of others. Identification of best practices, as well as lessons learned from less successful trials, facilitates peer collaboration and improvements for all.

This report presents the results of two surveys designed to acquire information and insights on industry attitudes and practices related to asset management of transmission circuit breakers and transformers. Survey results may help utilities to learn how peer companies are responding to similar challenges, and may also help inform and guide research and development efforts to further improve substation asset management practices.

The information provided may be used to assess the state of the industry on these topics, determine best practices and establish areas of additional research and development need.

Keywords

Substations
Asset management
High voltage circuit breakers
Power transformers

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1
INTRODUCTION

This report presents the results of two surveys designed to acquire information and insights on industry attitudes and practices related to asset management of transmission circuit breakers and transformers. Survey results may help utilities to learn how peer companies are responding to similar challenges, and may also help inform and guide research and development efforts to further improve substation asset management practices.

Survey respondents are utility personnel who are members of the EPRI Substation Task Force.

Background

Utilities have been maintaining substation equipment reliably since the industry's inception but now many are facing increased challenges to reduce operating and maintenance costs without adversely affecting service levels or capital requirements. To address these challenges, many utilities are modifying existing maintenance and replacement practices and moving toward augmenting or replacing traditional methods with new approaches, such as condition and risked-based maintenance and replacement scheduling.

Utility maintenance managers and engineers need access to information about proven processes, organizational strategies, related technologies, and successful applications to help achieve high performance levels. Collaboration to share best practices and provide a basis for self-benchmarking is valuable for improving substation asset management and maintenance processes. To assist utilities in collecting the required information, EPRI has conducted a series of surveys of the current practices and experiences concerning substation equipment. This report presents the results of two surveys on high voltage circuit breaker and power transformer assessment and replacement practices.

Objectives

The main objective of the surveys was to gather and share information about how utilities are deciding which circuit breakers and transformers to replace and when.

Approach

A web-based survey tool was used to construct a set of focused questions that could provide an assessment of current industry assessment and replacement practices for transmission circuit breakers and power transformers. The survey questions are presented in Appendix A and B. Not all respondents answered all questions.

Surveys previously were conducted in 2009, 2010 and 2016[1, 2, 3]. This report presents updated responses and more detailed focus on utility practices regarding circuit breaker and transmission assessment and replacement.

Report Organization

The report is organized into the following chapters.

Chapter 1: Introduction

Chapter 2: Survey Respondent Characteristics: Circuit Breakers

Chapter 3: End of Life Concerns for Circuit Breakers

Chapter 4: Assessment and Replacement Practices for Circuit Breakers

Chapter 5: Survey Respondent Characteristics: Transformers

Chapter 6: End of Life Concerns for Transformers

Chapter 7: Assessment and Replacement Practices for Transformers

Chapter 8: Summary and Next Steps

Appendix A: Survey Questions: Circuit Breakers

Appendix B: Survey Questions: Transformers

References

1. *Asset Management Best Practices: Assessment of the Implementation for Substation Transformers, Circuit Breakers and Disconnect Switches.* EPRI, Palo Alto, CA: 2010. 1020005
2. *Assessment of High Voltage Disconnect Switch Maintenance Practices.* EPRI, Palo Alto, CA: 2010. 1020013
3. *Substation Equipment Asset Management and Maintenance Practices: Utility Experience Sharing.* EPRI, Palo Alto, CA: 2016. 3002007830.

2
SURVEY RESPONDENT CHARACTERISTICS: CIRCUIT BREAKERS

To help place the survey results in context and better interpret the responses, the characteristics of the utility participants and their respective circuit breaker fleets are presented in this chapter.

Survey respondents are members of the EPRI Substation Task Force.

Circuit Breaker Survey

Job Classification

Each circuit breaker survey respondent was classified by job description as shown in Figure 2-1.

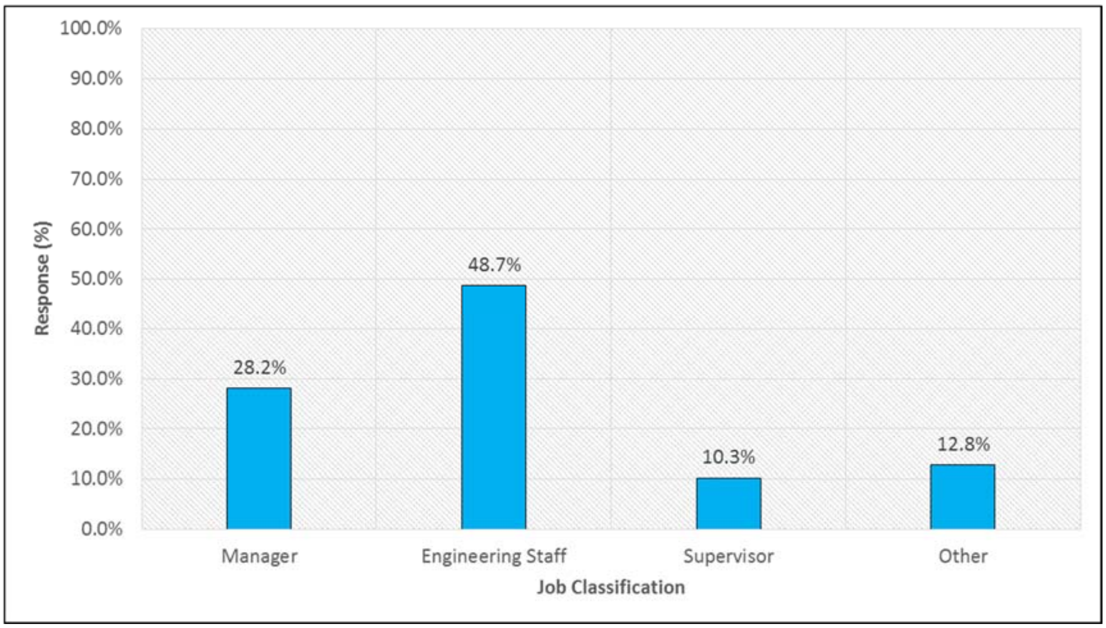

Figure 2-1
Job Classification

Organization Classification

Each respondent was classified by organization function, as presented in Figure 2-2.

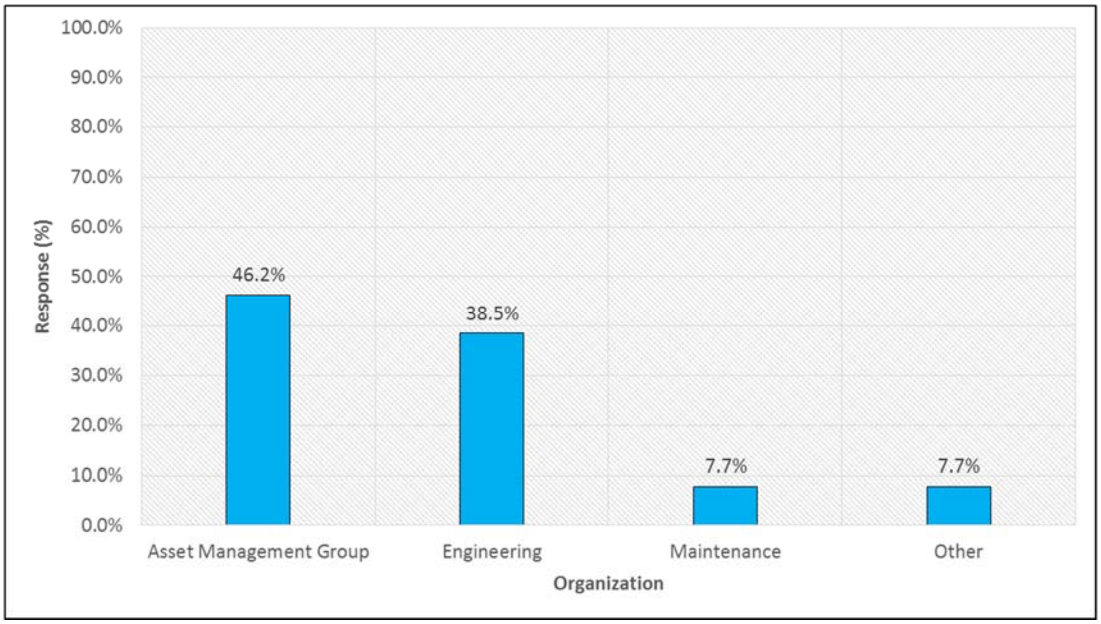

Figure 2-2
Organization Classification

Company Description

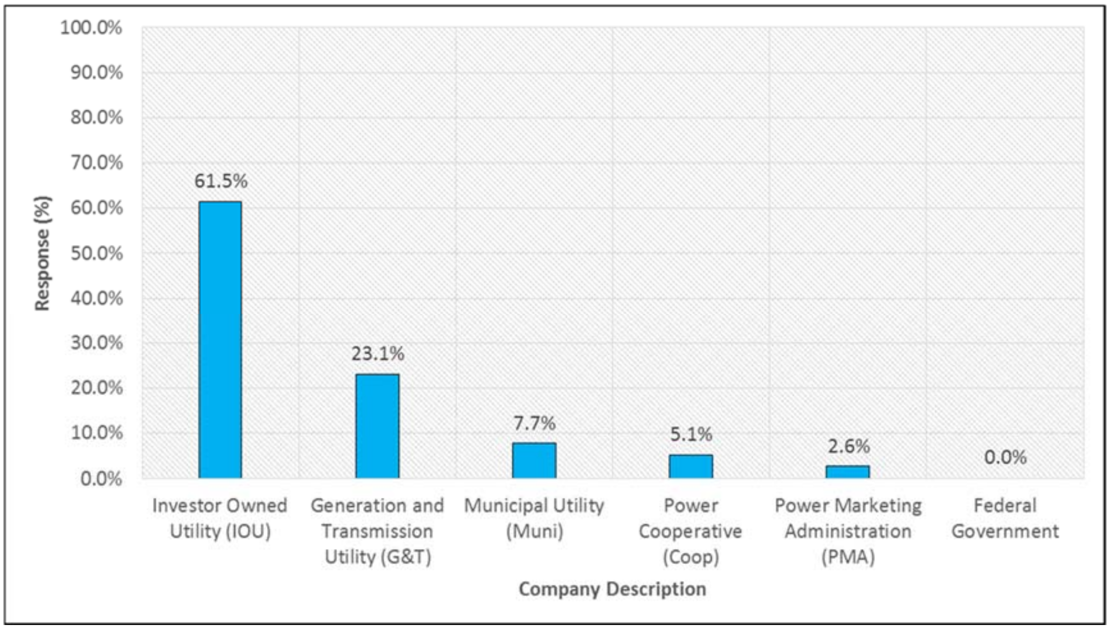

Figure 2-3
Company Description

Regulatory Structure

Respondents were asked about their company and its regulatory structure. Responses are shown in Figures 2-3 and 2-4.

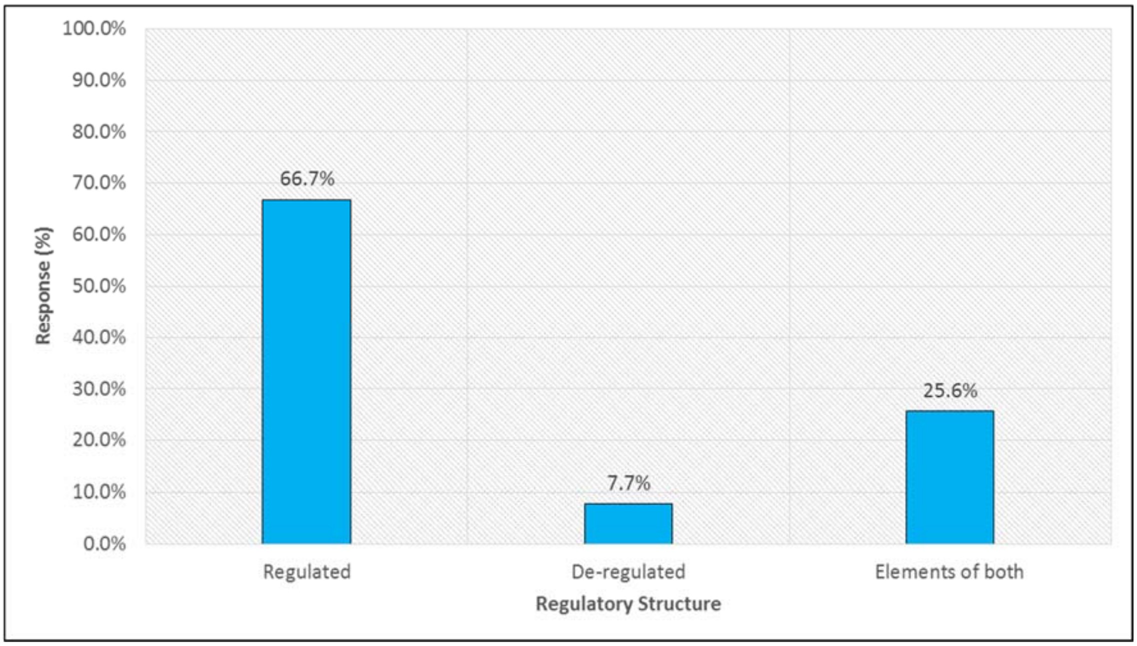

Figure 2-4
Regulatory Structure

Asked what assets their companies owned, respondents provided the information presented in Table 2-1. "None" means the respondent had none of that category. Whereas, "Part of Core Business" means the respondent considered that category to be a core business activity. Consider "Distribution" as an example. 10.3% of the respondents had no distribution assets. 71.8% considered distribution to be a core business. The balance had some distribution but did not consider it to be a core activity.

	None	Part of Core Business
Generation	20.5%	76.9%
Transmission	2.6%	94.9%
Distribution	10.3%	71.8%

Table 2-1
Assets Owned

System and Fleet Characteristics

Peak Load

Respondents were asked to define their system's peak load. Results are shown in Figure 2-5.

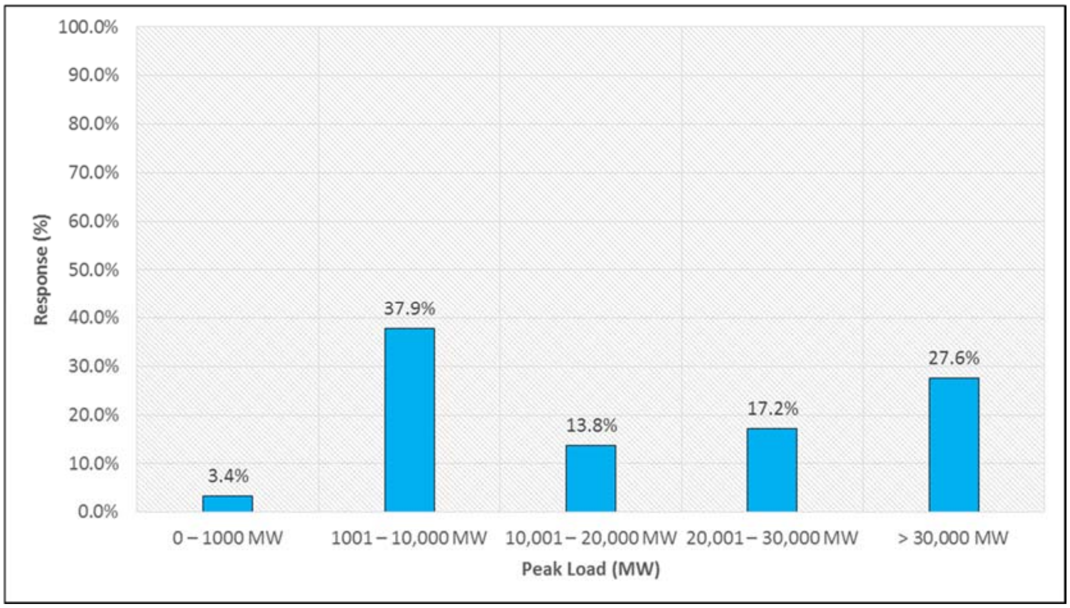

Figure 2-5
System Peak Load

Number of Live Tank SF_6 Circuit Breakers

Survey Question: *"How many transmission circuit breakers (>= 34 kV) do you have in service that are Live Tank SF_6 Circuit Breakers?"*

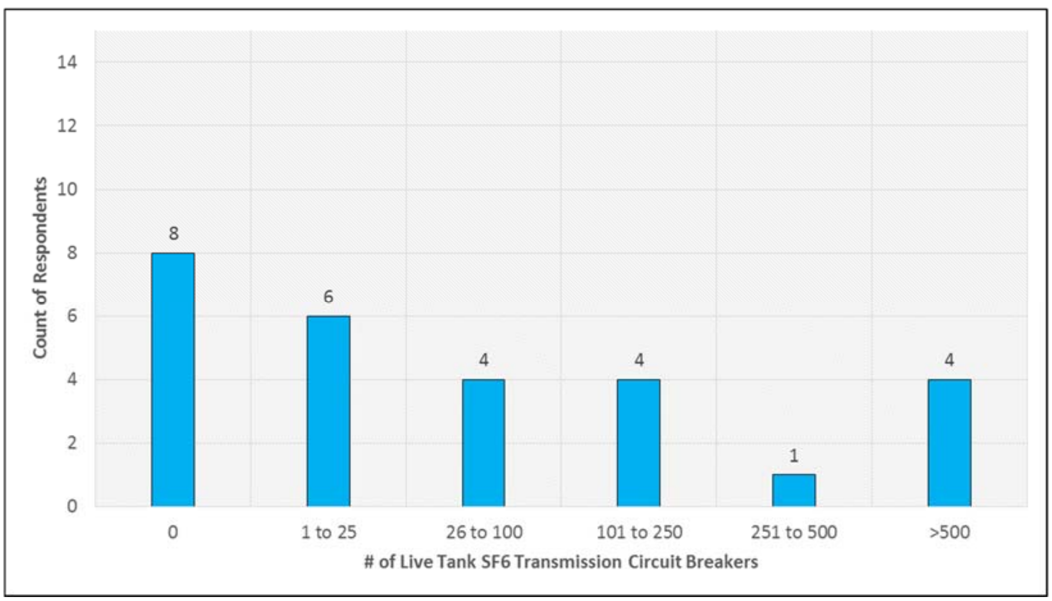

Figure 2-6
Number of Live Tank SF_6 Circuit Breakers

Number of Dead Tank SF_6 Circuit Breakers

Survey Question: *"How many transmission circuit breakers (>= 34 kV) do you have in service that are Dead Tank SF_6 Circuit Breakers?"*

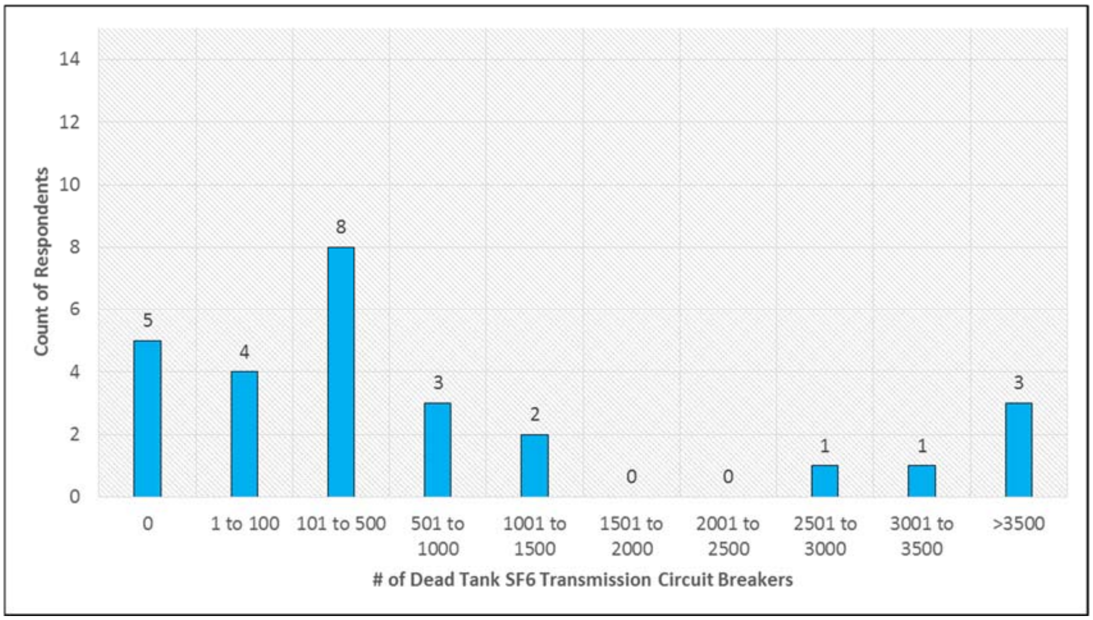

Figure 2-7
Number of Dead Tank SF_6 Circuit Breakers

Number of Bulk Oil Circuit Breakers

"How many transmission circuit breakers (>= 34 kV) do you have in service that are Bulk Oil Circuit Breakers?"

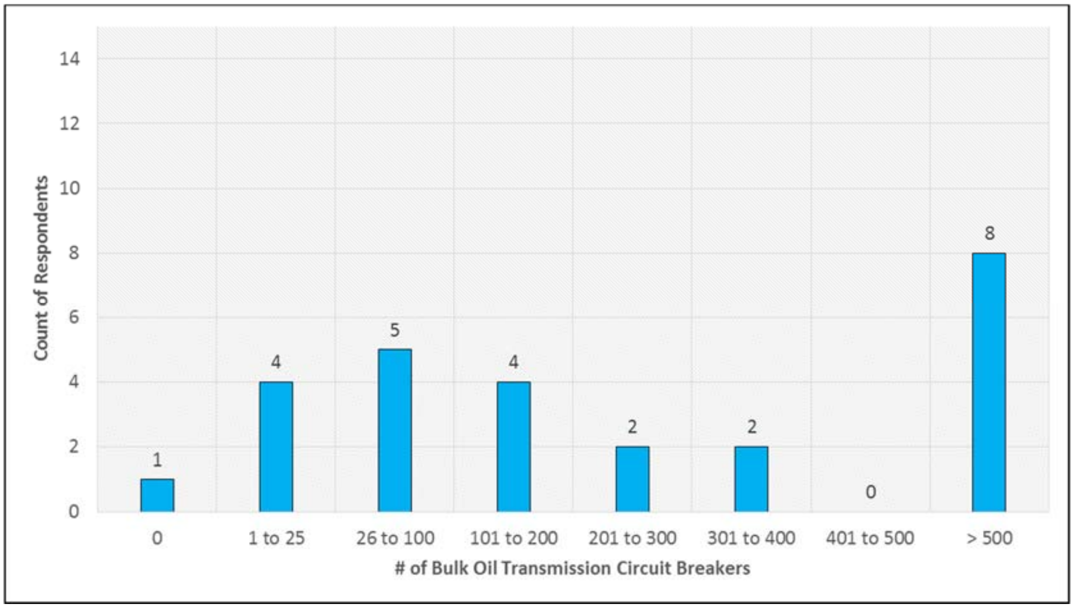

Figure 2-8
Number of Bulk Oil Circuit Breakers

Number of Minimum Oil Circuit Breakers

"How many transmission circuit breakers (>= 34 kV) do you have in service that are Minimum Oil Circuit Breakers?"

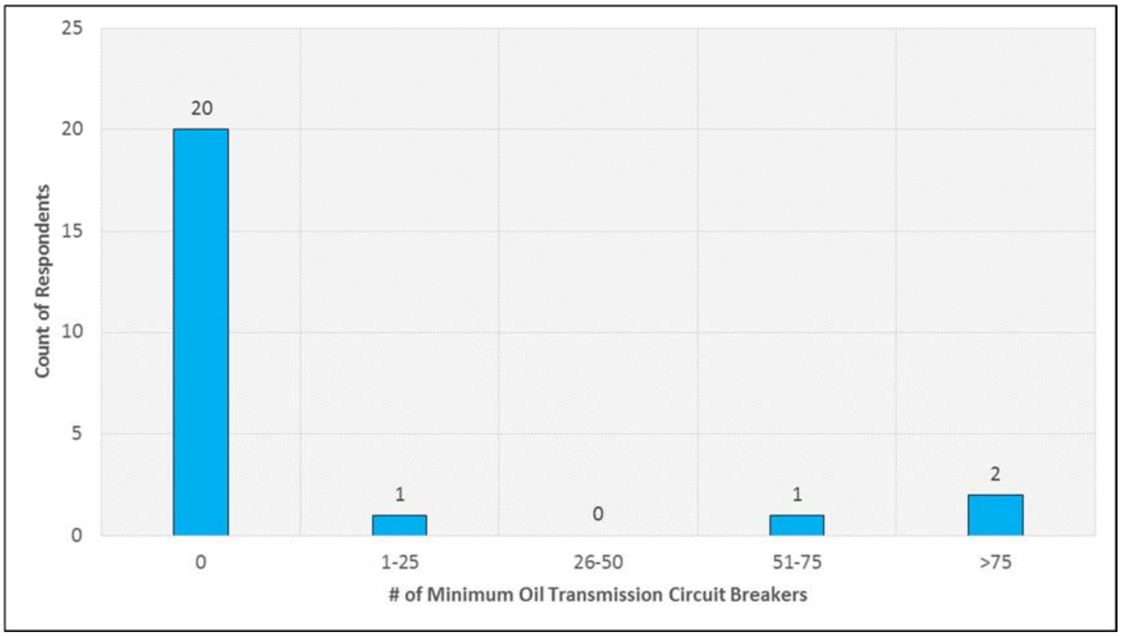

Figure 2-9
Number of Minimum Oil Circuit Breakers

Age Breakdown of Circuit Breaker Fleet

"What is the age breakdown of your circuit breaker fleet?"

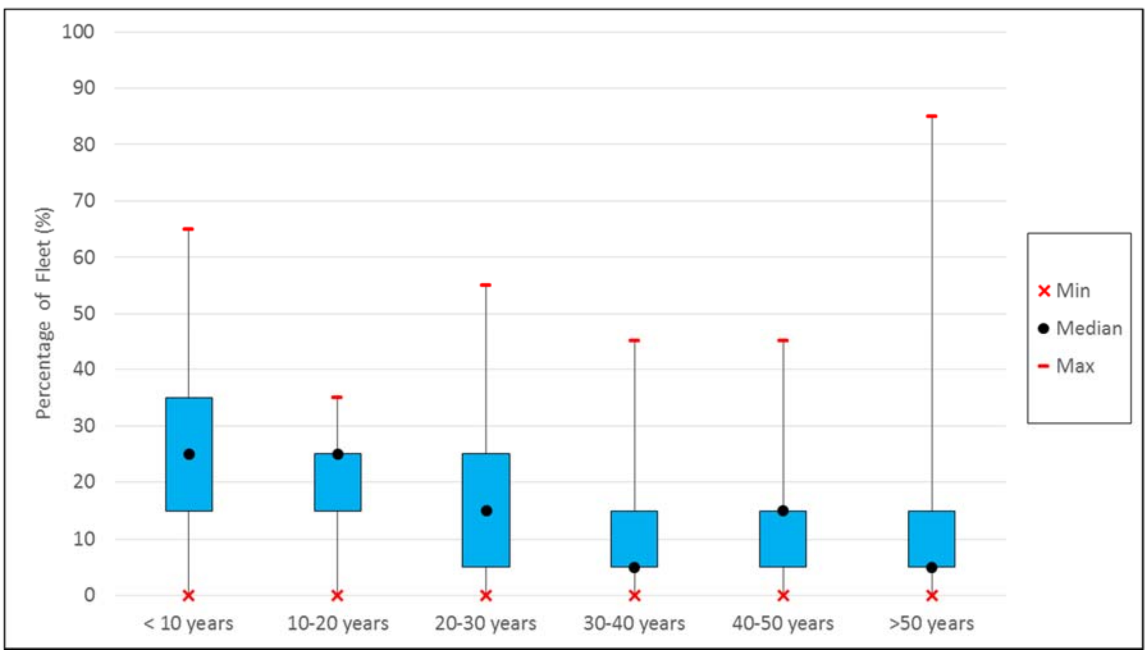

Figure 2-10
Age Breakdown of Circuit Breaker Fleet

3
END OF LIFE CONCERNS FOR CIRCUIT BREAKERS

End of Life (EOL) Definitions

Utilities use different terms to define the end of life and expected service life of assets. For example, Hydro One uses the following definitions:

End of Life (EOL): The high likelihood of failure, or loss of an asset's ability to provide the intended functionality as determined through diagnostic data, wherein the failure or loss of functionality would cause unacceptable consequences. EOL can be further divided into three sub-categories:

- **Technical EOL**: The asset has failed, or condition assessment data indicates it is likely to do so, or it can no longer be expected to perform its function reliably
- **Economic EOL**: Unacceptable levels of maintenance costs are required to achieve the required performance/function.
- **Strategic EOL**: Necessary spares parts or skills set are unavailable; or the forecast loading or short circuit levels have exceeded the rating of the asset.

Expected Service life (ESL): The average time in years that an asset can be expected to operate under normal system conditions.

Use of Definitions and Utility Comments

Respondents were asked whether their company used these or similar EOL definitions. Responses are shown in Figure 3-1.

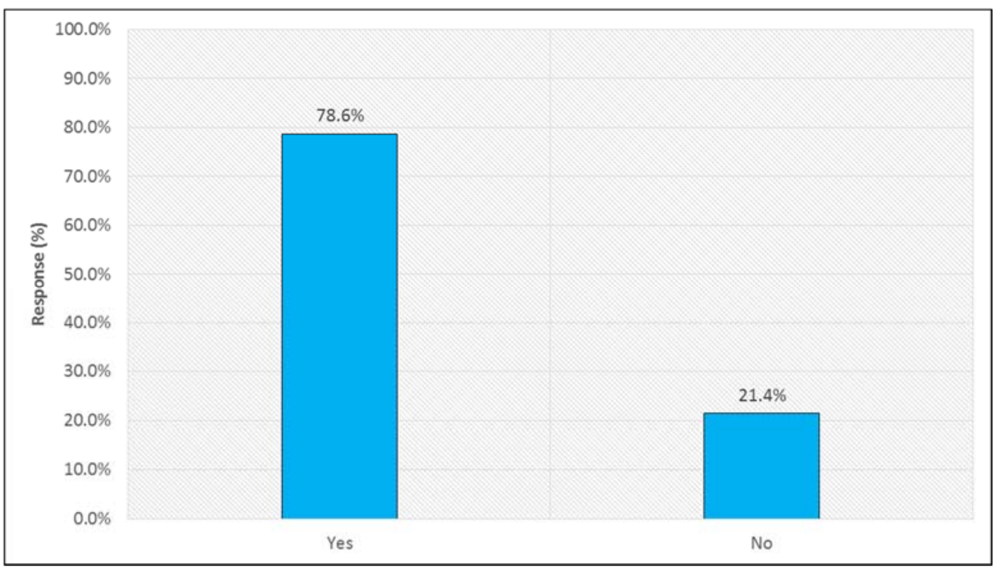

Figure 3-1
Use of Hydro One or Similar Definitions for End of Life and Expected Service Life

Respondents who answered no to this question were invited to provide comment. These are presented below.

> "There are definitions used for ESL but they lack strict guidelines aside from financial applications."
>
> "Do not use those terms specifically, but follow the same basic definitions."
>
> [Utility] does not use the exact definition, but applies the concept. In general: End of Life: The asset has failed, or condition assessment data indicates it is likely to do so, or it can no longer be expected to perform its function reliably. Parts obsolescence / High Maintenance: Necessary spares parts or skills set are unavailable; or the forecast loading or short circuit levels have exceeded the rating of the asset. Unacceptable levels of maintenance costs are required to achieve the required performance/function.
>
> "No clear definition but the philosophy is similar."
>
> "Do not distinguish different types of EOL for planning purposes."
>
> "Technical EOL only"

Ages of Concern about Leaving Breakers in Service

Oil Circuit Breakers

Respondents were asked the following question: *"For the following oil circuit breaker voltage levels, at what age would you start getting concerned about leaving the asset in service (ideally target for planned replacement in the next 5 to 10 years)?"*

Responses by voltage level are shown in Figure 3-2, Figure 3-3, Figure 3-4 and Table 3-1.

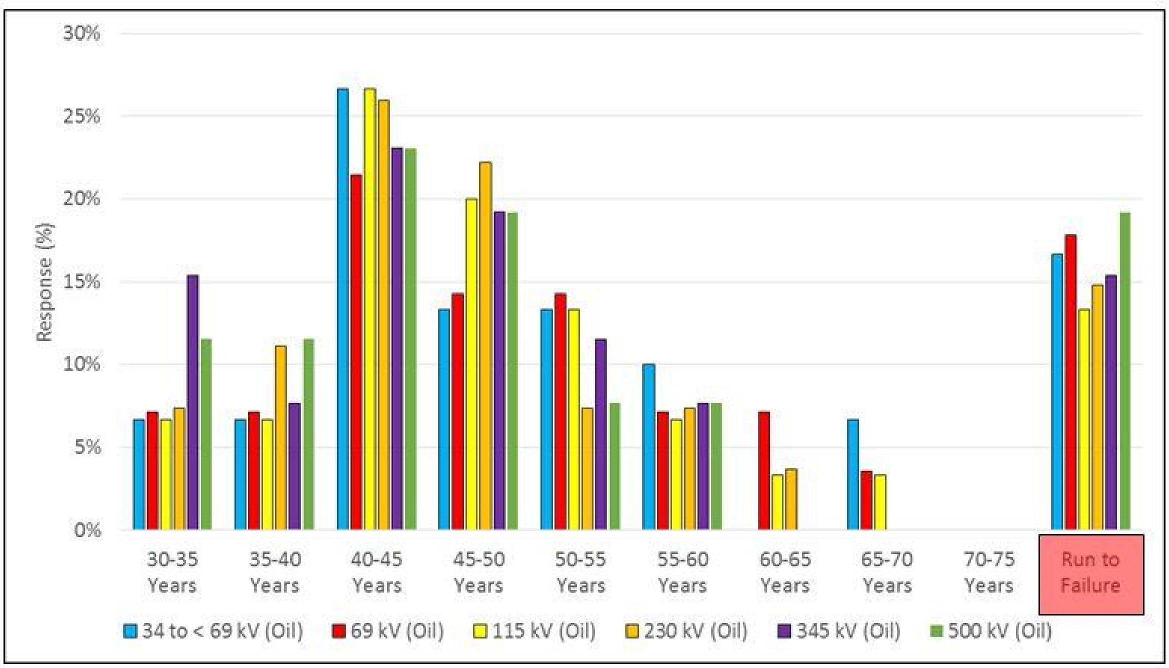

Figure 3-2
Age of Concern about Leaving in Service: Oil Breakers

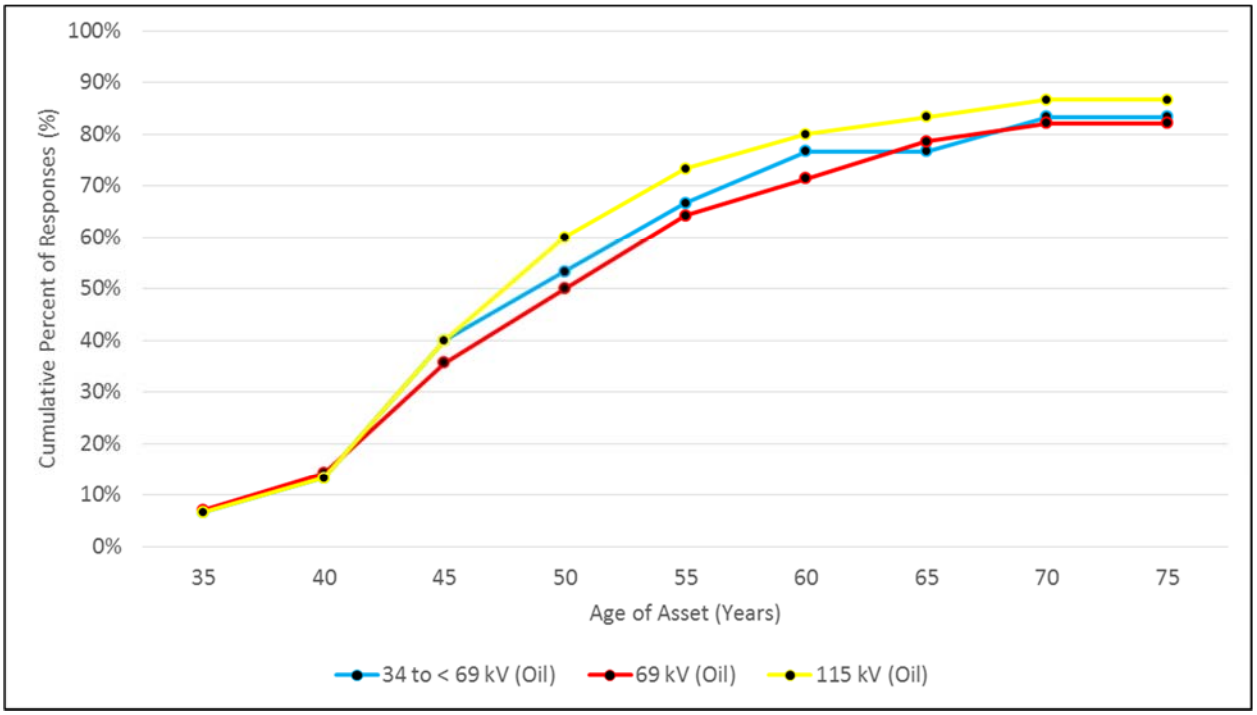

Figure 3-3
Age of Concern: Cumulative Percentage – 34kV to 115kV Oil Circuit Breakers

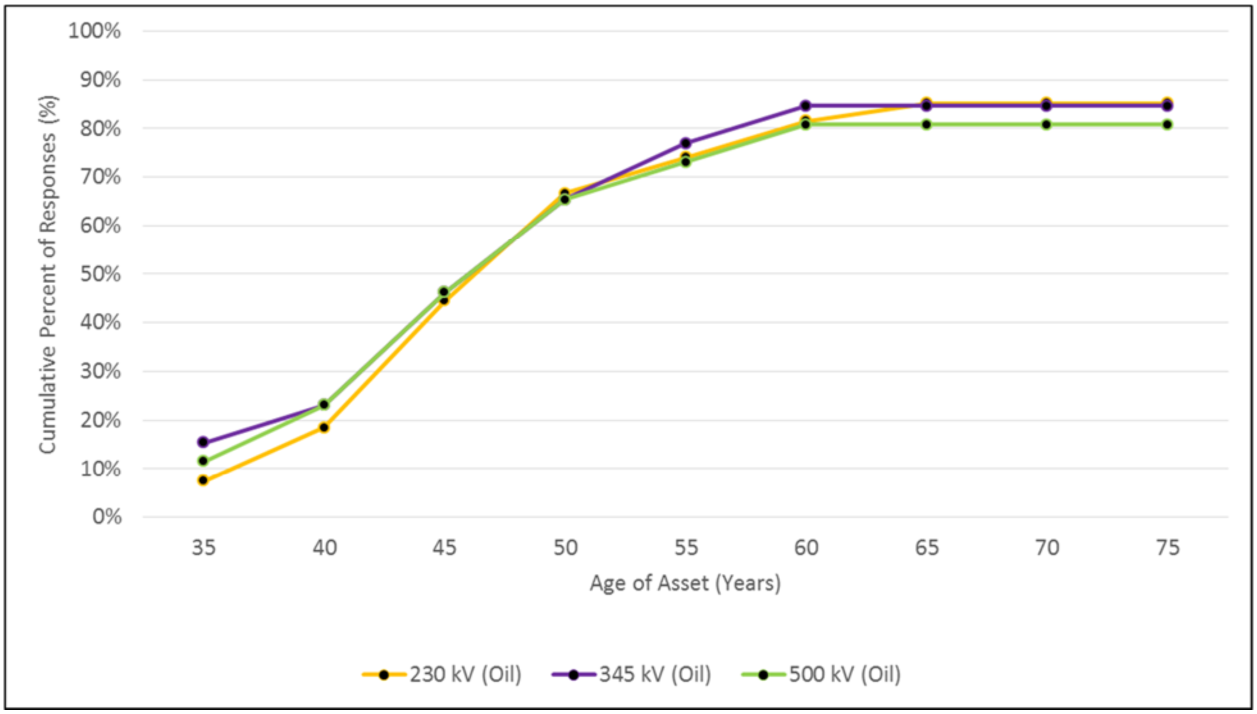

Figure 3-4
Age of Concern: Cumulative Percentage – 230kV to 500kV Oil Circuit Breakers

Table 3-1
Age of Concern about Leaving in Service: Oil Breakers

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Run to Failure
34 to < 69 kV (Oil)	7%	7%	27%	13%	13%	10%	0%	7%	0%	17%
69 kV (Oil)	7%	7%	21%	14%	14%	7%	7%	4%	0%	18%
115 kV (Oil)	7%	7%	27%	20%	13%	7%	3%	3%	0%	13%
230 kV (Oil)	7%	11%	26%	22%	7%	7%	4%	0%	0%	15%
345 kV (Oil)	15%	8%	23%	19%	12%	8%	0%	0%	0%	15%
500 kV (Oil)	12%	12%	23%	19%	8%	8%	0%	0%	0%	19%

Gas Circuit Breakers

Figure 3-5, Figure 3-6, Figure 3-7 and Table 3-2 show responses to the question, *"For the following gas circuit breaker voltage levels, at what age would you start getting concerned about leaving the asset in service (ideally target for planned replacement in the next 5 to 10 years)?"*

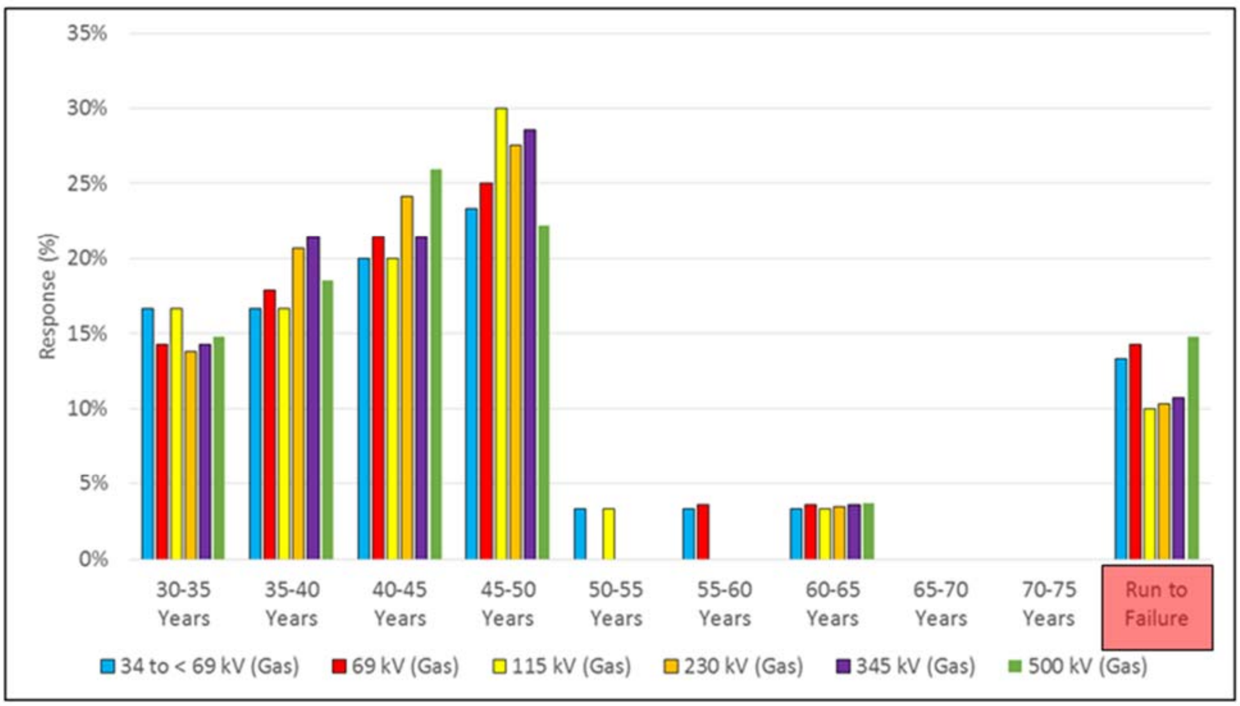

Figure 3-5
Age of Concern about Leaving in Service: Gas Breakers

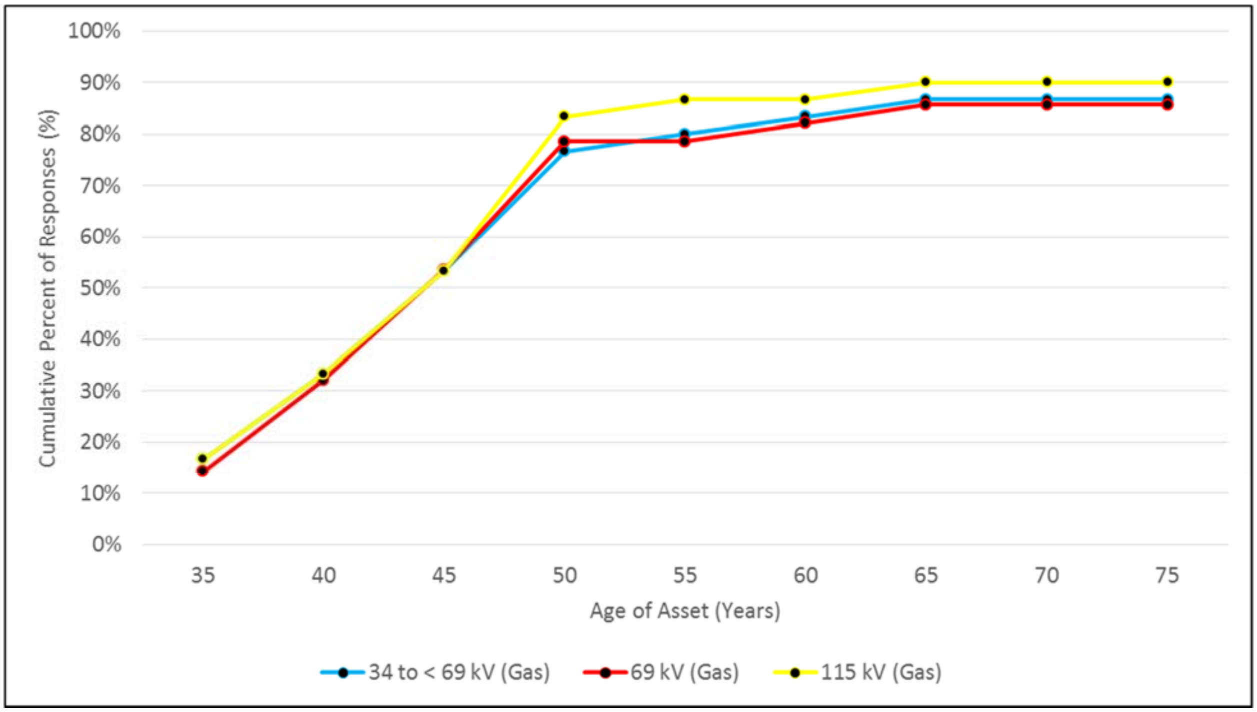

Figure 3-6
Age of Concern: Cumulative Percentage – 34kV to 115kV Gas Circuit Breakers

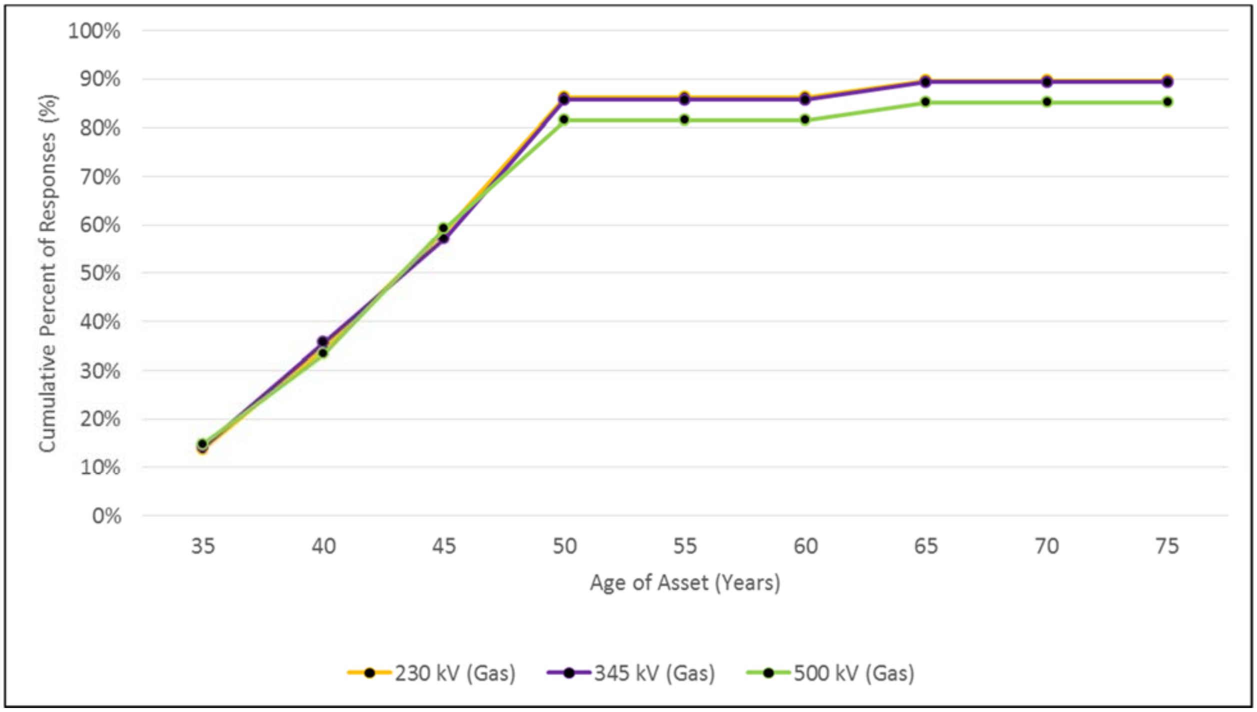

Figure 3-7
Age of Concern: Cumulative Percentage – 230kV to 500kV Gas Circuit Breakers

Table 3-2
Age of Concern about Leaving in Service: Gas Breakers

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Run to Failure
34 to < 69 kV (Gas)	17%	17%	20%	23%	3%	3%	3%	0%	0%	13%
69 kV (Gas)	14%	18%	21%	25%	0%	4%	4%	0%	0%	14%
115 kV (Gas)	17%	17%	20%	30%	3%	0%	3%	0%	0%	10%
230 kV (Gas)	14%	21%	24%	28%	0%	0%	3%	0%	0%	10%
345 kV (Gas)	14%	21%	21%	29%	0%	0%	4%	0%	0%	11%
500 kV (Gas)	15%	19%	26%	22%	0%	0%	4%	0%	0%	15%

Vacuum Circuit Breakers

Figure 3-8, Figure 3-9 and Table 3-3 show participant responses to the same question for vacuum breakers, *"For the following vacuum circuit breaker voltage levels, at what age would you start getting concerned about leaving the asset in service (ideally target for planned replacement in the next 5 to 10 years)?"*

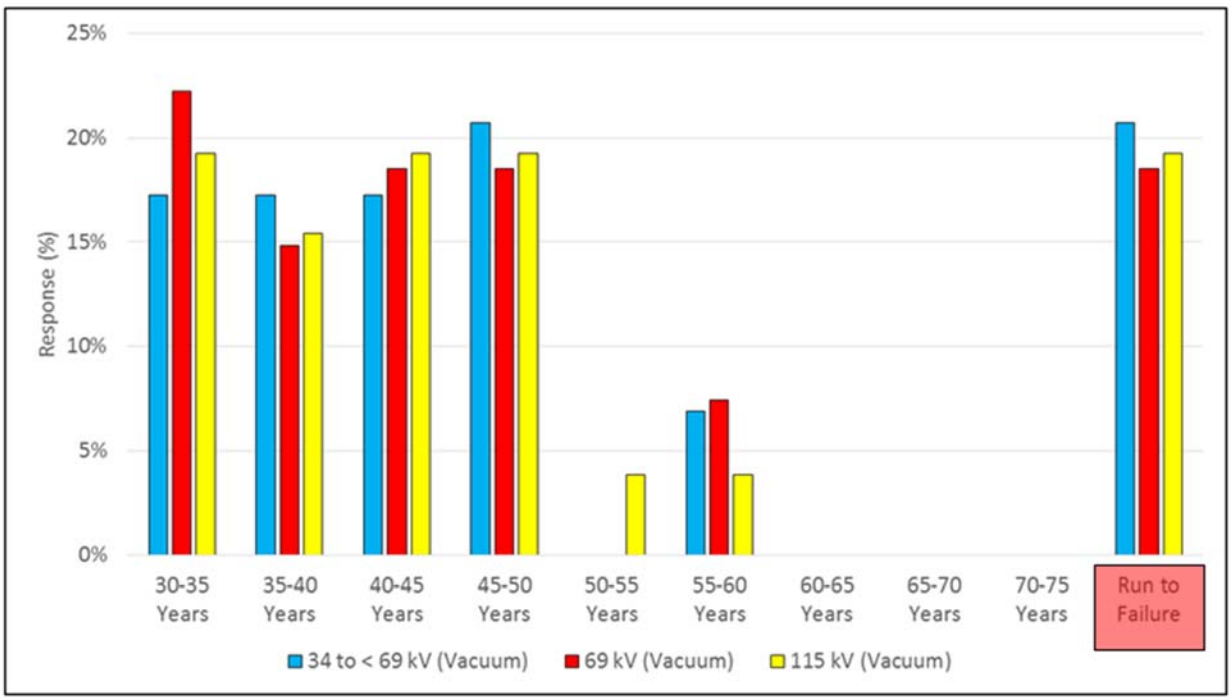

Figure 3-8
Age of Concern about Leaving in Service: Vacuum Circuit Breakers

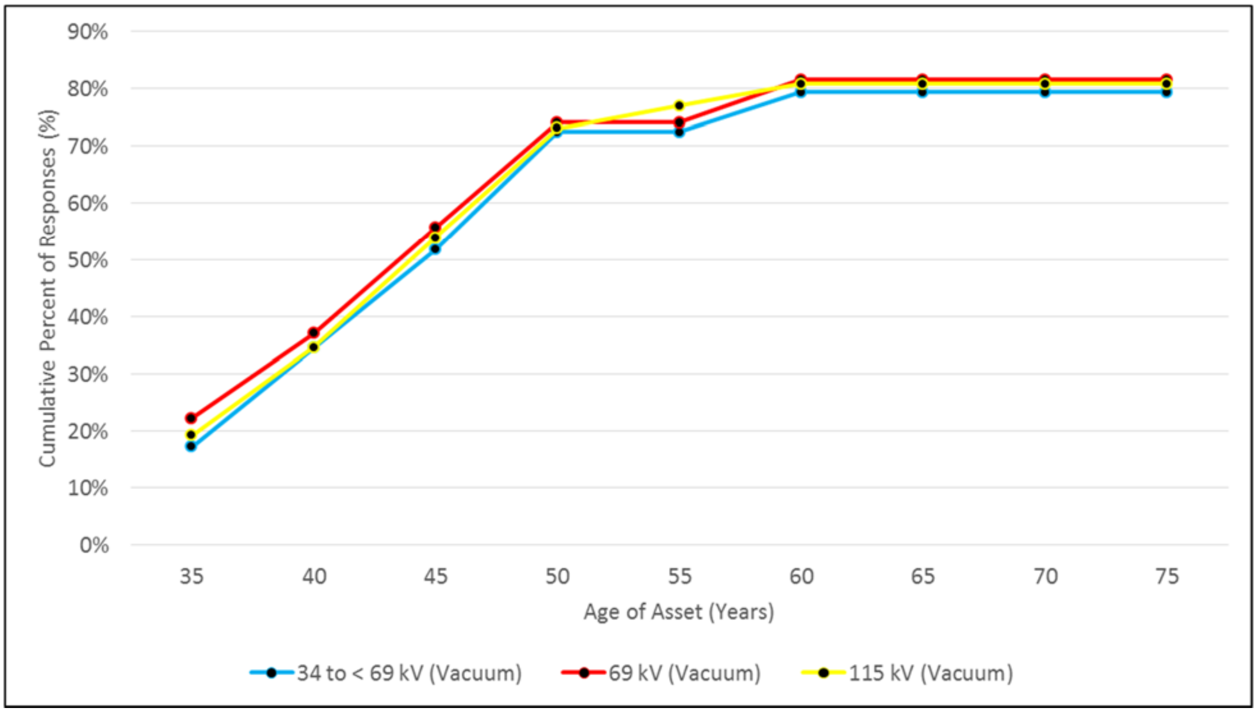

Figure 3-9
Age of Concern: Cumulative Percentage – 34kV to 115kV Gas Circuit Breakers

Table 3-3
Age of Concern about Leaving in Service: Vacuum Circuit Breakers

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Run to Failure
34 to < 69 kV (Vacuum)	17%	17%	17%	21%	0%	7%	0%	0%	0%	21%
69 kV (Vacuum)	22%	15%	19%	19%	0%	7%	0%	0%	0%	19%
115 kV (Vacuum)	19%	15%	19%	19%	4%	4%	0%	0%	0%	19%

Oil Breakers: Age of Getting Very Concerned

Respondents were then asked at what ages they would start getting *very* concerned about leaving breakers in service, by interrupting media and voltage level.

Figure 3-10, Figure 3-11, Figure 3-12 and Table 3-4 show responses to the question, "For the following oil circuit breaker voltage levels, at what age would you start getting very concerned about leaving the asset in service (ideally target for planned replacement in the next 2 to 5 years)?

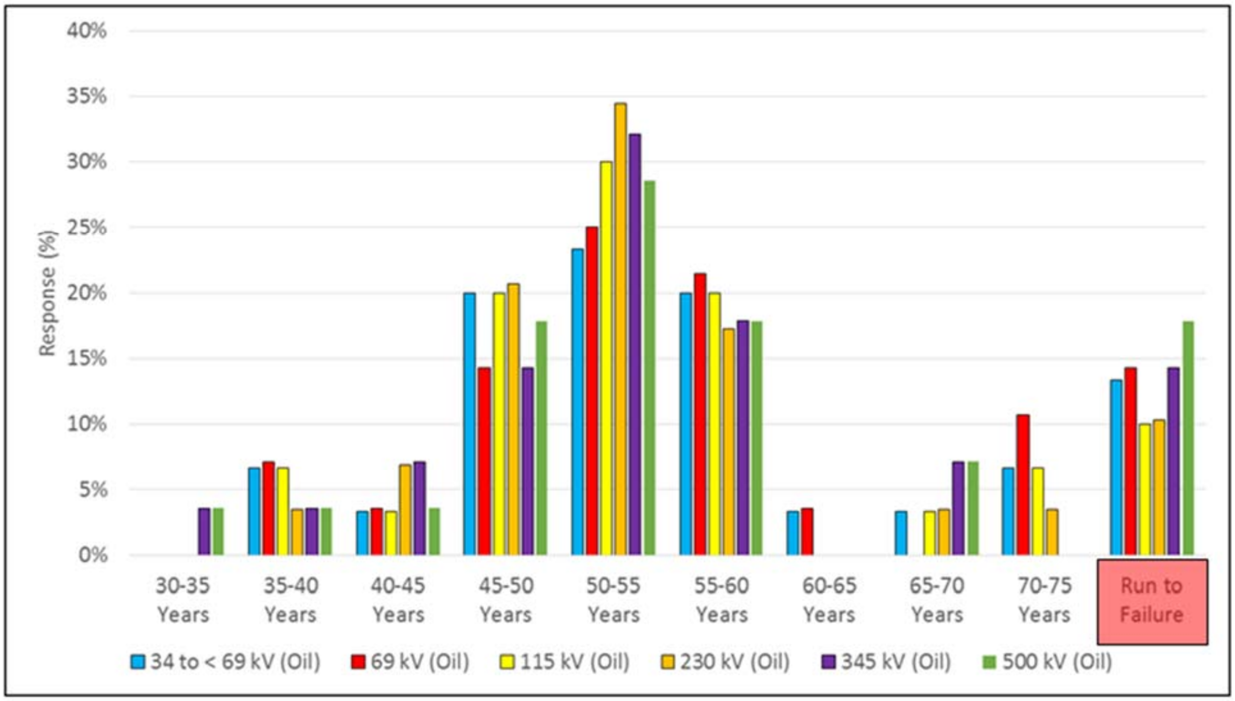

Figure 3-10
Age of Getting Very Concerned about Leaving Breaker in Service: Oil Breakers

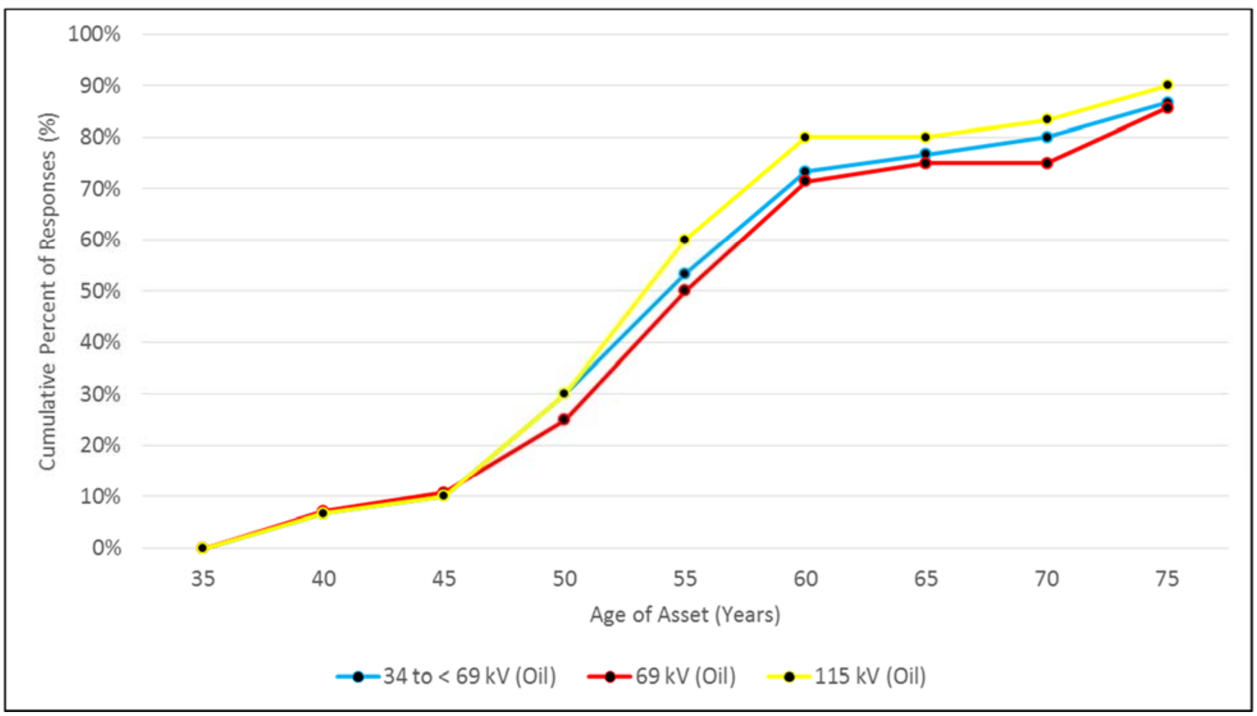

Figure 3-11
Cumulative Percentage – Age of Getting Very Concerned: 34kV to 115kV Oil Circuit Breakers

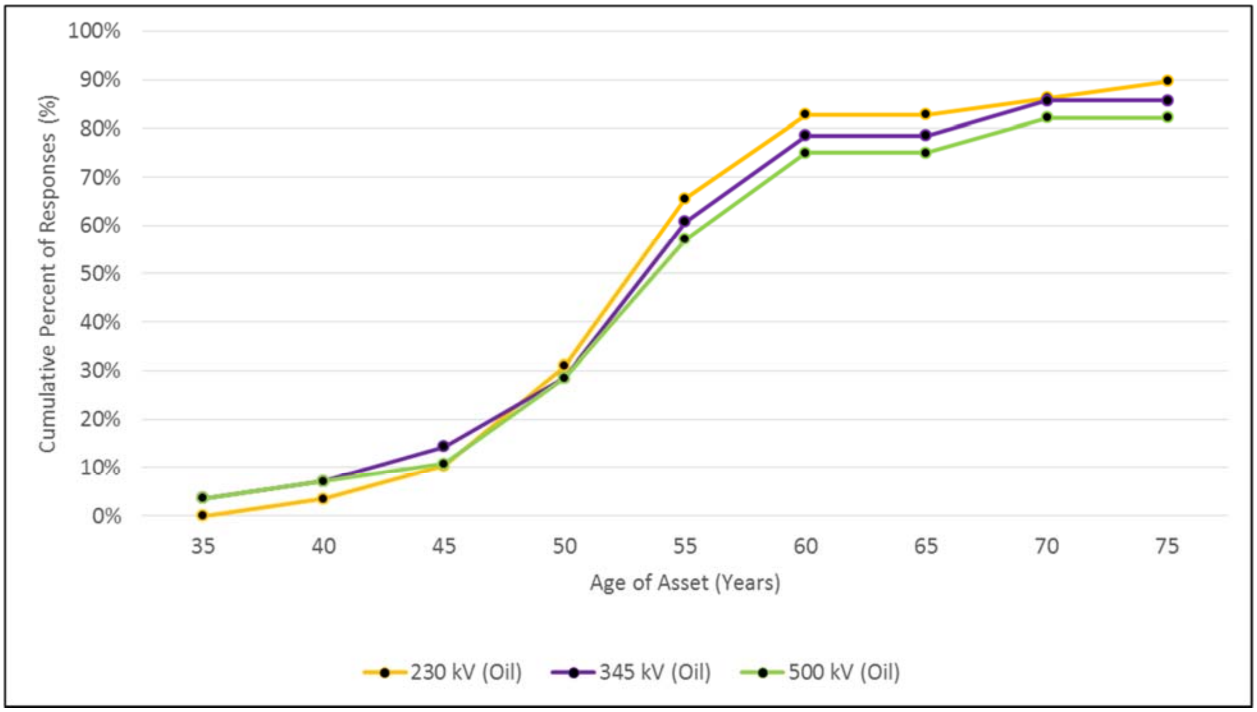

Figure 3-12
Cumulative Percentage – Age of Getting <u>Very</u> Concerned: 230kV to 500kV Oil Circuit Breakers

Table 3-4
Age of Getting Very Concerned about Leaving Breaker in Service: Oil Breakers

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Run to Failure
34 to < 69 kV (Oil)	0%	7%	3%	20%	23%	20%	3%	3%	7%	13%
69 kV (Oil)	0%	7%	4%	14%	25%	21%	4%	0%	11%	14%
115 kV (Oil)	0%	7%	3%	20%	30%	20%	0%	3%	7%	10%
230 kV (Oil)	0%	3%	7%	21%	34%	17%	0%	3%	3%	10%
345 kV (Oil)	4%	4%	7%	14%	32%	18%	0%	7%	0%	14%
500 kV (Oil)	4%	4%	4%	18%	29%	18%	0%	7%	0%	18%

Gas Breakers: Age of Getting Very Concerned

Figure 3-13, Figure 3-14, Figure 3-15 and Table 3-5 show responses to the question, *"For the following <u>gas</u> circuit breaker voltage levels, at what age would you start getting <u>very</u> concerned about leaving the asset in service (ideally target for planned replacement in the next 2 to 5 years)?"*

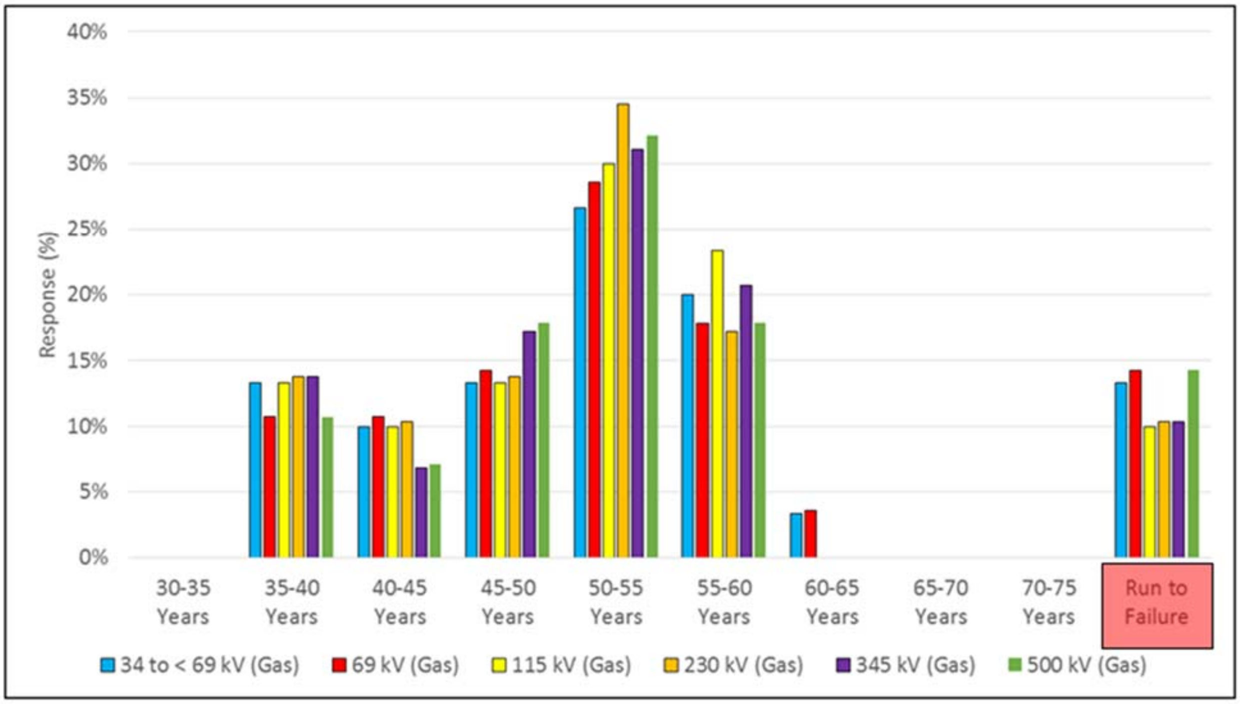

Figure 3-13
Age of Getting Very Concerned about Leaving Breaker in Service: Gas Breakers

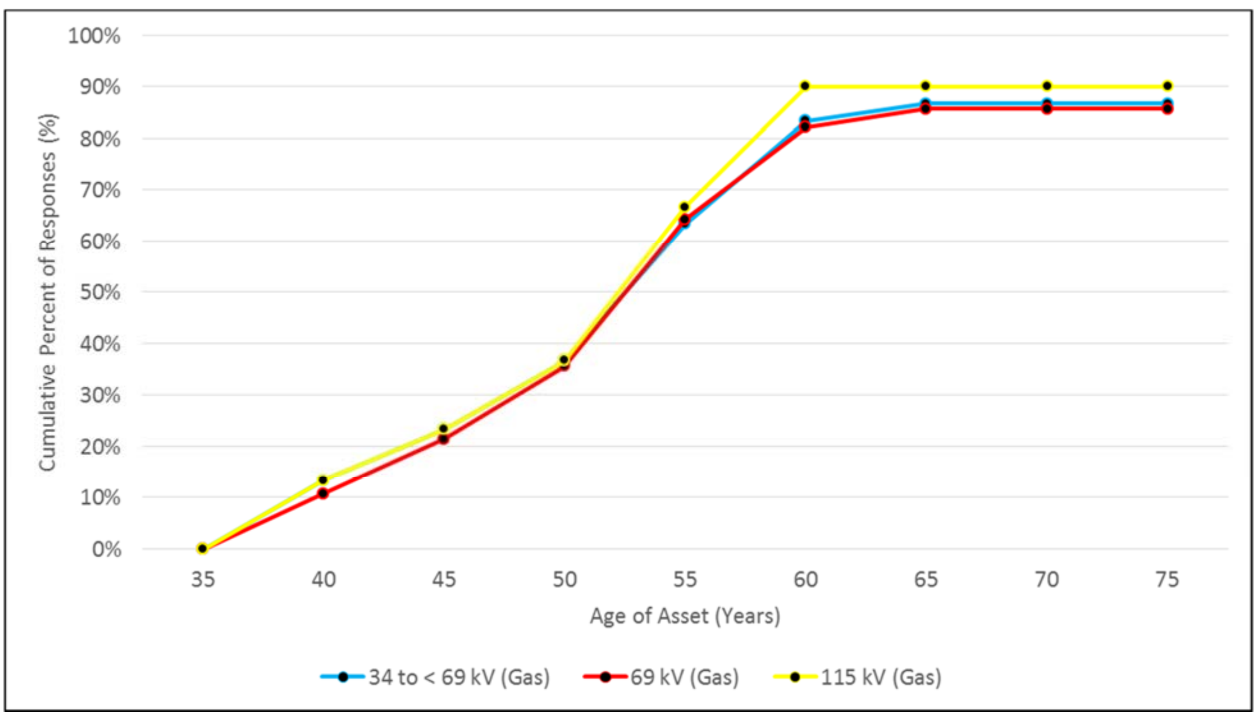

Figure 3-14
Cumulative Percentage – Age of Getting Very Concerned: 34kV to 115kV Gas Circuit Breakers

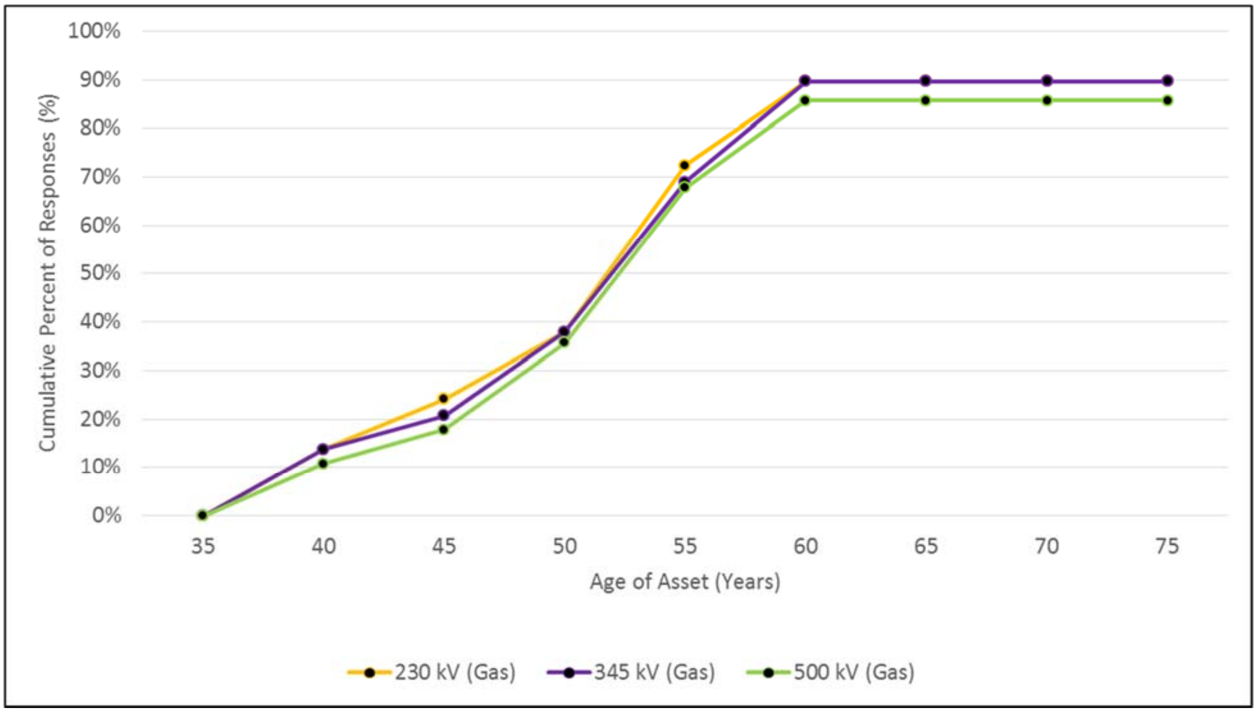

Figure 3-15
Cumulative Percentage – Age of Getting Very Concerned: 230kV to 500kV Gas Circuit Breakers

Table 3-5
Age of Getting Very Concerned about Leaving Breaker in Service: Gas Breakers

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Run to Failure
34 to < 69 kV (Gas)	0%	13%	10%	13%	27%	20%	3%	0%	0%	13%
69 kV (Gas)	0%	11%	11%	14%	29%	18%	4%	0%	0%	14%
115 kV (Gas)	0%	13%	10%	13%	30%	23%	0%	0%	0%	10%
230 kV (Gas)	0%	14%	10%	14%	34%	17%	0%	0%	0%	10%
345 kV (Gas)	0%	14%	7%	17%	31%	21%	0%	0%	0%	10%
500 kV (Gas)	0%	11%	7%	18%	32%	18%	0%	0%	0%	14%

Vacuum Breakers: Age of Getting Very Concerned

Figure 3-16, Figure 3-17 and Table 3-6 show responses to the question, *"For the following vacuum circuit breaker voltage levels, at what age would you start getting very concerned about leaving the asset in service (ideally target for planned replacement in the next 2 to 5 years)?"*

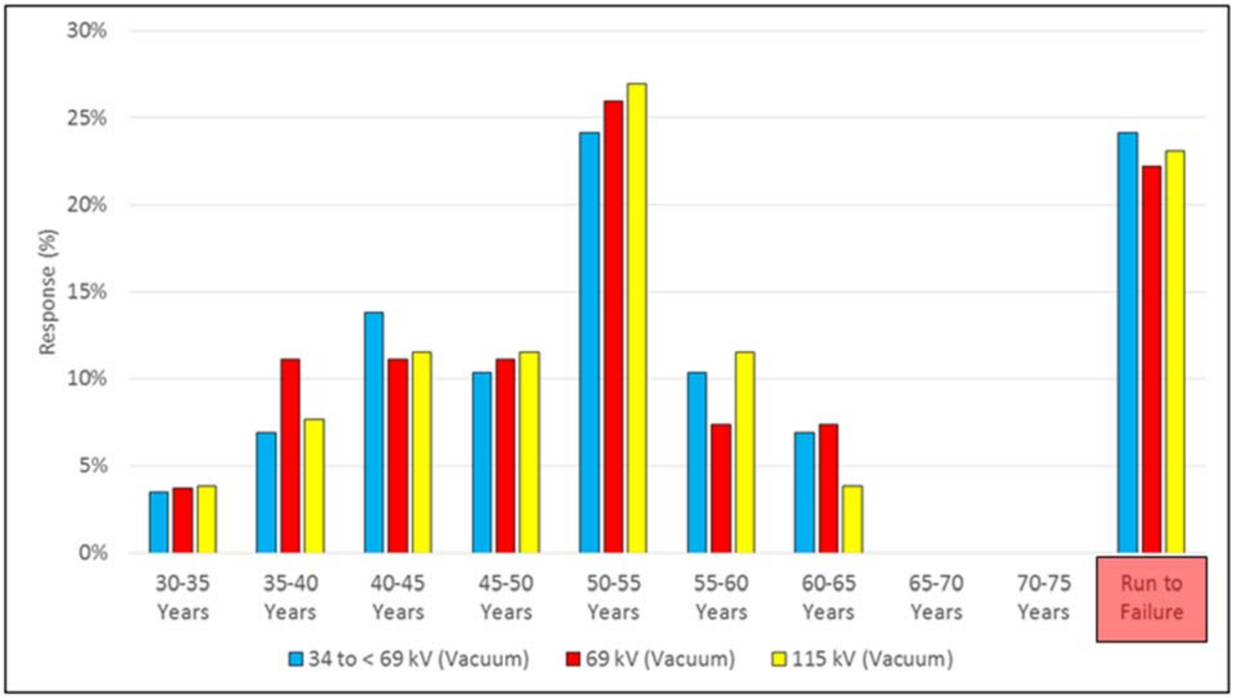

Figure 3-16
Age of Getting Very Concerned about Leaving Breaker in Service: Vacuum Breakers

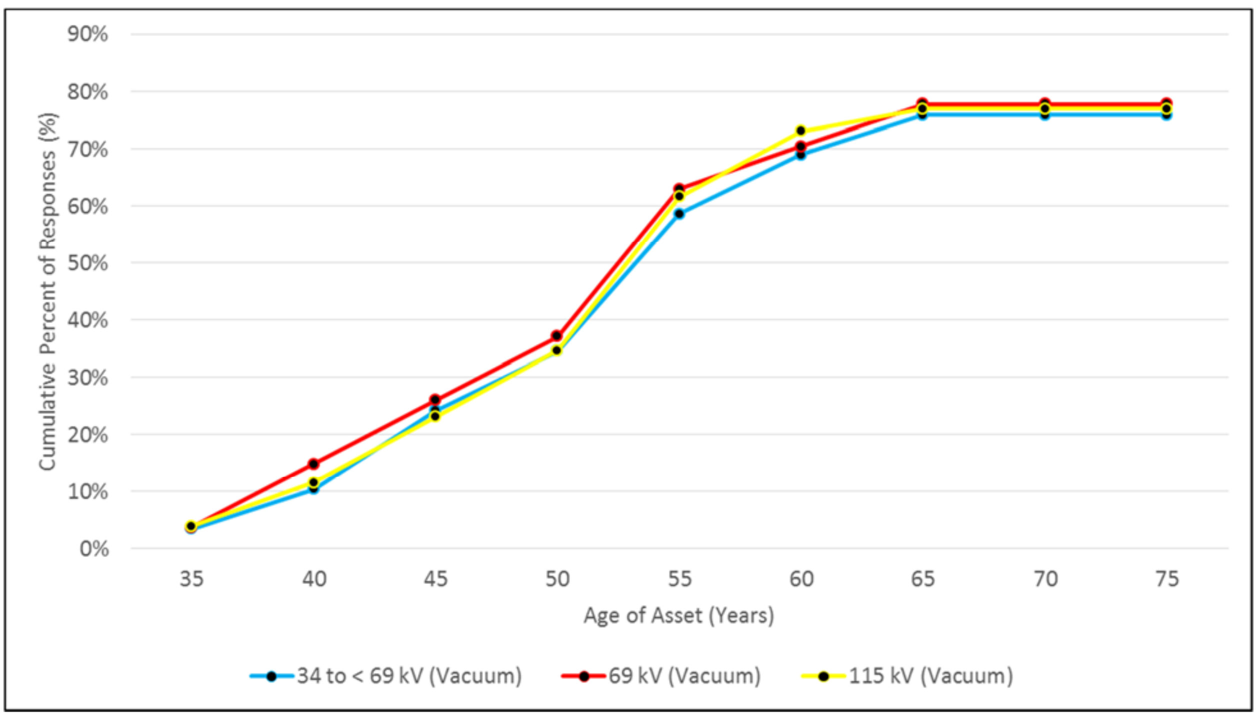

Figure 3-17
Cumulative Percentage – Age of Getting Very Concerned: 34kV to 115kV Vacuum Circuit Breakers

Table 3-6
Age of Getting Very Concerned about Leaving Breaker in Service: Vacuum Breakers

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Run to Failure
34 to < 69 kV (Vacuum)	3%	7%	14%	10%	24%	10%	7%	0%	0%	24%
69 kV (Vacuum)	4%	11%	11%	11%	26%	7%	7%	0%	0%	22%
115 kV (Vacuum)	4%	8%	12%	12%	27%	12%	4%	0%	0%	23%

4
ASSESSMENT AND REPLACEMENT PRACTICES FOR CIRCUIT BREAKERS

Survey participants were asked a series of questions about their practices regarding assessment and replacement of breakers. Responses are presented in this chapter.

Running to Failure

Question: "*Does your company typically run a transmission circuit breaker to failure (i.e., it becomes inoperable and/or too impractical or expensive to restore to operation)?"*

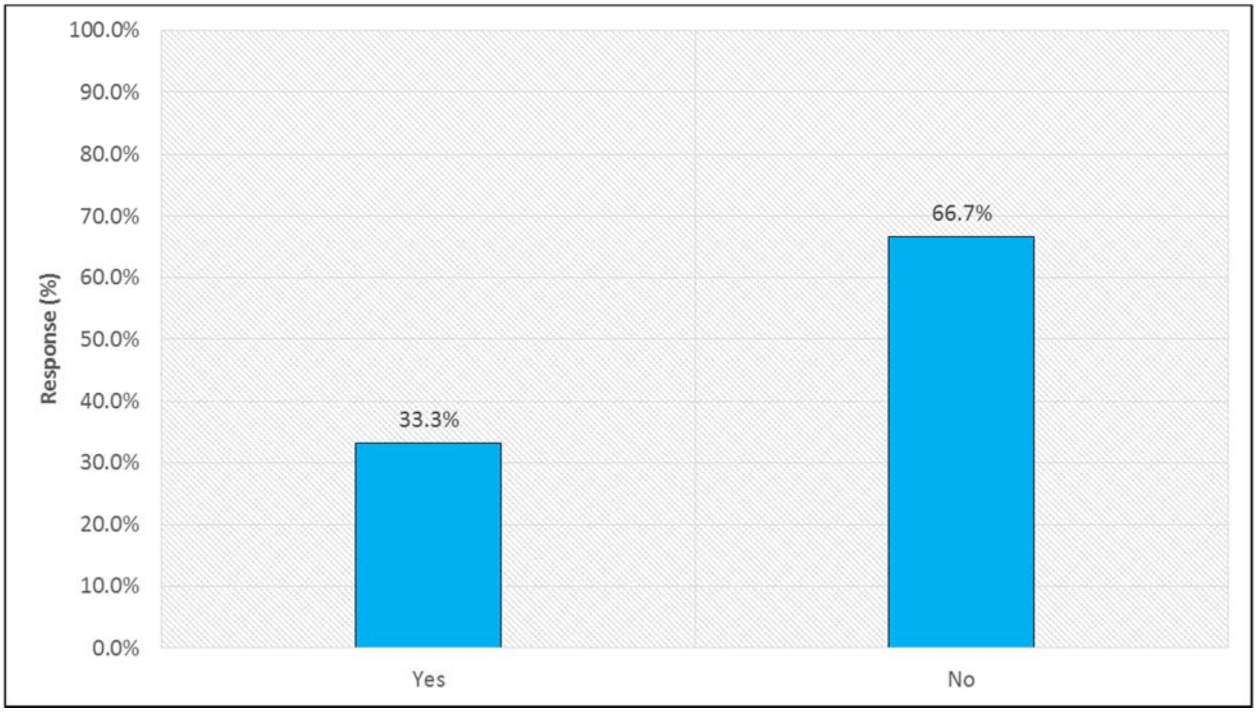

Figure 4-1
Run to Failure?

Replacement Criteria

"Please rank each of the following criteria you use to replace an asset. (Rank 1-7 with 7 being most critical.)"

Table 4-1
Ranking Replacement Criteria Averages

Criteria	Ranking Average
Safety	5.41
Condition	5.05
Reliability/Availability	4.73
Ownership Costs (Maintenance, unavailability of skills, availability of spares, etc.)	3.82
Age	3.82
Environmental Impact	3.19
Asset Health Index/Trigger	2.33

"Please comment if there are any other criteria you use to replace an asset?"

> "Overstressed interrupting rating due to increased fault current."
>
> "We don't currently have an asset health index built yet, we replace assets based on condition/age and availability of spare parts through a capital planning process. If there is a reliability or availability issue, they rise to the top. Safety and environmental are important factors when deciding to replace as well."
>
> "SME determination of when to replace."

Process or Algorithm to Assess Condition

Asked if they had a formal process or algorithm to assess circuit breaker condition, respondents provided the answers shown in Figure 4-2.

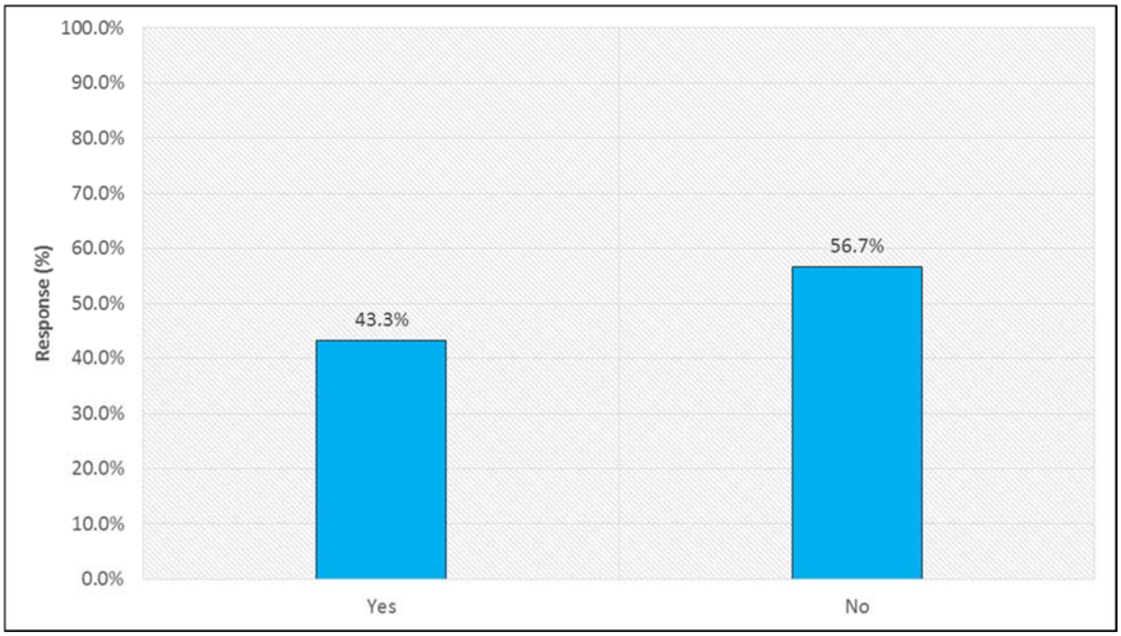

Figure 4-2
Do you have a formal process or algorithm to assess circuit breaker condition?

Respondents who answered yes then were asked to describe the process or algorithm. Their answers are shown in Figure 4-3.

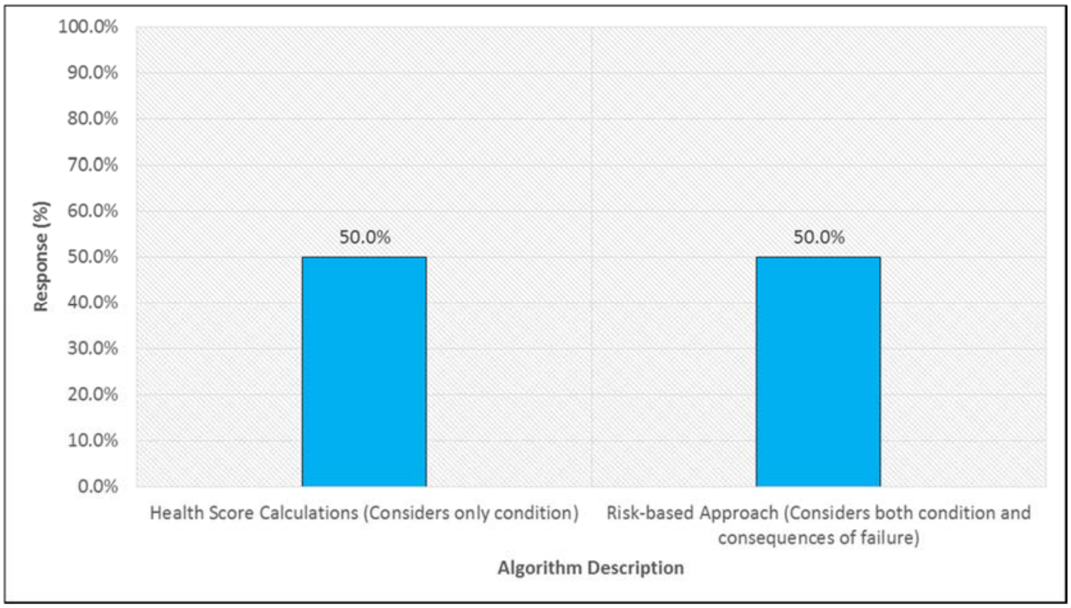

Figure 4-3
How would you best describe the formal process or algorithm to assess breaker condition?

Asked if their algorithm could trigger a replacement by itself, respondents provided answers shown in Figure 4-4.

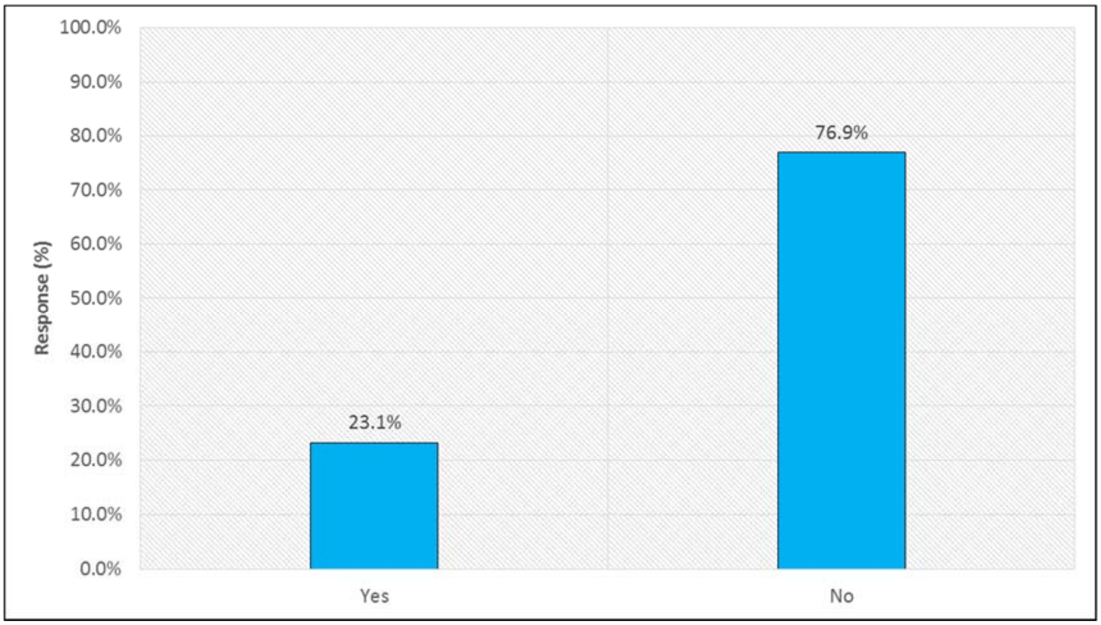

Figure 4-4
Could your algorithm trigger a replacement by itself?

Respondents were asked to provide additional comments if other factors were required, shown below.

"Decision is made using variety of factors including redundancy, spare availability, risk etc."

"The algorithm's health score output will be used in the decision to replace the CB, but there are many other factors that are taken into account before the final decision to replace the CB is made. Also, a data review of the maintenance and test data as well as a site inspection is completed on the asset(s) to confirm the algorithm's output."

> "Under development."
>
> "No. Algorithm trigger development of a mitigation plan, which may include replacement."
>
> "Other PM test conditions."
>
> "Number of operations, Historical Corrective Maintenance work performed and Fault Duty Assessment."
>
> "Use health information to develop an investment strategy."
>
> "The algorithm is taken into account when determining replacement."
>
> "Reliability & Feedback from field personnel."

Replacement by Type Regardless of Age or Condition

Respondents were asked if they replaced some circuit breakers by type or family regardless of age or condition. Figure 4-5 shows their answers.

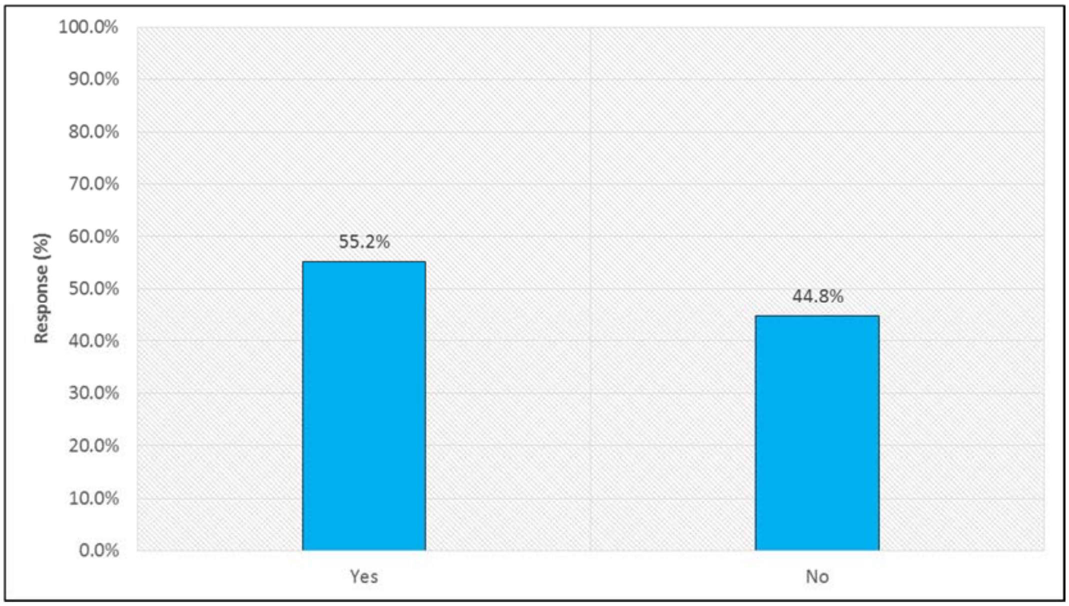

Figure 4-5
Do you replace circuit breakers by type or family regardless of age or condition (e.g., OCBs, air-blast)?

Asked to provide a list of the types of families that they had replaced regardless of age or condition, respondents answered as follows:

- Live Tank
- Interrupt rating
- Asbestos-containing ABCBs
- Distribution class OCBs
- Oil, Air Blast, Magnetic
- Westinghouse 345OSF25000, Westinghouse 345SP-40-2000, Westinghouse 362SFA40; all of which are 345-kV 1970's vintage SF6 breakers
- "SF". "SFA", "ATB", "GA", "GB", "PK", "FX", "HVB (early vintages)

Fleet Replacement Decisions

Figure 4-6 shows responses to the question, *"How do you decide when to replace a population (or fleet) of assets? (Programmatic replacement) (Select all that apply)."*

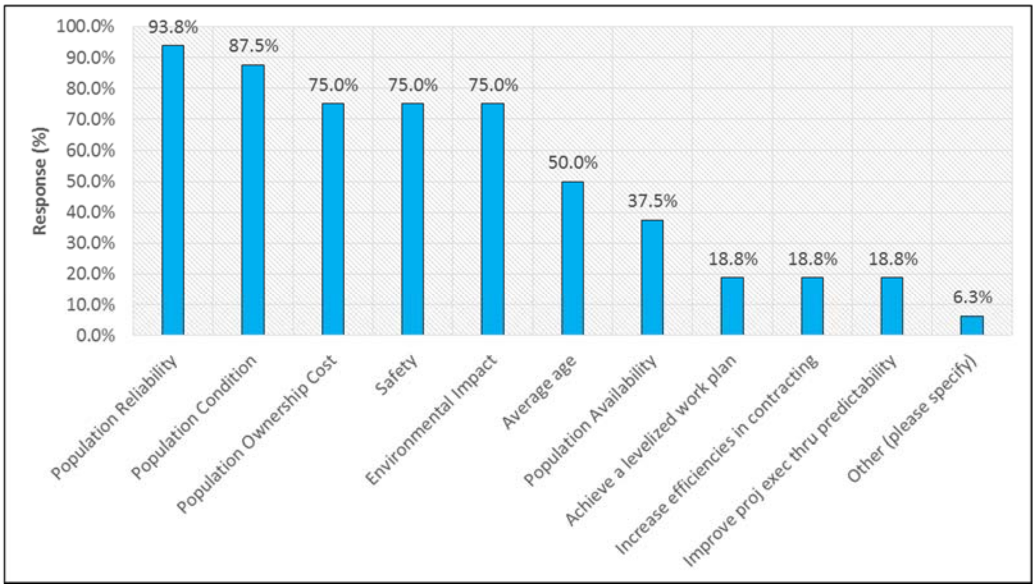

Figure 4-6
How do you decide when to replace a population (or fleet) of assets?

When asked, *Do you restrict your use of stand-alone breakers to air insulated substations?*, respondents answered as shown in Figure 4-7.

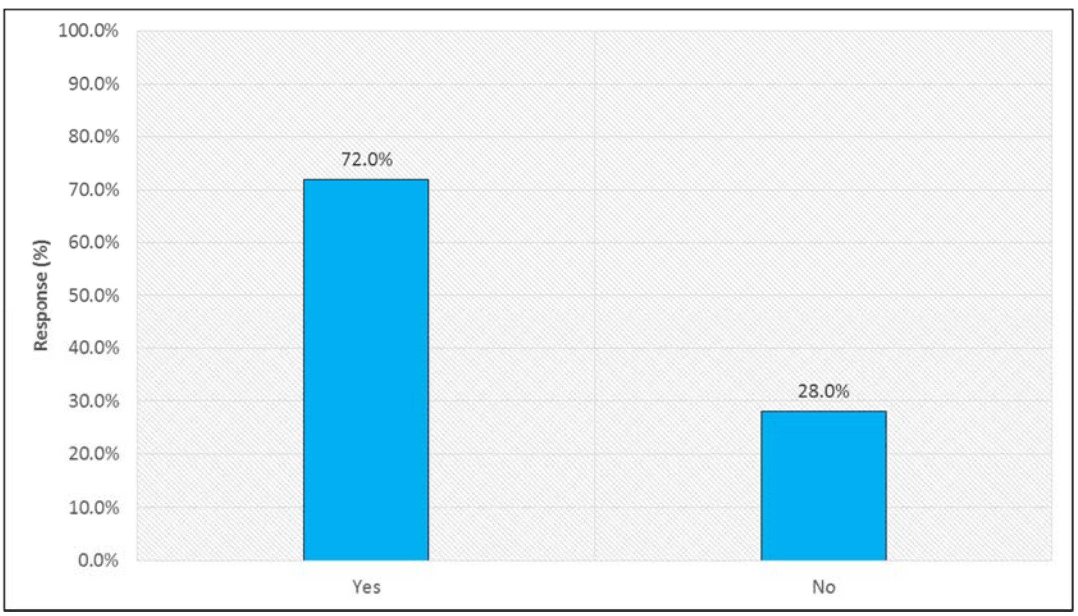

Figure 4-7
Do you restrict your use of stand-alone breakers to air insulated substations?

Other Equipment Replacement

Question: *When replacing a breaker, what other equipment is replaced? (Select all that apply)*

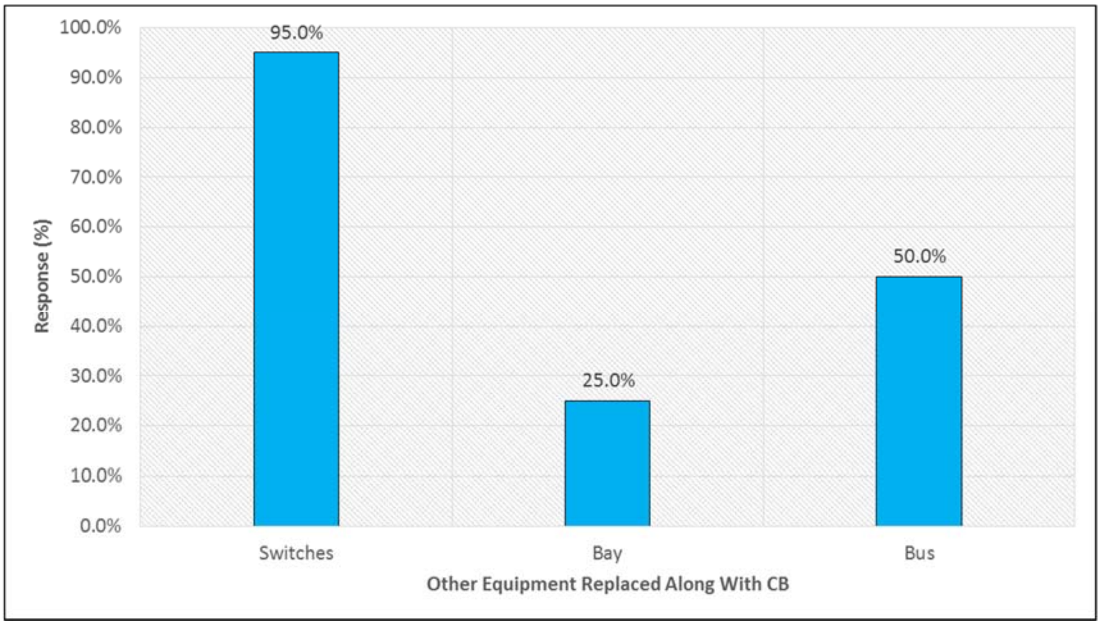

Figure 4-8
Other Equipment Replaced Along with Circuit Breaker

Drivers for Replacement Project Scope Expansion

Question: *If you expand the scope of a replacement project, what are the drivers? (Select all that apply)*

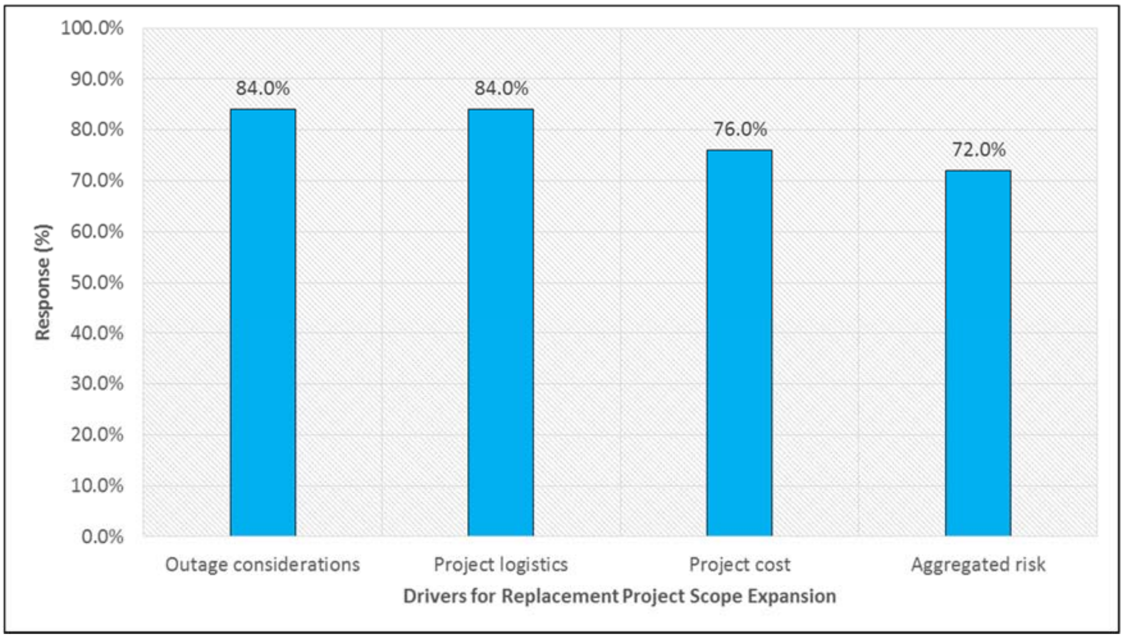

Figure 4-9
Drivers for Replacement Project Scope Expansion

5

SURVEY RESPONDENT CHARACTERISTICS: TRANSFORMERS

To help place the survey results in context and better interpret the responses, the characteristics of the utility participants and their respective transformer fleets are presented in this chapter.

Transformer Survey

Job Classification

Each transmission survey respondent was classified by job description as shown in Figure 5-1.

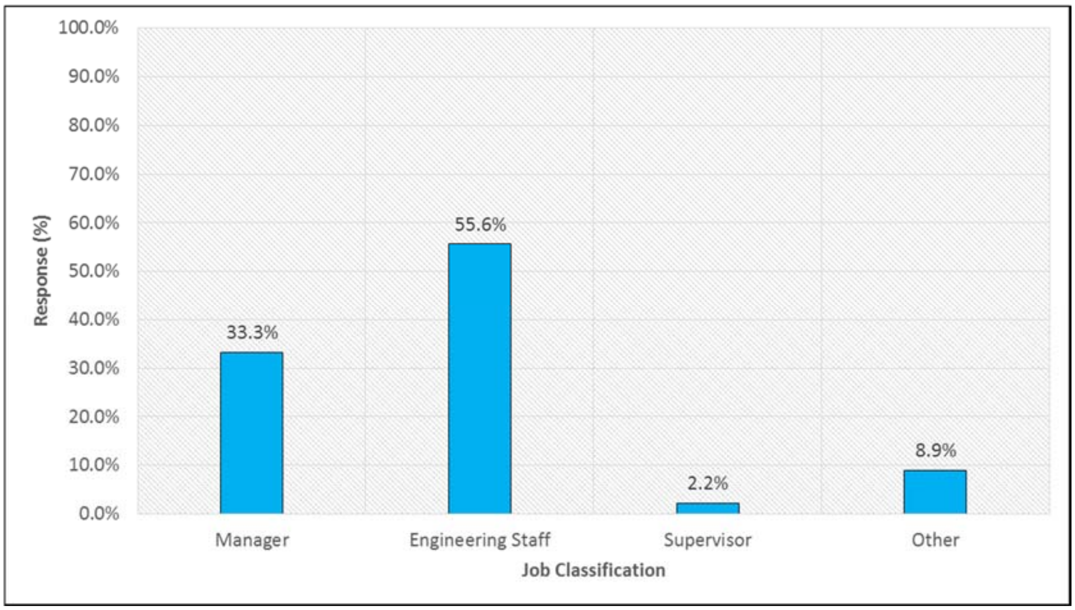

Figure 5-1
Job Classification: Transformer Survey Respondents

Organization Classification

Each respondent was classified by organization function and company description, as presented in Figures 5-2 and 5-3.

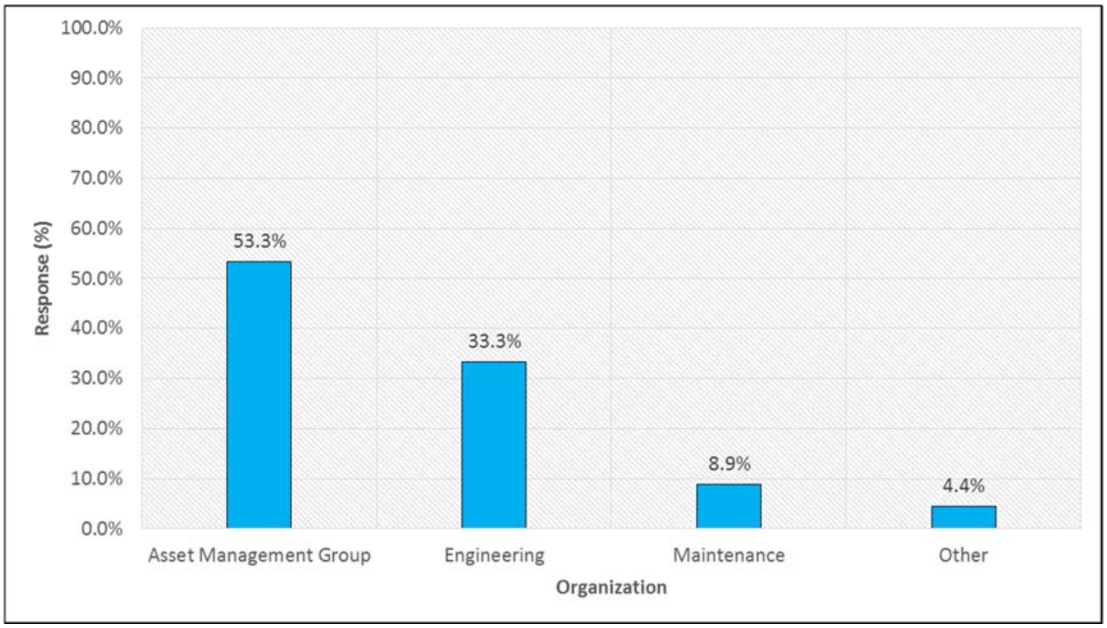

Figure 5-2
Organization Classification

Company Description

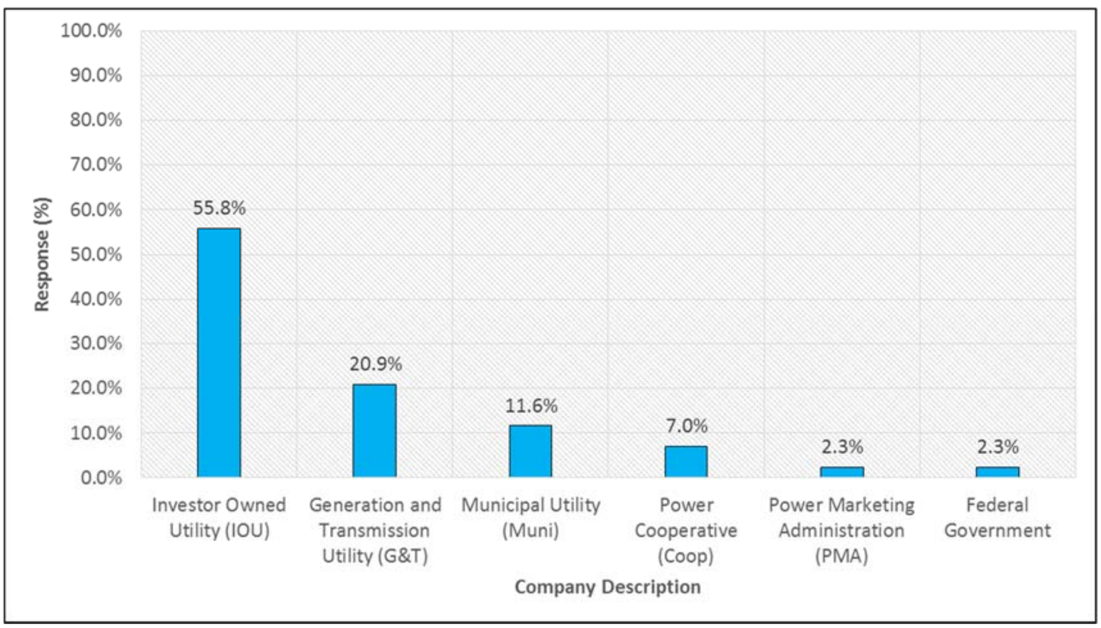

Figure 5-3
Company Description

Regulatory Structure

Respondents were asked about their company's regulatory structure. Responses are shown in Figure 5-4.

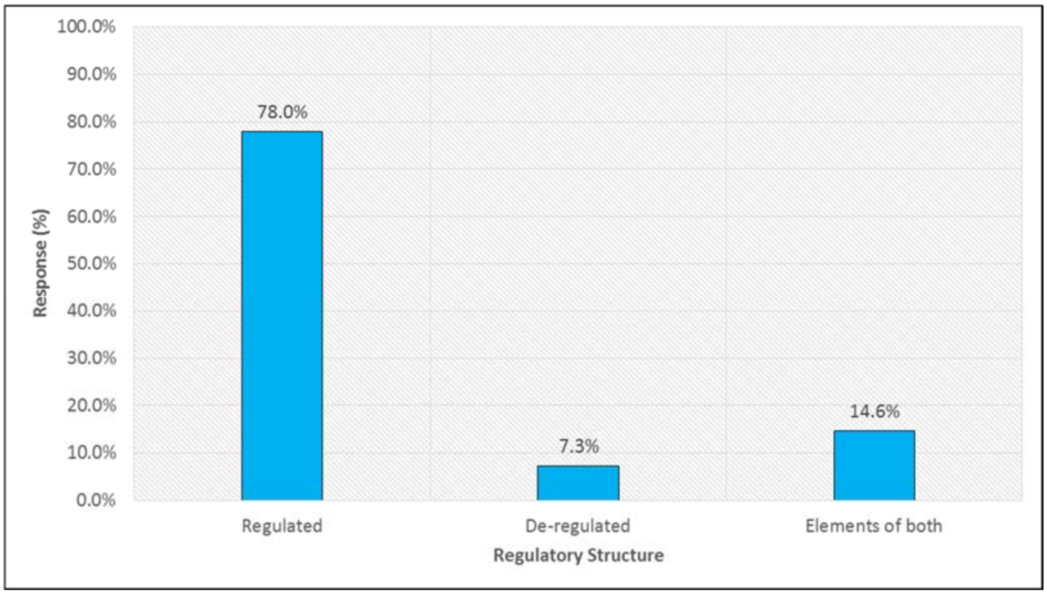

Figure 5-4
Regulatory Structure

Asked what assets their companies owned, respondents provided the information presented in Table 5-1. "None" means the respondent had none of that category. Whereas, "Part of Core Business" means the respondent considered that category to be a core business activity. Consider "Distribution" as an example. 6.7% of the respondents had no distribution assets. 71.1% considered distribution to be a core business. The balance had some distribution but did not consider it to be a core activity.

	None	Part of Core Business
Generation	26.7%	66.7%
Transmission	4.4%	88.9%
Distribution	6.7%	71.1%

Table 5-1
Assets Owned

System and Fleet Characteristics

Peak Load

Respondents were asked to define their system's peak load. Results are shown in Figure 5-5.

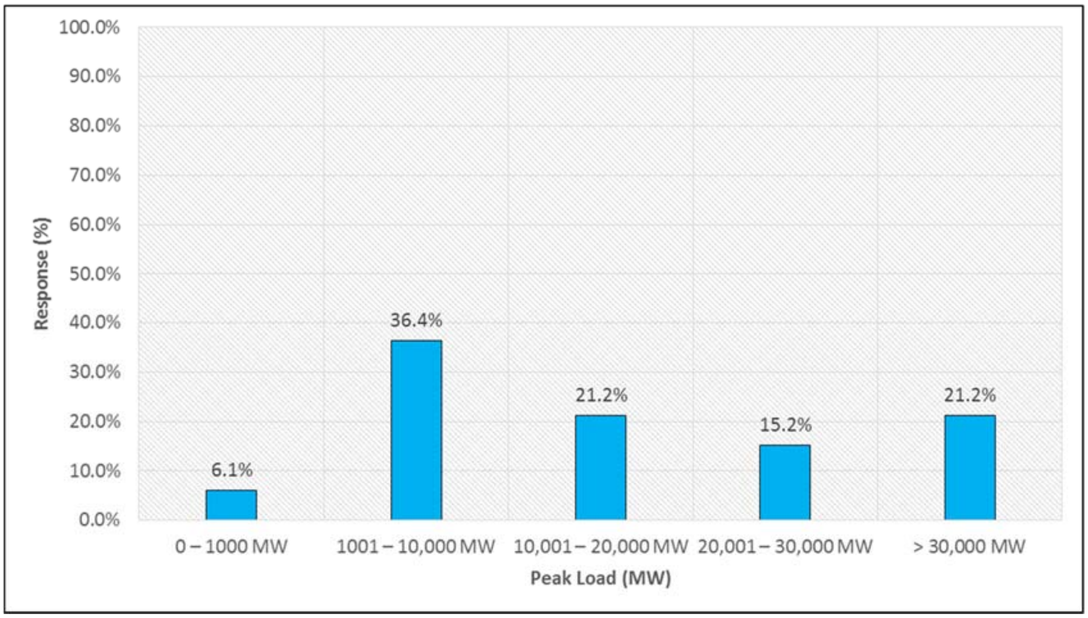

Figure 5-5
Peak Load

Number of Transformers in Service

Respondents were asked how many transmission transformers (>= 34 kV) they had in service. Figure 5-6 shows results.

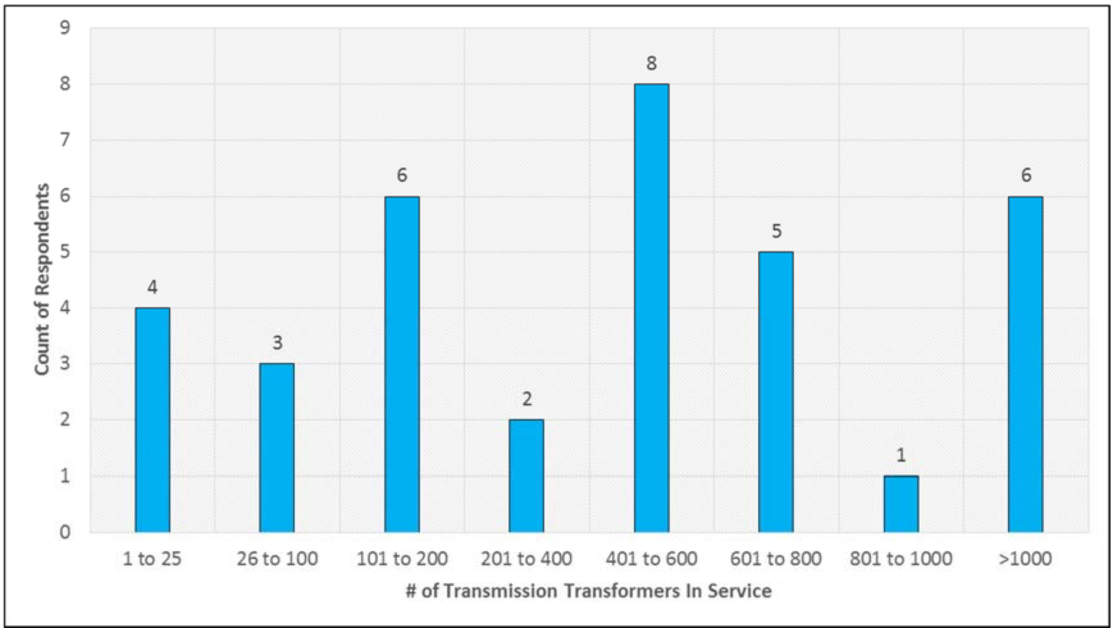

Figure 5-6
Number of Transmission Transformers in Service

Age Breakdown

What is the age breakdown of your transmission transformer fleet?

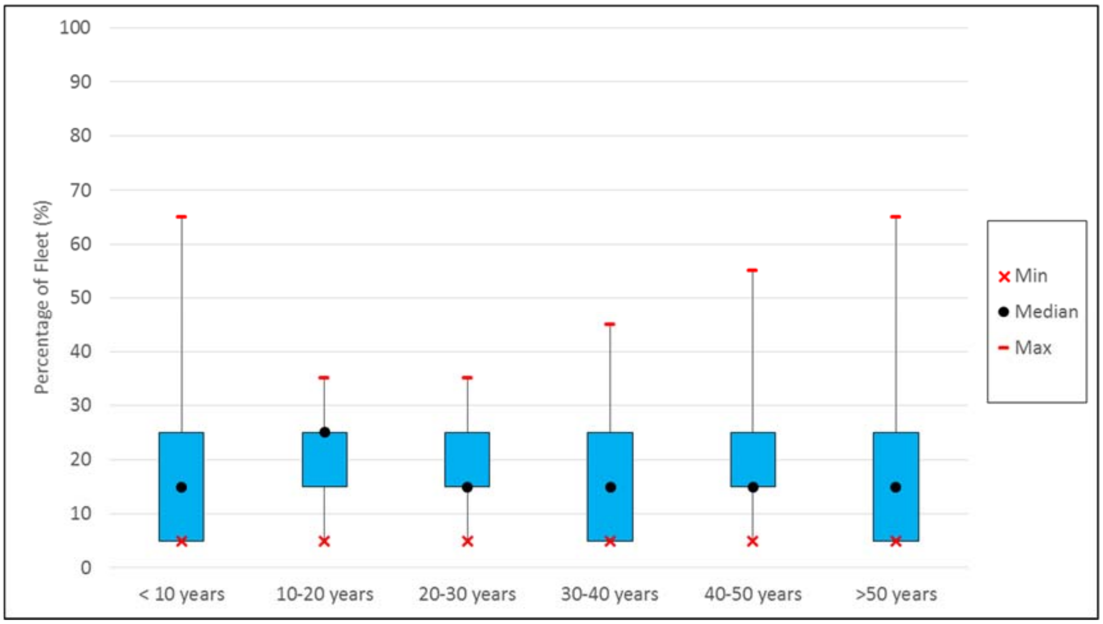

Figure 5-7
Transformer Fleet Age Breakdown

6
END OF LIFE CONCERNS FOR TRANSFORMERS

End of Life (EOL) Definitions

Utilities use different terms to define the end of life and expected service life of assets. For example, Hydro One uses the following definitions:

End of Life (EOL): The high likelihood of failure, or loss of an asset's ability to provide the intended functionality as determined through diagnostic data, wherein the failure or loss of functionality would cause unacceptable consequences. EOL can be further divided into three sub-categories:

- **Technical EOL**: The asset has failed, or condition assessment data indicates it is likely to do so, or it can no longer be expected to perform its function reliably
- **Economic EOL**: Unacceptable levels of maintenance costs are required to achieve the required performance/function.
- **Strategic EOL**: Necessary spares parts or skills set are unavailable; or the forecast loading or short circuit levels have exceeded the rating of the asset.

Expected Service life (ESL): The average time in years that an asset can be expected to operate under normal system conditions.

Use of Definitions and Utility Comments

Transformer survey respondents were asked whether their company used these or similar EOL definitions. Responses are shown in Figure 6-1.

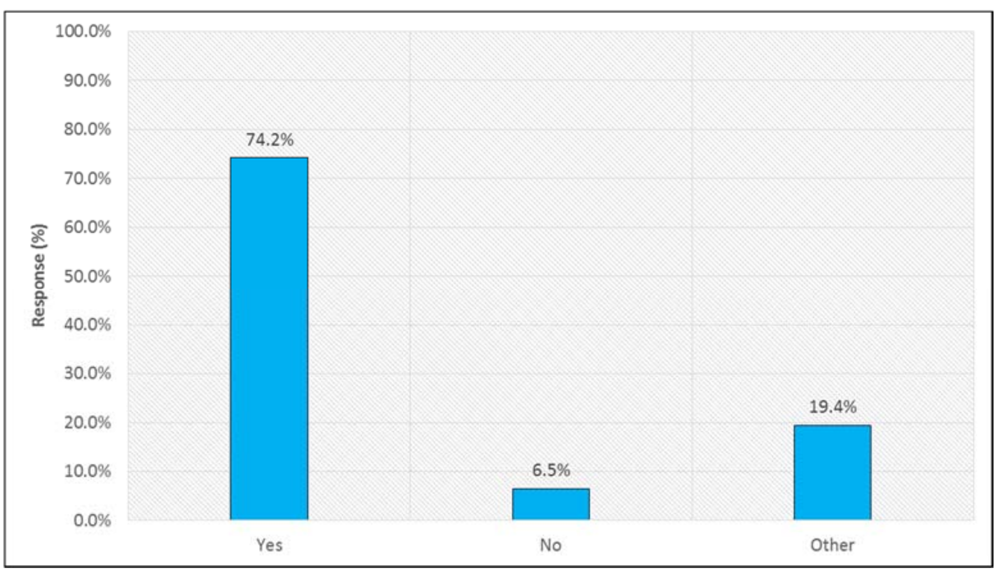

Figure 6-1
Use of Hydro One or Similar Definitions for End of Life and Expected Service Life

Comments

Respondents who answered no to this question were invited to provide comments. These are presented below.

> "Do not use these specific terms, but follow the same basic definitions."
>
> "We use these criteria, but not as formal definitions or classifications."
>
> "In general:
>
> - End of Life: The asset has failed, or condition assessment data indicates it is likely to do so, or it can no longer be expected to perform its function reliably.
> - Part Obsolescence: Necessary spares parts or skills set are unavailable; or the forecast loading or short circuit levels have exceeded the rating of the asset. Unacceptable levels of maintenance costs are required to achieve the required performance/function."
>
> "Just Technical EOL."
>
> "Use a health index that takes into account condition assessment, maintenance history, operational history and ability to repair."

Ages of Concern about Leaving Transformers in Service

Respondents were asked the question: *For transmission transformer assets, at what age would you start getting concerned about leaving the asset in service (ideally target for planned replacement in the next 5 to 10 years)?* Responses are shown in Figure 6-2 and Table 6-1.

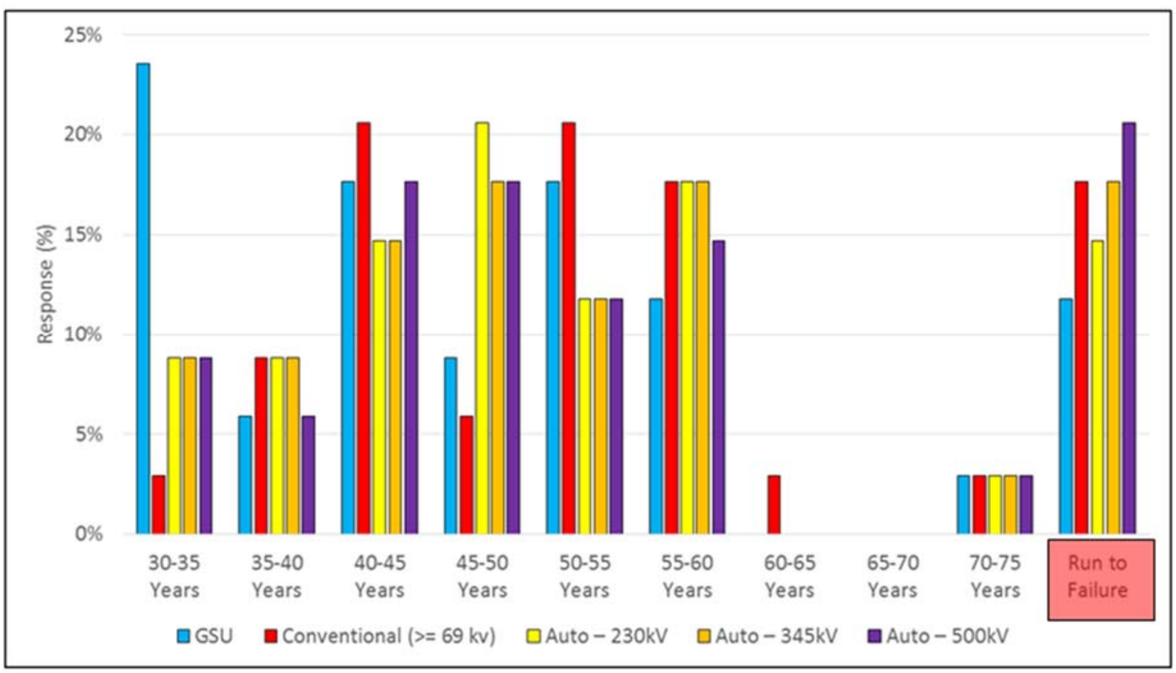

Figure 6-2
Age at Which Respondents Start Getting Concerned about Leaving Asset in Service

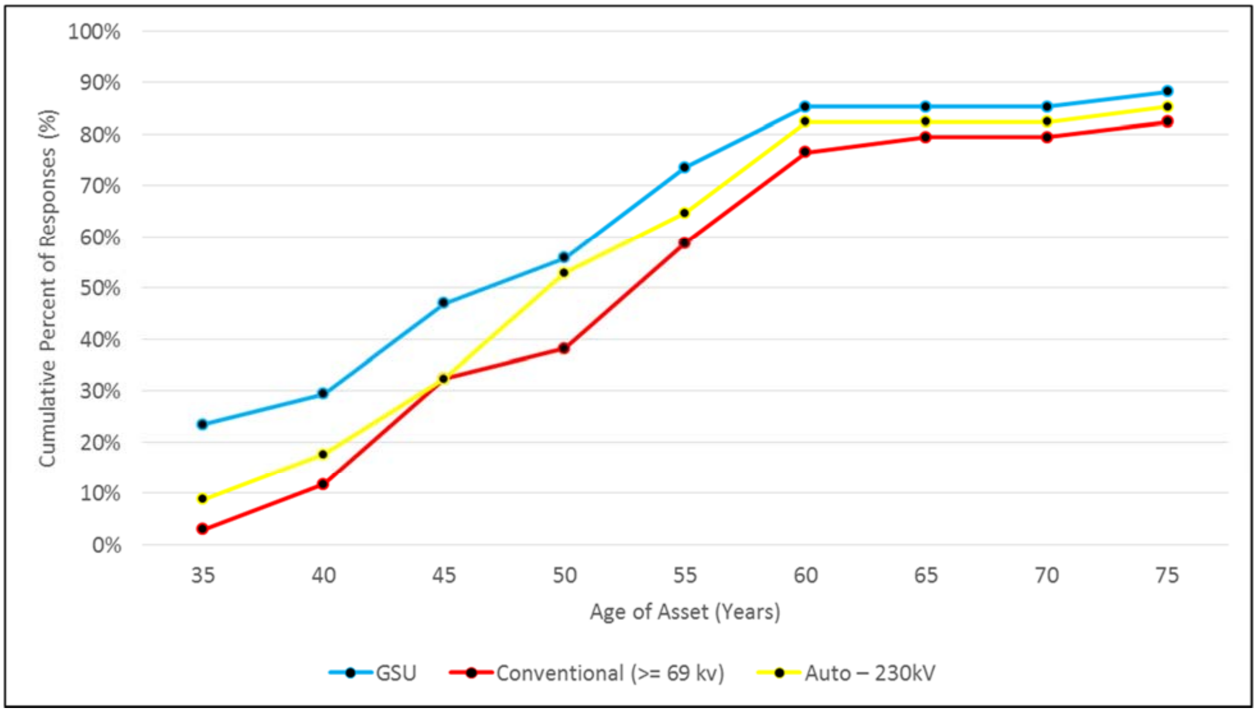

Figure 6-3
Cumulative Percentage: Age of Concern – GSU, Conventional and 230kV Auto Transformers

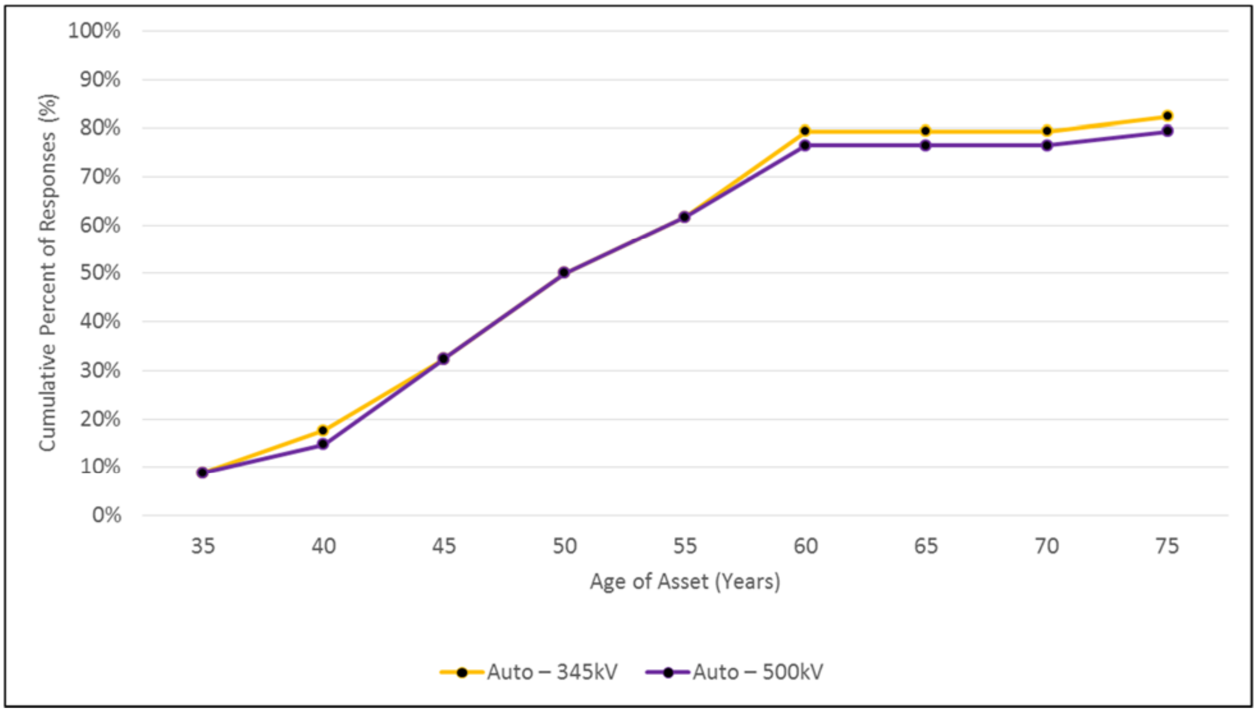

Figure 6-4
Cumulative Percentage: Age of Concern –345kV and 500kV Auto Transformers

Table 6-1
Age at Which Respondents Start Getting Concerned about Leaving Asset in Service

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Run to Failure
GSU	24%	6%	18%	9%	18%	12%	0%	0%	3%	12%
Conventional (>= 69 kv)	3%	9%	21%	6%	21%	18%	3%	0%	3%	18%
Auto – 230kV	9%	9%	15%	21%	12%	18%	0%	0%	3%	15%
Auto – 345kV	9%	9%	15%	18%	12%	18%	0%	0%	3%	18%
Auto – 500kV	9%	6%	18%	18%	12%	15%	0%	0%	3%	21%

Transformer Age at Which Respondents Become Very Concerned

For transmission transformer assets, at what age would you start getting very concerned about leaving the asset in service (ideally target for planned replacement in the next 2 to 5 years)?

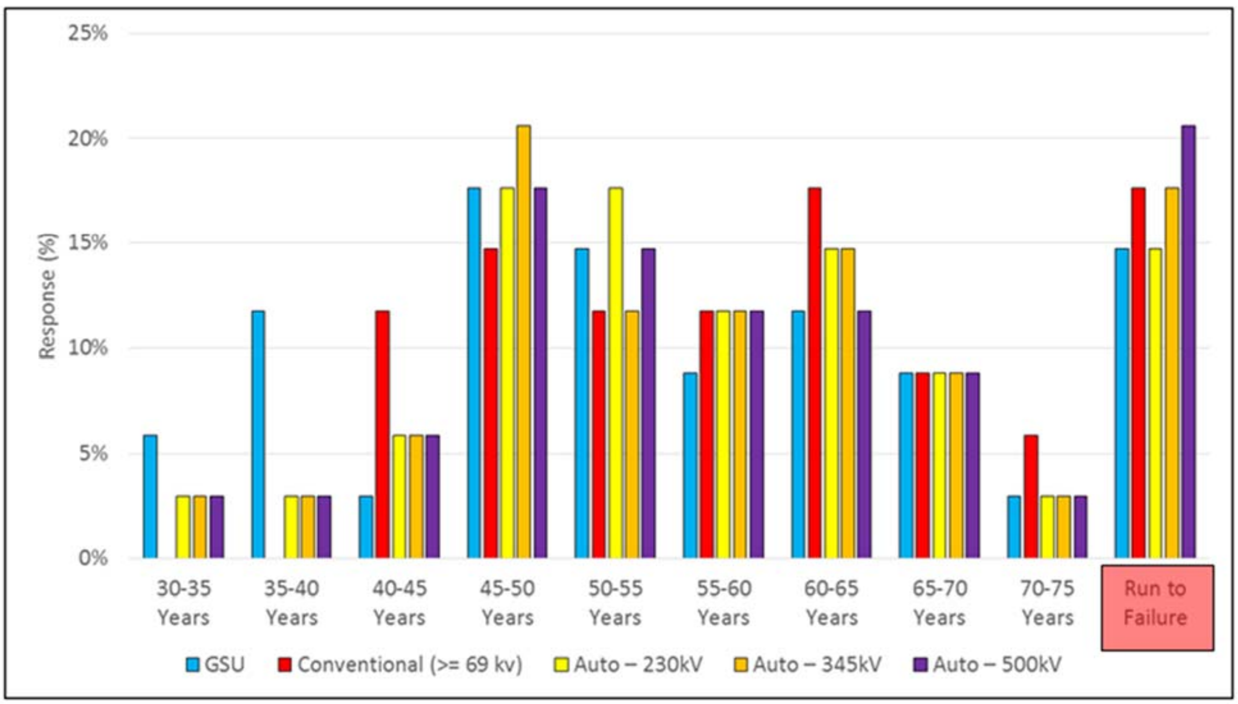

Figure 6-5
Age at Which Respondents Start Getting Very Concerned about Leaving Asset in Service

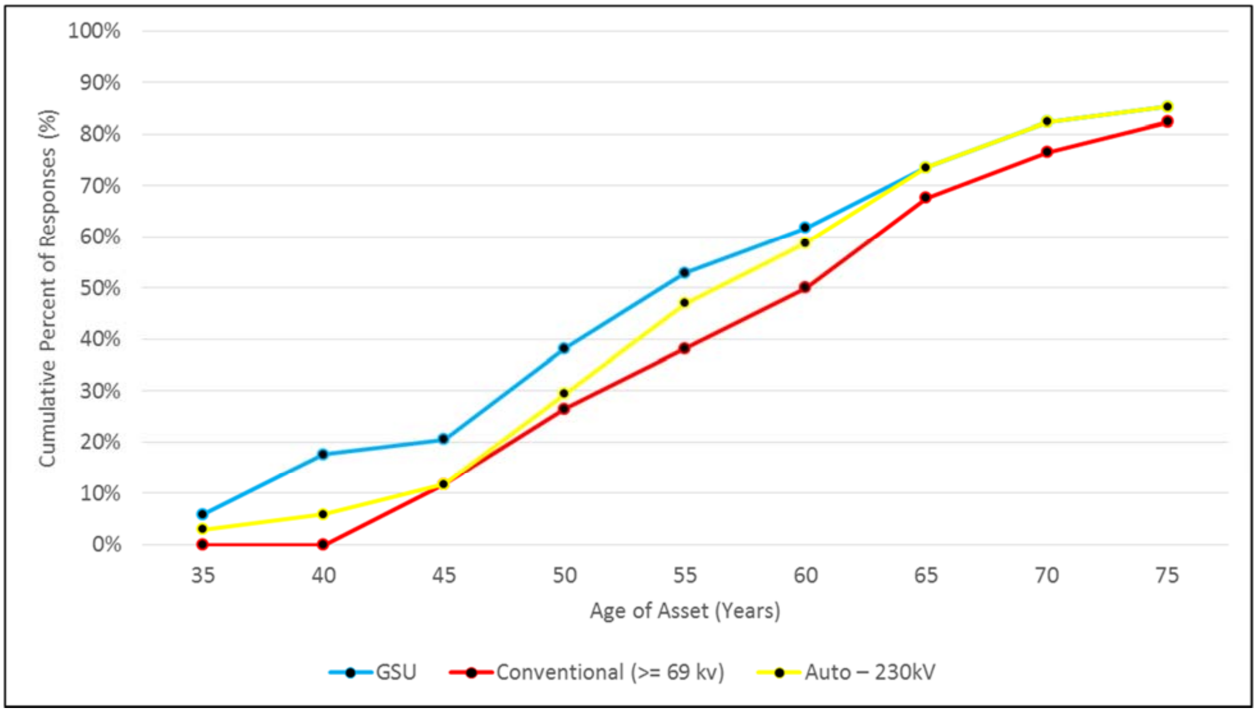

Figure 6-6
Cumulative Percentage: Age of Getting Very Concerned – GSU, Conventional, 230kV Auto Transformers

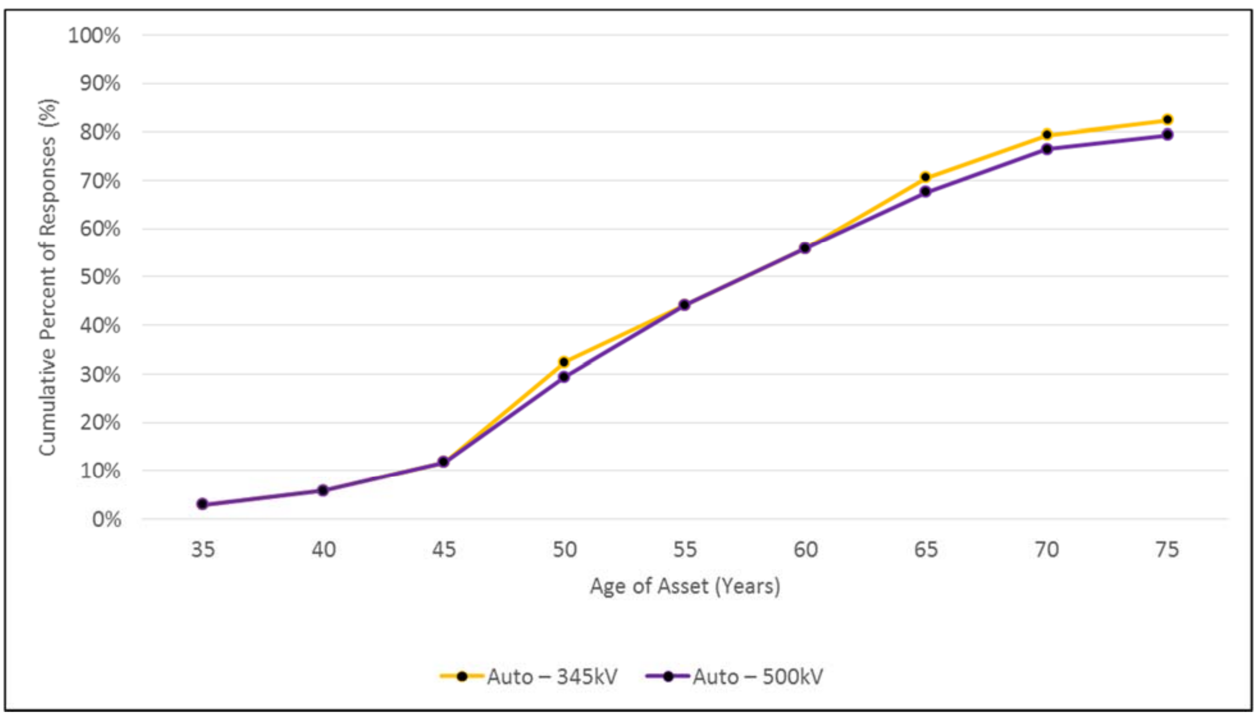

Figure 6-7
Cumulative Percentage: Age of Getting Very Concerned –345kV and 500kV Auto Transformers

Table 6-2
Age at Which Respondents Start Getting Very Concerned about Leaving Asset in Service

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Run to Failure
GSU	6%	12%	3%	18%	15%	9%	12%	9%	3%	15%
Conventional (>= 69 kv)	0%	0%	12%	15%	12%	12%	18%	9%	6%	18%
Auto – 230kV	3%	3%	6%	18%	18%	12%	15%	9%	3%	15%
Auto – 345kV	3%	3%	6%	21%	12%	12%	15%	9%	3%	18%
Auto – 500kV	3%	3%	6%	18%	15%	12%	12%	9%	3%	21%

7

ASSESSMENT AND REPLACEMENT PRACTICES FOR TRANSFORMERS

Survey participants were asked a series of questions about their practices regarding assessment and replacement of transformers. Responses are presented in this chapter.

Replacement Categories

What percentage of your transmission transformers replacements fall into the following categories?

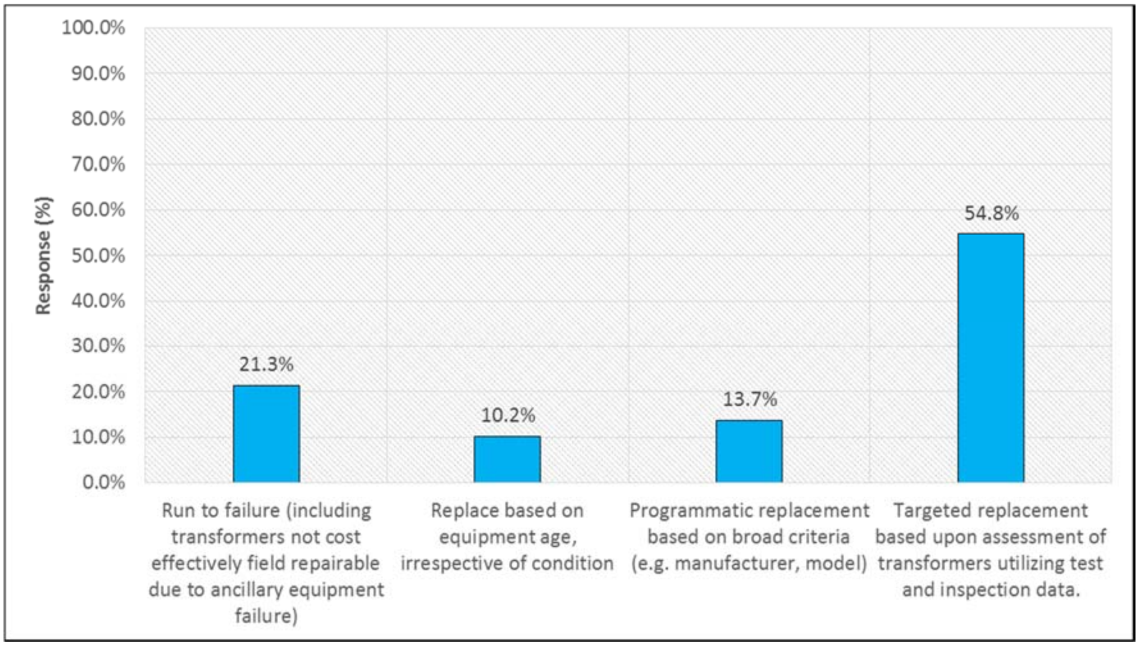

Figure 7-1
Replacement Categories

Replacement Planning and Budgeting

Question: *Do you plan/budget for a specific number of transmission transformer replacements per year?*

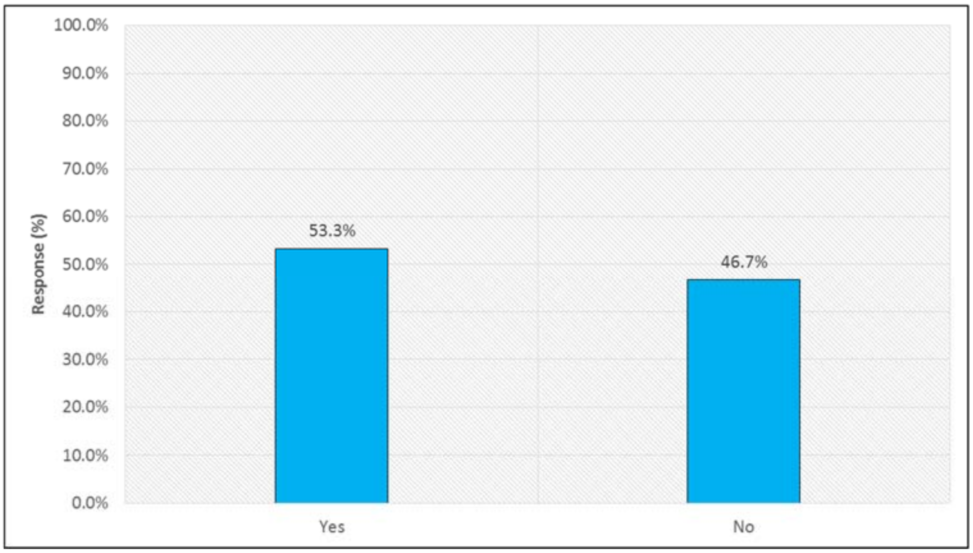

Figure 7-2
Do you plan/budget for a specific number of transmission transformer replacements per year?

Criteria for Annual Planned Replacements

Question: *What factors contribute to determine the number of planned replacements per year? (Please Rank 1-5 with 5 being most critical.)*

Table 7-1
Averages of Criteria Ranking for Determining Number of Planned Replacements per Year

Criteria	Ranking Average
Condition of individual assets	4.00
Budgetary constraints	3.18
Statistical analysis of failure rates applied to transformer population	3.00
Age distribution of transformers	2.94
Estimate based on past experience	2.50

Evaluating Replacement Rate

Question: *"How does your organization evaluate whether the future replacement rate (next 5 years) is adequate? (Select all that apply)"*

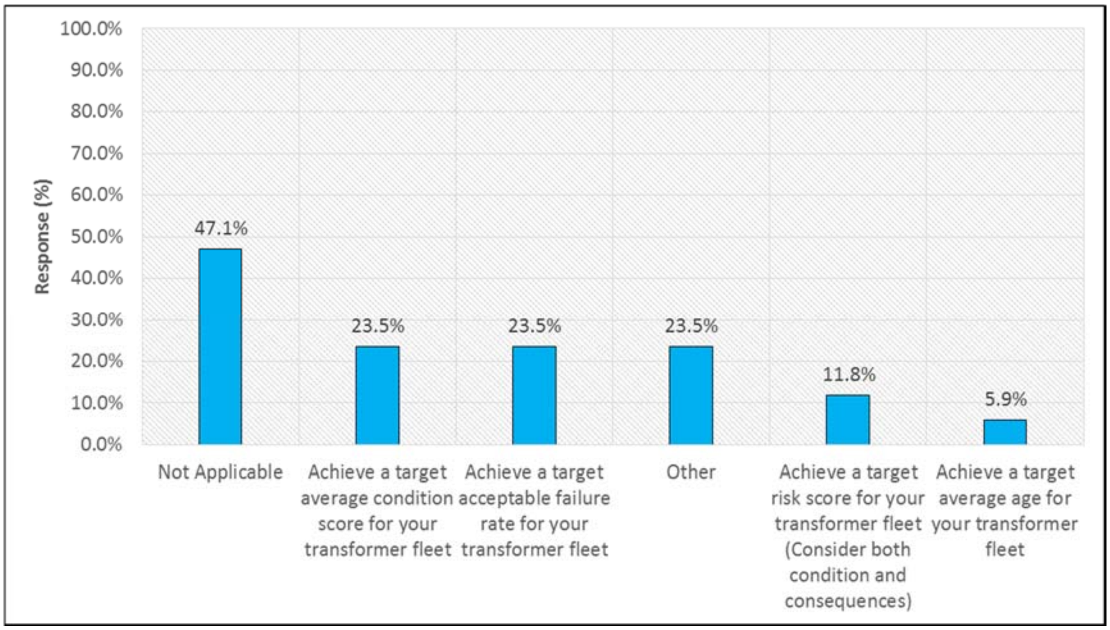

Figure 7-3
Evaluating Replacement Rate

Respondents who answered "Other" provided the following comments:

> "Moving to a targeted risk score in 2017."
>
> "Try to achieve a target average condition score for your transformer fleet. However, it's only a recommendation and does not necessarily feedback into the formal budgeting process."
>
> "We are currently developing justification to increase our proactively replaced transformers a by showing predictive indicators of failure rate and reliability."
>
> "Replacement rate is largely driven by Budgetary constraints."

Refurbishment to Extend Service Life

Question: *"Do you refurbish transformers to extend service life?"*

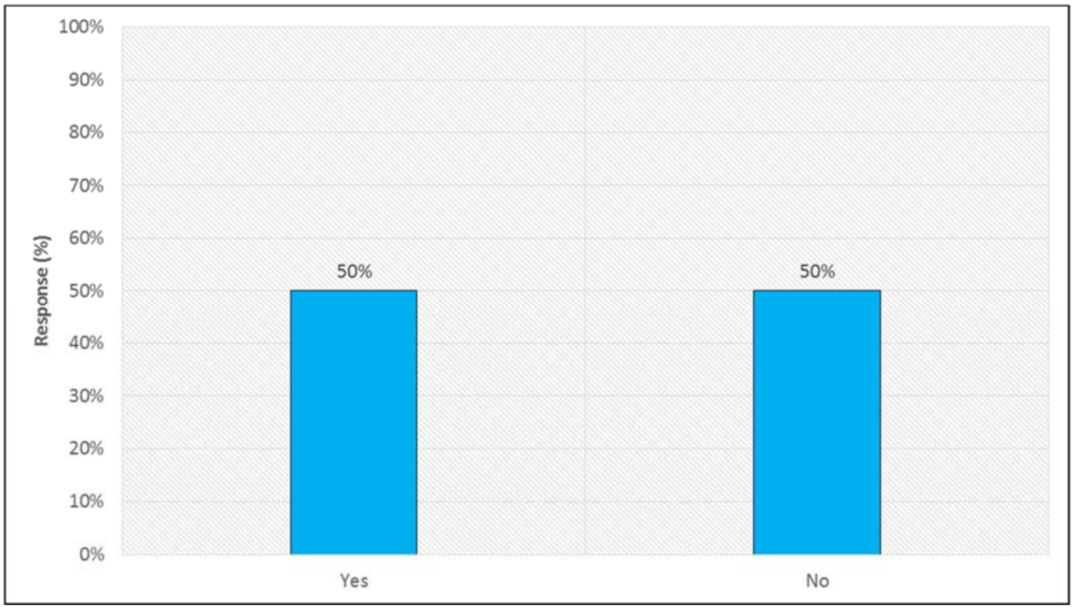

Figure 7-4
Refurbish to Extend Service Life?

Process or Algorithm to Assess Condition

Asked if they had a formal process or algorithm to assess transformer condition, respondents provided the answers shown in Figure 7-5.

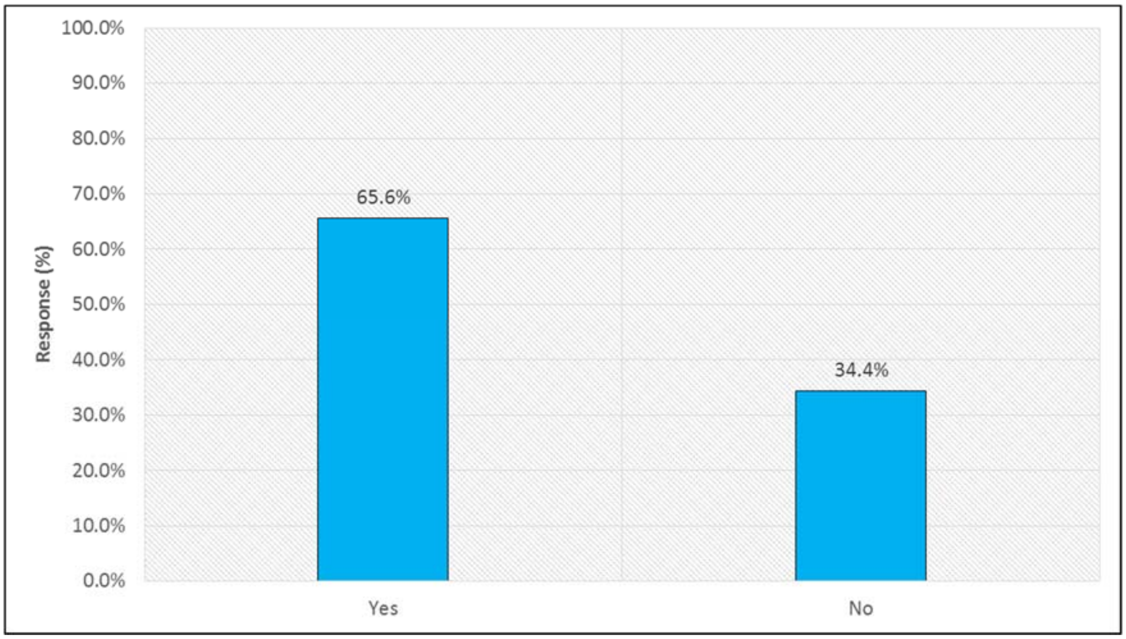

Figure 7-5
Do you have a formal process or algorithm to assess transmission transformer condition?

Respondents were asked to describe the process or algorithm. Their answers are shown in Figure7-6.

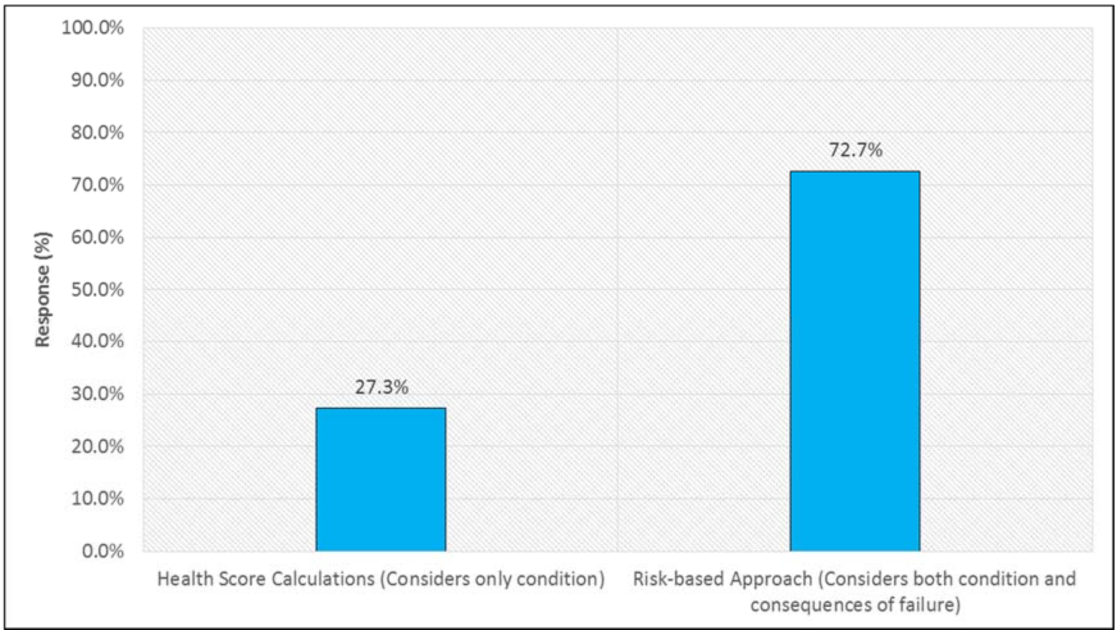

Figure 7-6
How would you best describe the formal process or algorithm?

Participants were asked to rank the input factors to this formal process or algorithm? (1-8 with 8 being most critical). Results are shown in Table 7-2.

Table 7-2
Ranking Input Averages to Formal Process or Algorithm

Criteria	Ranking Average
Condition	7.18
System Criticality	6.22
Health and Safety	5.00
Utilization	4.71
Design/Obsolesce/Maintainability	4.44
Performance (SAIDI,SAIFI,MAIFI)	4.00
Economical (Internal and/or External)	3.63
Demographics	3.55

Asked if their algorithm could trigger a replacement by itself, respondents provided answers shown in Figure 7-7.

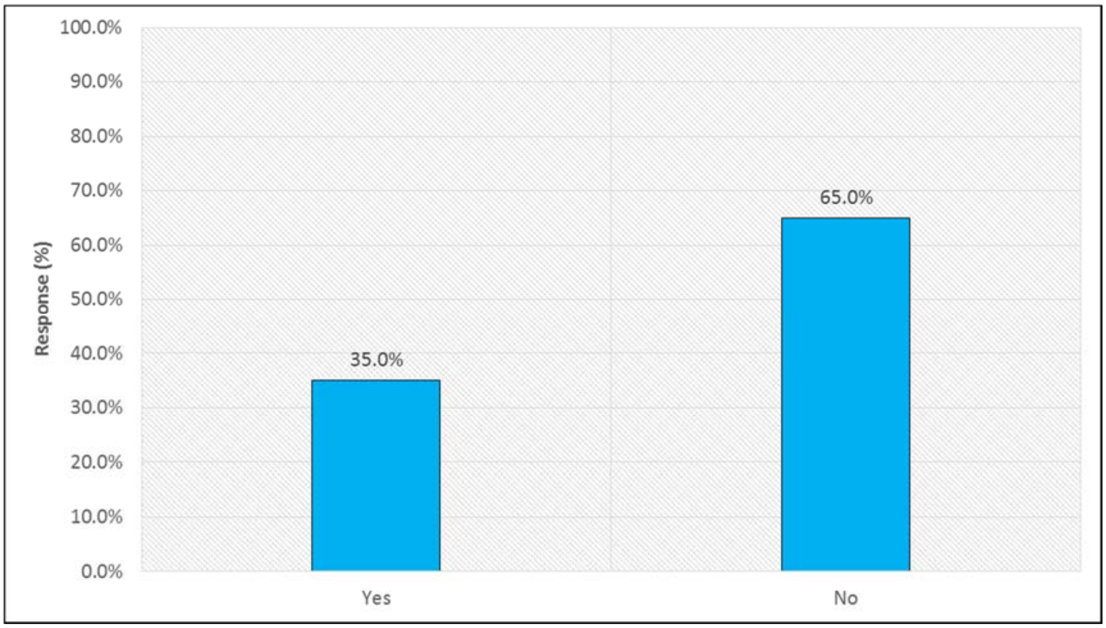

Figure 7-7
Could your algorithm trigger a replacement by itself?

Respondents answering "No" were asked a follow-up question: *What else is needed for your algorithm to trigger a replacement?* Responses follow:

> "Approval by SME."

> "Economic, criticality, redundancy factors etc."

> "Algorithm initiates an in-depth review of the asset and development of a mitigation strategy. The strategy may be other than replacement."

> "Simply another tool to make educated decisions. The final decision requires input asset management engineers."

> "Scoring reviewed and investment strategy is the developed."

> "Engineering review of all data."

> "Each of the condition factors that are inputs into the health index need to be manually assessed."

> "Evaluation by engineering and operations staff."

> "Formal process to use algorithm outputs in planning decisions with input from field personnel, equipment experts, customers and long term planning groups."

8
SUMMARY AND NEXT STEPS

Circuit Breaker Survey Summary

Respondent Characteristics

- Approximately 50% of respondents are Engineering Staff
- About 60% of member respondents' systems have a peak load equal to or greater than 10000 MW
- Around three quarters of respondents used some formal definition of End of Life

Age of Concern for Circuit Breakers

The following tables provide the approximate ages at which more than 50% of respondents would be concerned or very concerned about leaving the circuit breaker in service.

Oil Breakers

Answer Options	Concerned	Very Concerned
34 to < 69 kV (Oil)	49 Yrs	55 Yrs
69 kV (Oil)	50 Yrs	55 Yrs
115 kV (Oil)	47 Yrs	54 Yrs
230 kV (Oil)	46 Yrs	53 Yrs
345 kV (Oil)	46 Yrs	54 Yrs
500 kV (Oil)	46 Yrs	54 Yrs

Gas Breakers

Answer Options	Concerned	Very Concerned
34 to < 69 kV (Gas)	44 Yrs	53 Yrs
69 kV (Gas)	44 Yrs	53 Yrs
115 kV (Gas)	44 Yrs	53 Yrs
230 kV (Gas)	44 Yrs	52 Yrs
345 kV (Gas)	44 Yrs	52 Yrs
500 kV (Gas)	44 Yrs	52 Yrs

- 34 to 115 kV: Majority concerned 44 to 45 years. Majority <u>very</u> concerned 53 to 54 years
- 230 to 500 kV: Majority concerned 44 years. Majority <u>very</u> concerned 51 to 52 years

Vacuum Breakers

Answer Options	Concerned	Very Concerned
34 to < 69 kV (Vac)	45 Yrs	54 Yrs
69 kV (Vac)	44 Yrs	53 Yrs
115 kV (Vac)	44 Yrs	54 Yrs

Circuit Breaker Assessment and Replacement Practices

- Two-thirds of respondents do not run transmission circuit breakers to failure
- Condition and safety are the two highest ranked criteria for replacing a breaker
- Majority of utilities do not have a formal process or algorithm for assessing circuit breaker condition
- Most utilities that have a formal process or algorithm for assessing circuit breaker condition do not allow the algorithm to automatically trigger a replacement
- Majority of utilities do replace circuit breakers by type/family regardless of individual age or condition with decisions highly based on population condition, population ownership costs, population reliability, safety, and environmental impact.

Transformer Survey Summary

Respondent Characteristics

- Approximately 56% of respondents are Engineering Staff
- Almost 60% of member respondents' systems had a peak load equal to or greater than 10000 MW
- Around three-quarters of respondents used some formal definition of End of Life

Age of Concern for Transformers

The following tables provide the approximate ages at which more than 50% of respondents would be concerned or very concerned about leaving the transformer in service.

Answer Options	Concerned	Very Concerned
GSU	47 Yrs	54 Yrs
Conventional (>= 69 kv)	54 Yrs	60 Yrs
Auto – 230kV	50 Yrs	56 Yrs
Auto – 345kV	50 Yrs	57 Yrs
Auto – 500kV	50 Yrs	57 Yrs

- GSU, Conventional, Auto 230kV: Majority concerned 46 to 53 years. Majority <u>very</u> concerned 54 to 60 years
- Auto 345kV and Auto 500kV: Majority concerned 49 to 51 years. Majority <u>very</u> concerned 56 to 58 years

Transformer Assessment and Replacement Practices

- Most utilities target replacement based upon assessment of the asset using test and inspection data
- Just over 50% of utilities budget for a specified number of replacements per year with the highest weights on condition of individual asset and budgetary constraints
- Nearly half of utilities do not evaluate a 5 year replacement rate
- Half of utilities refurbish transformers to extend life
- Majority of utilities do have a formal process or algorithm for assessing transformer condition. Nearly three-fourths of utilities use a risk-based approach with condition and system criticality ranking highest for their algorithm inputs
- Most utilities that have a formal process or algorithm for assessing transformer condition do not allow the algorithm to automatically trigger a replacement

Next Steps

The results documented in this report provide additional data points in a series of EPRI utility surveys designed to acquire information and insights on industry attitudes and practices related to asset management of transmission circuit breakers and transformers. Survey results may help utilities to learn how peer companies are responding to similar challenges, and may also help inform and guide research and development efforts to further improve substation asset management practices.

A
SURVEY QUESTIONS: CIRCUIT BREAKERS

A web-based survey tool was used to construct a set of focused questions that could provide an assessment of current industry assessment and replacement practices for transmission circuit breakers and power transformers.

The circuit breaker survey questions are presented here in Appendix A. The transformer survey questions are presented in Appendix B.

Circuit Breaker Survey

About this Survey

EPRI has initiated this survey with the following goals/key objectives:

-Assess attitudes and practices related to circuit breaker replacement and asset management programs

- Understand how peer companies are responding to similar challenges

The responses that we gather through this survey will be summarized in a document in a non-attributable fashion.

In exchange for your help in completing the survey, EPRI will provide you with a summary of the results.

Should you desire to have multiple people from your company complete a copy of the survey (For example, people from different operating companies of a holding company), simply forward the link to the appropriate individuals and ask them to complete a survey.

On occasion, we ask for numbers of various populations or for specific information. While we would like the most accurate answers possible, we understand that some numbers would require some effort to collect. In these cases, best estimates would be appreciated.

I recognize that you will have to make an investment in time to gather the information required to answer the questions in this survey - thank you in advance! The more complete listing of practices we can gather, the better able we will be to produce a practices document that is truly valuable to the participants!

I am requesting your help in identifying practices in place at your company by completing this on line survey between now and May 19th, 2017.

Personal Details

1. Please enter the following contact information. Leave this blank if you prefer to remain anonymous.

Name

Company

Email Address

Phone Number

* 2. Your Job Classification

- Manager
- Engineering Staff
- Supervisor
- Other (please specify)

* 3. Your Organization

- Asset management group (if separate)
- Engineering
- Maintenance
- Other (please specify)

Company Information

* 4. Which of the following best describes your company?

- Investor Owned Utility (IOU)
- Generation and Transmission Utility (G&T)
- Municipal Utility (Muni)
- Power Cooperative (Coop)
- Power Marketing Administration (PMA)
- Federal Government

* 5. Regulatory Structure

- Regulated
- De-regulated
- Elements of both

* 6. Assets Owned

	None	Few	Secondary business	Primary business
Generation				
Transmission				
Distribution				

Survey-Part 1: System and Fleet Characteristics

7.What is your system peak load?

- ◯ 0 – 1000 MW
- ◯ 1001 – 10,000 MW
- ◯ 10,001 – 20,000 MW
- ◯ 20,001 – 30,000 MW
- ◯ > 30,000 MW

While we would like the most accurate answers possible, we understand that some numbers would require some effort to collect. In these cases, please provide best estimates for questions 8-11.

8.How many transmission circuit breakers (>= 34 kV) do you have in service that are**Live Tank SF6 Circuit Breakers**?

9. How many transmission circuit breakers (>= 34 kV) do you have in service that are**Dead Tank SF6 Circuit Breakers**?

10. How many transmission circuit breakers (>= 34 kV) do you have in service that are**Bulk Oil Circuit Breakers**?

11. How many transmission circuit breakers (>= 34 kV) do you have in service that are**Minimum Oil Circuit Breakers**?

Survey-Part 2: EOL Concerns

12. Utilities use different terms to define the end of life and expected service life of assets. For example, Hydro One uses the following definitions:

End of Life (EOL): The high likelihood of failure, or loss of an asset's ability to provide the intended functionality as determined through diagnostic data, wherein the failure or loss of functionality would cause unacceptable consequences. EOL can be further divided into three sub-categories:

- Technical EOL: The asset has failed, or condition assessment data indicates it is likely to do so, or it can no longer be expected to perform its function reliably
- Economic EOL: Unacceptable levels of maintenance costs are required to achieve the required performance/function.
- Strategic EOL: Necessary spares parts or skills set are unavailable; or the forecast loading or short circuit levels have exceeded the rating of the asset.

Expected Service life (ESL): The average time in years that an asset can be expected to operate under normal system conditions.

Does your company use these or similar definitions?

- ◯ Yes
- ◯ No (please specify)

* 13. Please indicate in the following table the age ranges at which you would **start getting concerned** about leaving the asset in service (ideally target for planned replacement in the next 5 to 10 years). Please provide comments as appropriate.

For **oil** circuit breaker voltage levels, at what age would you **start getting concerned**?

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Regardless of concern, will run to failure
34 to < 69 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
69 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
115 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
230 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
345 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
500 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯

Comments

* 14. Please indicate in the following table the age ranges at which you would **start getting concerned** about leaving the asset in service (ideally target for planned replacement in the next 5 to 10 years). Please provide comments as appropriate.

For **gas** circuit breaker voltage levels, at what age would you **start getting concerned**?

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Regardless of concern, will run to failure
34 to < 69 kV	○	○	○	○	○	○	○	○	○	○
69 kV	○	○	○	○	○	○	○	○	○	○
115 kV	○	○	○	○	○	○	○	○	○	○
230 kV	○	○	○	○	○	○	○	○	○	○
345 kV	○	○	○	○	○	○	○	○	○	○
500 kV	○	○	○	○	○	○	○	○	○	○

Comments

* 15. Please indicate in the following table the age ranges at which you would **start getting concerned** about leaving the asset in service (ideally target for planned replacement in the next 5 to 10 years). Please provide comments as appropriate.

For **vacuum** circuit breaker voltage levels, at what age would you **start getting concerned**?

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Regardless of concern, will run to failure
34 to < 69 kV	○	○	○	○	○	○	○	○	○	○
69 kV	○	○	○	○	○	○	○	○	○	○
115 kV	○	○	○	○	○	○	○	○	○	○

Comments

* 16. Please indicate in the following table the age ranges at which you would **start getting very concerned** about leaving the asset in service (ideally target for planned replacement in the next 2 to 5 years). Please provide comments as appropriate.

For **oil** circuit breaker voltage levels, at what age would you **start getting very concerned**?

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Regardless of concern, will run to failure
34 to < 69 kV	○	○	○	○	○	○	○	○	○	○
69 kV	○	○	○	○	○	○	○	○	○	○
115 kV	○	○	○	○	○	○	○	○	○	○
230 kV	○	○	○	○	○	○	○	○	○	○
345 kV	○	○	○	○	○	○	○	○	○	○
500 kV	○	○	○	○	○	○	○	○	○	○

Comments

* 17. Please indicate in the following table the age ranges at which you would **start getting <u>very</u> concerned** about leaving the asset in service (ideally target for planned replacement in the next 2 to 5 years). Please provide comments as appropriate.

For **gas** circuit breaker voltage levels, at what age would you **start getting very concerned**?

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Regardless of concern, will run to failure
34 to < 69 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
69 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
115 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
230 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
345 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
500 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯

Comments

* 18. Please indicate in the following table the age ranges at which you would **start getting <u>very</u> concerned** about leaving the asset in service (ideally target for planned replacement in the next 2 to 5 years). Please provide comments as appropriate.

For **vacuum** circuit breaker voltage levels, at what age would you **start getting very concerned**?

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Regardless of concern, will run to failure
34 to < 69 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
69 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
115 kV	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯

Comments

Survey-Part 3: Assessment and Replacement Practices

19. Does your company typically run a transmission circuit breaker to failure (i.e., it becomes inoperable and/or too impractical or expensive to restore to operation)?

- ◯ Yes
- ◯ No

Survey-Part 3: Assessment and Replacement Practices

* 20. Please rank each of the following criteria you use to replace an asset. (Rank 1-7 with 1 being most critical)

[ ]	Condition	☐ N/A
[ ]	Ownership Costs (Maintenance, unavailability of skills, availability of spares, etc.)	☐ N/A
[ ]	Age	☐ N/A
[ ]	Safety	☐ N/A
[ ]	Environmental Impact	☐ N/A
[ ]	Reliability/Availability	☐ N/A
[ ]	Asset Health Index/Trigger	☐ N/A

21. Please comment if there are any other criteria you use to replace an asset?

Survey-Part 3: Assessment and Replacement Practices

22. Do you have a formal process or algorithm to assess circuit breaker condition?

- ◯ Yes
- ◯ No

Survey-Part 3: Assessment and Replacement Practices

23. How would you best describe the formal process or algorithm?

◯ Health Score Calculations (Considers only condition)

◯ Risk-based Approach (Considers both condition and consequences of failure)

24. Could your algorithm trigger a replacement by itself?

◯ Yes

◯ No (Please comment on what else would be required)

Survey-Part 3: Assessment and Replacement Practices

25. Do you replace circuit breakers by type or family regardless of age or condition (e.g., OCBs, air-blast)?

- ◯ Yes
- ◯ No

Survey-Part 3: Assessment and Replacement Practices

26. Please provide a list of the types of families that you have replaced regardless of age or condition.

27. How do you decide when to replace a population (or fleet) of assets? (Programmatic replacement) (Select all that apply)

- [ ] Population Condition
- [ ] Population Ownership Costs (Maintenance, unavailability of skills, availability of spares, etc.)
- [ ] Average age
- [ ] Safety
- [ ] Environmental Impact
- [ ] Population Reliability
- [ ] Population Availability
- [ ] Achieve a levelized work plan to increase predictability of budgets and work load forecasts
- [ ] Increase efficiencies in contracting (master contracts, bulk purchases, etc.)
- [ ] Improve project execution through predictability (i.e., meet and deliver on scope/schedule/budget annually)
- [ ] Other (please specify)

Survey-Part 3: Assessment and Replacement Practices

28. Do you restrict your use of stand-alone breakers to air insulated substations?

◯ Yes

◯ No

29. When replacing a breaker, what other equipment is replaced? (Select all that apply)

☐ Switches

☐ Bay

☐ Bus

30. If you expand the scope of a replacement project, what are the drivers? (Select all that apply)

☐ Outage considerations

☐ Project logistics

☐ Project cost

☐ Aggregated risk

While we would like the most accurate answers possible, we understand that some numbers would require some effort to collect. In these cases, please provide best estimates for the following question.

31. What is the age breakdown of your circuit breaker fleet?

	None	0 to 10 %	10 to 20 %	20 to 30 %	30 to 40 %	40 to 50 %	50 to 60 %	60 to 70 %	70 to 80 %	80 to 90 %	90 to 100 %
< 10 years	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
10-20 years	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
20-30 years	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
30-40 years	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
40-50 years	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
>50 years	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯

Thank you for participating in this survey!

Upon completion of the survey, the results will be compiled in a summary report and results will be provided to members in a webcast.

B
SURVEY QUESTIONS: TRANSFORMERS

A web-based survey tool was used to construct a set of focused questions that could provide an assessment of current industry assessment and replacement practices for transmission circuit breakers and power transformers.

The transformer survey questions are presented here in Appendix B. The circuit breaker survey questions are presented in Appendix A.

Transformer Survey

About this Survey

EPRI has initiated this survey with the following goals/key objectives:

-Assess attitudes and practices related to transformer replacement and asset management programs

- Understand how peer companies are responding to similar challenges

The responses that we gather through this survey will be summarized in a document in a non-attributable fashion.

In exchange for your help in completing the survey, EPRI will provide you with a summary of the results.

Should you desire to have multiple people from your company complete a copy of the survey (For example, people from different operating companies of a holding company), simply forward the link to the appropriate individuals and ask them to complete a survey.

On occasion, we ask for numbers of various populations or for specific information. While we would like the most accurate answers possible, we understand that some numbers would require some effort to collect. In these cases, best estimates would be appreciated.

I recognize that you will have to make an investment in time to gather the information required to answer the questions in this survey - thank you in advance! The more complete listing of practices we can gather, the better able we will be to produce a practices document that is truly valuable to the participants!

I am requesting your help in identifying practices in place at your company by completing this on line survey between now and May 19th, 2017.

Personal Details

1. Please enter the following contact information. Leave this blank if you prefer to remain anonymous.

Name

Company

Email Address

Phone Number

* 2. Your Job Classification

- Manager
- Engineering Staff
- Supervisor
- Other (please specify)

* 3. What organization do you reside in?

- Asset Management group (if separate)
- Engineering
- Maintenance
- Other (please specify)

Company Info

4. Which of the following best describes your company?

- ◯ Investor Owned Utility (IOU)
- ◯ Generation and Transmission Utility (G&T)
- ◯ Municipal Utility (Muni)
- ◯ Power Cooperative (Coop)
- ◯ Power Marketing Administration (PMA)
- ◯ Federal Government

5. Regulatory Structure

- ◯ Regulated
- ◯ De-regulated
- ◯ Elements of both

* 6. Assets Owned

	None	Few	Secondary business	Primary business
Generation	◯	◯	◯	◯
Transmission	◯	◯	◯	◯
Distribution	◯	◯	◯	◯

Survey-Part 1: System and Fleet Characteristics

7. What is your system peak load?

- 0 – 1000 MW
- 1001 – 10,000 MW
- 10,001 – 20,000 MW
- 20,001 – 30,000 MW
- > 30,000 MW

<u>A transmission transformer in this survey is being defined as >= 69 kV.</u>

8. How many transmission transformers do you have in service?

* 9. What is the age breakdown of your transmission transformer fleet?

	10 to 20 %	20 to 30 %	30 to 40 %	40 to 50 %	50 to 60 %	60 to 70 %	70 to 80 %	0 to 10 %	80 to 90 %	90 to 100 %
< 10 years										
10-20 years										
20-30 years										
30-40 years										
40-50 years										
>50 years										

Survey-Part 2: EOL Concerns

10. Utilities use different terms to define the end of life and expected service life of assets. For example, Hydro One uses the following definitions:

End of Life (EOL): The high likelihood of failure, or loss of an asset's ability to provide the intended functionality as determined through diagnostic data, wherein the failure or loss of functionality would cause unacceptable consequences. EOL can be further divided into three sub-categories:

- Technical EOL: The asset has failed, or condition assessment data indicates it is likely to do so, or it can no longer be expected to perform its function reliably
- Economic EOL: Unacceptable levels of maintenance costs are required to achieve the required performance/function.
- Strategic EOL: Necessary spares parts or skills set are unavailable; or the forecast loading or short circuit levels have exceeded the rating of the asset.

Expected Service life (ESL): The average time in years that an asset can be expected to operate under normal system conditions.

Does your company use these or similar definitions? If not, what definition(s) do you use?

- ○ Yes
- ○ No
- ○ Other (please specify)

* 11. Please indicate in the following table the age ranges at which you would **start getting concerned** about leaving the following transmission transformer assets in service (ideally target for planned replacement in the next 5 to 10 years). Please provide comments as appropriate.

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Regardless of concern, will run to failure
Generator Step-up Unit (GSU)	○	○	○	○	○	○	○	○	○	○
Conventional Transformer (69 kv and Above)	○	○	○	○	○	○	○	○	○	○
Auto – 230kV	○	○	○	○	○	○	○	○	○	○
Auto – 345kV	○	○	○	○	○	○	○	○	○	○
Auto – 500kV	○	○	○	○	○	○	○	○	○	○

Comments

* 12. Please indicate in the following table the age ranges at which you would **start getting <u>very</u> concerned** about leaving the following transmission transformer assets in service (ideally target for planned replacement in the next 2 to 5 years). Please provide comments as appropriate.

	30-35 Years	35-40 Years	40-45 Years	45-50 Years	50-55 Years	55-60 Years	60-65 Years	65-70 Years	70-75 Years	Regardless of concern, will run to failure
Generator Step-up Unit (GSU)	○	○	○	○	○	○	○	○	○	○
Conventional Transformer (69 kv and Above)	○	○	○	○	○	○	○	○	○	○
Auto – 230kV	○	○	○	○	○	○	○	○	○	○
Auto – 345kV	○	○	○	○	○	○	○	○	○	○
Auto – 500kV	○	○	○	○	○	○	○	○	○	○

Comments

Survey-Part 3: Assessment and Replacement Practices

* 13. What percentage of your transmission transformers replacements fall into the following categories?

	None	0 to 10 %	10 to 20 %	20 to 30 %	30 to 40 %	40 to 50 %	50 to 60 %	60 to 70 %	70 to 80 %	80 to 90 %	90 to 100 %
Run to failure (including transformers not cost effectively field repairable due to ancillary equipment failure)	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
Replace based on equipment age, irrespective of condition	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
Programmatic replacement based on broad criteria (e.g. manufacturer, model)	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯
Targeted replacement based upon assessment of transformers utilizing test and inspection data.	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯	◯

14. Do you plan/budget for a specific number of transmission transformer replacements per year?

◯ Yes

◯ No

Survey-Part 3: Assessment and Replacement Practices

15. What factors contribute to determine the number of planned replacements per year? (Please Rank 1-5 with 1 being most critical)

- [ ] Age distribution of transformers ☐ N/A
- [ ] Estimate based on past experience ☐ N/A
- [ ] Statistical analysis of failure rates applied to transformer population ☐ N/A
- [ ] Condition of individual assets ☐ N/A
- [ ] Budgetary constraints ☐ N/A

16. How does your organization evaluate if the future replacement rate (next 5 years) is adequate? (How do you know if you are replacing enough, too many, or too few)

- [ ] Achieve a target average age for your transformer fleet
- [ ] Achieve a target average condition score for your transformer fleet
- [ ] Achieve a target risk score for your transformer fleet (Consider both condition and consequences)
- [ ] Achieve a target acceptable failure rate for your transformer fleet
- [ ] Not Applicable
- [ ] Other (please specify)

Survey-Part 3: Assessment and Replacement Practices

17. Do you refurbish transformers to extend service life?

- ◯ Yes
- ◯ No

18. Do you have a formal process or algorithm to assess transmission transformer condition?

- ◯ Yes
- ◯ No

Survey-Part 3: Assessment and Replacement Practices

19. How would you describe the formal process or algorithm?

☐ Health Score Calculations (Considers only condition)

☐ Risk-based Approach (Considers both condition and consequences of failure)

20. Please rank the input factors to this formal process or algorithm? (Please rank 1-8 with 1 being most critical)

Rank	Factor	N/A
	Demographics	☐ N/A
	Condition	☐ N/A
	Utilization	☐ N/A
	Performance (SAIDI,SAIFI,MAIFI)	☐ N/A
	Economical (Internal and/or External)	☐ N/A
	System Criticality	☐ N/A
	Design/Obsolesce/Maintainability	☐ N/A
	Health and Safety	☐ N/A

21. Could your algorithm trigger a replacement by itself?

○ Yes

○ No (Please comment on what else would be required)

Thank you for participating in this survey!

Upon completion of the survey, the results will be compiled in a summary report and results will be provided to members in a webcast.

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EXPECTED SERVICE LIFE (ESL) ASSESSMENT OF SPECIFIC UNDERGROUND TRANSMISSION CABLES

DECEMBER 2017

EPRI Project Manager
T. Zhao
tzhao@epri.com, 1-704-595-2532

Hydro One Project Manager
T. Wales

Principal Investigators

J. Williams, Power Delivery Consultants
T. Zhao, EPRI

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SUMMARY AND RECOMMENDATIONS

Hydro One provided a great deal of historical data on its high-pressure liquid-filled (HPLF) pipe-type cable circuits and its low-pressure liquid-filled (LPLF) self-contained cable circuits. Review of that information, calculation of critical parameters such as degree of thermal aging of the insulation, and evaluation of experience of other users of these cable types, permitted making conservative estimates of the design end of service life (expected service life – ESL) for both HPLF and LPLF cables.

High-pressure Liquid-filled Cables

Circuit loading has been significantly lower than the cable ratings. As a result, the thermal aging of the cable insulation is minimum. If an extremely conservative average operating temperature of 65°C is used for determining the degree of aging, the oldest HPLF cable has used only ten years of the presently assumed 50 year life. If the cables are loaded to their full rating in future operations, they should have another 40 years of life. Although analysis of loading data indicates that this is a conservative number, we recommend that Hydro One assign an additional 20 years to the design life, to give a 70-year design life. Hydro One should repeat the analysis described in this report as the oldest circuits approach the 70-yr age.

No leaks have been reported on the cable pipes, indicating that the corrosion coating and cathodic protection system are working well and will not limit the service life of the cable system. No unusual difficulties are reported on the corrosion protection system, splices, terminations, or dielectric liquid. With proper maintenance, these components will not limit the 70-year design life as recommended.

We recommend that Hydro One establish a 70-year period for the design end of service life for its HPLF cables, and that the cable condition be reviewed five years before that time. Hydro One should continue its maintenance testing such as dissolved gas analysis, fluid moisture content, and effectiveness of corrosion protection systems for buried steel pipes and manhole pipe sections. If any test results indicate potential problems, Hydro One should investigate the cause and take corrective action.

Low-pressure Liquid-filled Cables

Loading on the LPLF circuits has also been much lower than design ratings, and the life of the cable insulation should exceed 70 years, as is the case for the HPLF cables.

However, leaks on several of the circuits and difficulties with the pressurizing system, indicate that Hydro One should consider replacing these circuits within the next ten to twenty years.

We recommend that Hydro One establish a 70-year period for the design end of service life for its LPLF cables, and that the cable condition be reviewed five years before that time. Hydro One should continue its maintenance testing such as dissolved gas analysis, fluid moisture content, and jacket integrity tests. If any test results indicate potential problems, Hydro One should investigate the cause and take corrective action. Hydro One should carefully monitor the condition of the lead sheaths and the liquid reservoirs, and should begin designing the *replacement of LPLF cables with modern generation XLPE cables and replace the LPLF cables within ten to twenty years.*

1
INTRODUCTION

Underground transmission cables have a minimum design life expectancy (expected service life – ESL) based upon cable type and installation/operating conditions. Many of the paper-insulated, laminar-dielectric cables in North America have reached this threshold and beyond. There are common concerns with respect to cable system condition and potential remaining life. Previous EPRI studies [1] identified key indicators for condition evaluation of cellulose paper-based cable insulation. The indicators utilize cable operating history and non-intrusive and/or intrusive measurements.

Hydro One has requested EPRI assistance in evaluating the expected service life of 115-kV and 230-kV paper-insulated, laminar-dielectric cables, both high-pressure fluid-filled and low-pressure fluid filled, on the Hydro One transmission system.

The total length of in-service underground transmission laminar dielectric cables installed in Hydro One is about 167 miles (270 km). The average age of the cable fleet is now over 36 years with almost one-quarter of the lines exceeding the design end of service life (ESL) of 50 years based on original design expectancy. Many of the cable circuits in service that have exceeded the 50-year ESL are considered in good condition and operated safely and reliably. A sound technical basis is needed to more accurately identify the ESLs of low-pressure and high-pressure fluid-filled cable circuits.

This report describes the analyses performed and provides results and recommendations for an expected service life for properly maintained paper-insulated cables. The report focuses on the cables themselves but includes brief discussions on major accessories. Accessories can generally be maintained and upgraded as necessary but there can be situations where the maintenance of accessories becomes sufficiently costly to justify replacement of the cable system.

Note that the analysis in this report is based upon maintenance records and other information provided.

Review of information provided by Hydro One showed that the utility has implemented very thorough maintenance practices and reporting, and this has contributed to the overall excellent condition and longevity of the cable systems.

2

BRIEF DESCRIPTION OF CABLE TYPES AND THE HYDRO ONE UNDERGROUND TRANSMISSION SYSTEM

Tabulations from Hydro One show that the underground transmission system includes 65 high-pressure liquid-filled (HPLF) cables, totaling 106 circuit-miles (171 circuit-km), and 45 low-pressure liquid-filled (LPLF) circuits, totaling 41 circuit-miles (66 circuit-km). Hydro One also has 12 cross-linked polyethylene (XLPE) cable circuits totaling 19 circuit-miles (31 circuit-km). General descriptions of HPLF and LPLF cable circuits are given below.

2.1 High-pressure Liquid-filled Cable Circuits

2.1.1 Description of Cable System

Pipe-type cable systems have the three cables (A, B, and C phase) insulated with tapes of kraft paper (or laminated paper-polypropylene in more recent installations), installed in a common steel pipe. The pipe is pressurized, usually with a dielectric liquid. The system is called a high-pressure liquid-filled (HPLF) or high-pressure fluid-filled (HPFF) cable system. This cable system was called high-pressure oil-filled (HPOF) until the 1970s when synthetic dielectric liquids began to replace the mineral oils that had been used earlier.

North America is the major user of pipe-type cables, with the earliest installation in the 1930s and significant installations at 345 kV beginning in the early 1960s. There also are installations in Ireland, Europe, and the Middle East. Japan has a few pipe-type installations.

Pipe-type cables have been the most commonly used transmission cable type in North America through the early twenty-first century for several major reasons:

- The pipe provides rugged protection against third-party damage.
- The system is reliable.
- The pipe can be installed in relatively short street openings, minimizing traffic disruption in crowded urban areas, and it can generally be installed more quickly than a concrete-encased duct bank.
- The dielectric liquid provides several options for cooling to improve the circuit rating.

The three phases making up a line are pulled together into a previously installed coated and cathodically protected steel pipe, with distances commonly 1500-3000 ft (490-980 m) between splices. Older systems typically have shorter spacings; improvements in cable installation methods have permitted longer lengths for newer systems. After the entire line is installed, including splices and terminations, and the pipe welding is completed, the line is evacuated, then filled with a dielectric liquid (or possibly nitrogen gas for lines up through 138 kV). The liquid is pressurized to a nominal 200 psig (1380 kPa) using a pressurizing plant that also has a reservoir tank to accept volume changes due to system thermal expansion and contraction, as well as pumps, controls, and alarm systems.

There have been about 3725 circuit-miles (5995 circuit-km) of HPLF cables placed in service in North America since the 1930s.

Figure 2.1 shows a HPLF cable cross-section.

Figure 2.1
Cross-section of HPLF cable

2.1.2 HPLF Cables on Hydro One System

The majority of the cables are 1250-kcmil (600 mm^2) copper-conductor cables in nominal 6-in. and 8-in (16.8-cm and 21.9-cm) pipes. Other conductor sizes are 1000 kcmil, 1500 kcmil, 1750 kcmil, 2250 kcmil, and 2500 kcmil (500, 750, 875, 1125, and 1250 mm^2). Both 115-kV and 230-kV cables are installed. Most of the cables were provided by Canada Wire and Pirelli/Prysmian, neither of which produces pipe-type cables today. In-service dates range from 1961 (56 years) to 2004 (13 years). All circuits are lightly loaded. There have been no records of fluid leaks on the HPLF pipes.

Figure 2.2 shows the age distribution, taken from spreadsheets provided by Hydro One. The majority of the circuits have been in service for 36 to 45 years.

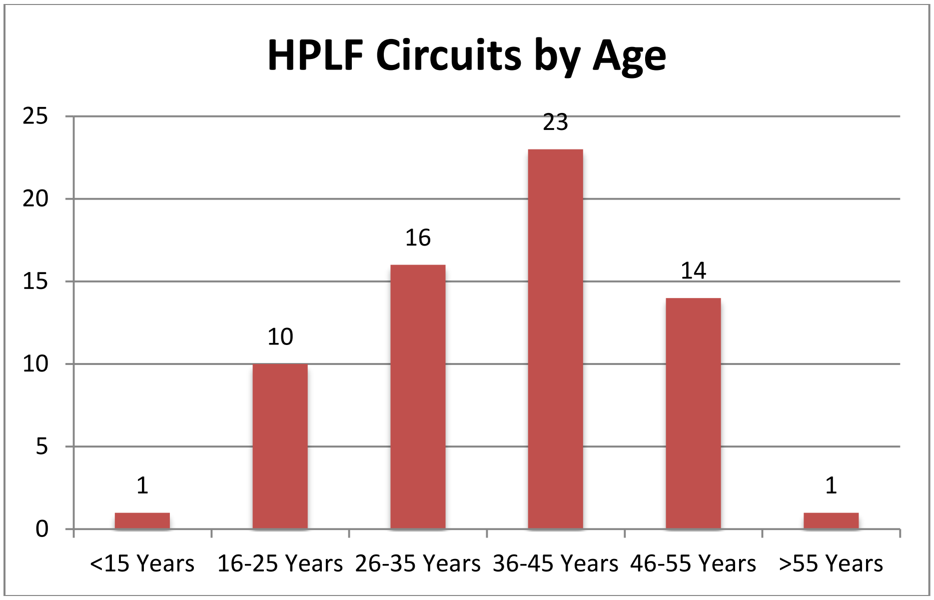


Figure 2.2
Age distribution, Hydro One HPLF circuits

The lengths of the HPLF circuits are fairly short, as shown in Figure 2.3. Most of the circuits are from one to three kilometers long.

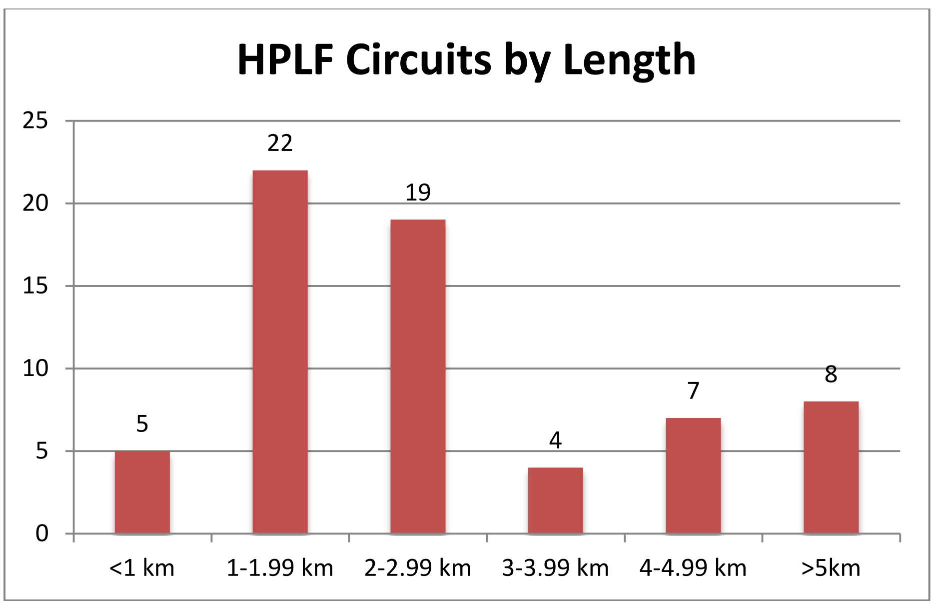


Figure 2.3
Length distribution, Hydro One HPLF circuits

2.2 Low-pressure Liquid Filled Cable Circuits

2.2.1 Description of Cable System

The first transmission cables used in North America were self-contained fluid-filled in the mid-1920s in Chicago and New York. The self-contained cable is insulated with paper (or laminated paper-polypropylene on newer lines) tapes and internally pressurized with a dielectric liquid, also named self-contained liquid-filled (SCLF) or self-contained fluid-filled (SCFF) cables in North America. This cable type was called low-pressure oil- filled (LPOF) until the 1970s when synthetic dielectric liquids began to replace the mineral oils that had been used earlier. Early cables were generally pressurized to 5-15 psig (35-105 kPa) while newer designs with aluminum or reinforced lead-alloy sheaths commonly operate at 5-75 psig (35-525 kPa). Small liquid reservoirs are placed along the route to maintain fluid pressure and accommodate fluid expansion and contraction with load changes. The presence of the dielectric liquid and reservoirs and the complexity of sheath bonding, are some of the disadvantages of the SCFF cable system.

They have been the principal cable type for EHV installations outside North America, with conductor sizes up to 6000 kcmil (3000 mm^2), carrying the highest power levels for a cable in the world. However, extruded-dielectric cables are now beginning to displace them worldwide.

The self-contained cable system consists of three individual phases, each contained within a hermetically sealed metallic sheath that is typically extruded lead-alloy or aluminum. The cables are insulated with a high-quality taped insulation. The fluid pressure necessary to prevent ionization is maintained through a hollow core in the center of the conductor. Figure 2-4 shows an SCFF cable.

There are about 1250 circuit-miles (2010 circuit-km) of LPLF cables in North America, in service since the 1920s.

Figure 2.4
Cross-section of LPLF cable

2.2.2 *LPLF Cables on the Hydro One System*

The majority of the cables are 1250-kcmil (600 mm^2) copper-conductor cables. Other conductor sizes are 1000 kcmil, 1145 kcmil, 1750 kcmil, and 2750 kcmil (500, 575, 875, and 1375 mm^2). Both 115-kV and 230-kV cables are installed. In-service dates range from 1955 (62 years) to 1992 (25 years). All circuits are lightly loaded. There have been many leaks on the LPLF cables.

Figure 2.5 shows the age distribution, taken from spreadsheets provided by Hydro One. The majority of the circuits have been in service for more than 45 years.

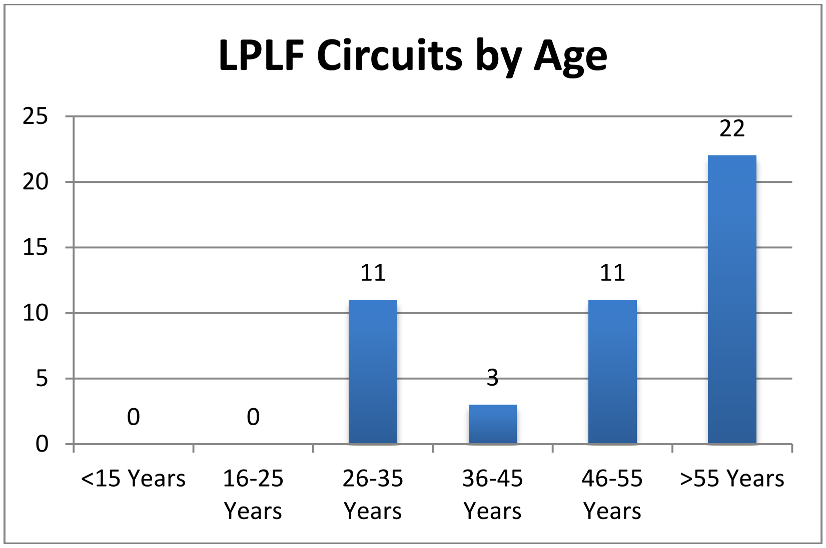


Figure 2.5
Age distribution, Hydro One LPLF circuits

Figure 2.6 shows length distribution. Most of the circuits are less than 2-km length.

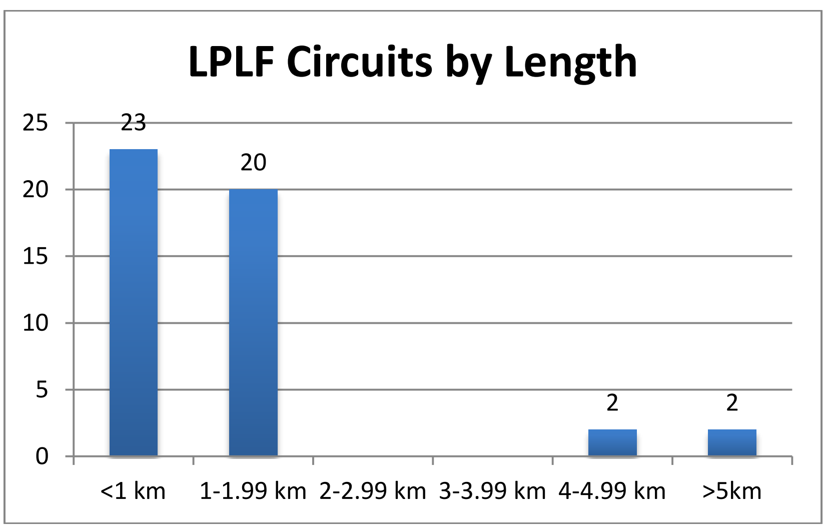


Figure 2.6
Length distribution, Hydro One LPLF circuits

3
CONSIDERATIONS FOR END-OF-LIFE OF HPLF AND LPLF CABLES

Impregnated-paper insulation can operate without incident for very long time if the following four criteria are met:

- The cables are operated within their design temperature ratings
- Required liquid pressures are maintained
- Moisture is not allowed to enter the system
- There is no mechanical damage

In addition to circuit loading history, operations of pressurizing systems, and cable and accessory mechanical constraints, the criteria mostly depend upon the integrity of the pipe for pipe-type cables, and depend upon the integrity of the sheath for self-contained fluid-filled cables. The provided Hydro One records showed limited fluid leaks as caused by pipe corrosion and jacket deteriorations, which indicated that the pipe or sheath/jacket of the Hydro One systems were well maintained. In addition, because these records are considered as isolated events on the Hydro One systems, the pipe corrosion and jacket deterioration can be treated as maintainable items and are not included in the following discussions.

The four criteria also depend upon the system operators utilizing the cable system within its design parameters and that circuit ratings take into account changes along the alignment, such as a distribution duct bank installed adjacent to the transmission cable. The general principles and comments on Hydro One cables are described in this section of the report, along with comments on industry trends for both cable types.

3.1 High-pressure Liquid-filled Cables

HPLF cables have generally had an excellent operating history. Comments on the four criteria that affect end-of-life are given below. Additional comments are given on leaks and cable availability.

3.1.1 Thermal Aging

Aging of the paper insulation as a function of operating temperature is well defined, and follows the Arrhenius aging relationship developed in the 1920s for transformer papers, and verified many times over the years for paper-insulated cables. Aging of the paper dielectric occurs following an 8-10 degree rule: for every 8 to 10 degrees increase in operating temperature, the cable aging rate is doubled. Failure is seldom measured by the electrical strength of the paper itself; it is measured by temperature-related mechanical changes to the paper. EPRI conducted an extensive program in the 1990s that performed accelerated aging tests on HPLF cables. The tests combined thermal and mechanical effects, and verified the Arrhenius aging [1]. As a simplification of the findings: the testing indicated that the aging rate doubles for every 9 Celsius degree increase in operating temperature. Therefore, a cable designed for a 50-year life at an

80°C temperature will lose two years of life if it is operated at 89°C for one year. Appendix A provides a brief summary of the thermal aging of a paper-insulated cable.

It is also true that the aging rate decreases for reductions in operating temperature. For example, a cable that would have an estimated service life of 50 years at design temperature of 80°C, would have an estimated service life of 100 years if operated at 71°C continuously, and 200 years if operated at 62°C continuously.

Although not verified by tests, the general industry feeling is that this relationship is valid over the range 60°C to 120°C.

Industry experience verifies this finding. Because of conservatism in design, provisions for future load growth, or redundancy for reliability purposes, almost all transmission cables operate well below their design temperatures, and consequently failures due to age are extremely uncommon. As further verification, there have been a few failures due to "thermal runaway" where the cables reached high temperatures due to localized conditions such as nearby trees pulling moisture from soil, resulting in high soil thermal resistivity and high cable temperatures. Those failed sections were repaired, the thermal bottleneck mitigated, and the line returned to service. Cable papers near the failure showed definite thermal aging, while papers from sections of the cable not subjected to high temperatures were still in excellent condition.

Since the rate of thermal aging is a function of cable loading, ideally an analysis would look at the average load every day of the year and calculate the degree of aging for that day (using the Arrhenius relationship described above) and sum the results for the year. This is ungainly; typically an analysis is performed for longer periods at average loading levels, e.g. first ten years of service at 50 percent of rated load, second ten years at 60 percent, etc. Since historical loading data are seldom available for older circuits, gross approximations are made. For the Hydro One study, we chose the conservative approach to say that historical loading was approximately equal to the values of loading provided by Hydro One for the three-year period January 1, 2014, to December 31, 2016.

Because of the low historical loadings on the Hydro One cables, we do not think that aging of the paper insulation will be the parameter that determines end of service life. This is discussed in detail in Chapter 4.

3.1.2 Maintaining Liquid Pressure

The electrical strength of impregnated paper insulation is maintained by pressurizing the cable system to eliminate voids and reduce ionization. HPLF cables are designed to have a nominal 200 psig (1380 kPa) pressure at the highest elevation of the circuit, and can operated for some time at pressures as low as 100 psig (690 kPa). LPLF cables operate at a much lower pressure, 15-45 psig (103-310 kPa). This is possible because the liquid is treated to remove contaminates and it is degassed.

We have no indications of pressure loss on Hydro One's HPLF and LPLF cable systems.

3.1.3 Moisture in Cable Systems

Moisture that enters the cable system is absorbed by the cable paper, creating an increase in dissipation factor. This increase results in higher electrical losses that can cause the insulation to overheat and create electrical failure.

In several cases, U.S. utilities have had to replace several manhole-to-manhole sections of HPLF cable because of water intrusion. Water pipes installed close to the cable pipes have had leaks, possibly caused by the cathodic protection system of the cable pipe. Water from the leak has jetted through the pipe coating, through the steel pipe, and into the dielectric liquid. Although cable damage can be widespread, the line can be restored to service after repairing the leak, cleaning the pipe, and replacing the cable.

Moisture can enter in other ways: moisture in the dielectric liquid (especially if it is provided in drums), improper construction operations, and loss of nitrogen atmosphere over the liquid in a pressurizing plant, etc.

We have no indications of moisture intrusion into the cable insulation for the Hydro One systems. Review of data provided by Hydro One shows very low moisture contents in all but a few isolated cases.

3.1.4 Mechanical Problems

HPLF cable circuits in the United States have had failures due to mechanical causes, identified as thermo-mechanical bending or thermo-mechanical movement. EPRI has conducted several studies of these failure mechanisms [2].

Thermo-mechanical Bending (TMB)

Thermo-mechanical bending itself is inevitable - cables subjected to load cycling move almost continually within the cable pipe due to thermal expansion and contraction with changing loads. The multiple layers of cable tapes slide on each other to accept the bending that occurs as the cables ‘snake’ within the pipe. A vast majority of the time, the cables accept many decades of this movement without incident – the cable tapes uniformly return to their original location. However, on occasion the cable tapes ratchet away from a location (typically observed to be the outside of a bend), leaving an area known as a “soft spot.” In some cases these soft spots are only in the outside layers of the cable and do not cause problems. In a few other cases, however, the soft spots progress toward the conductor to a point where electrical strength of the insulation is reduced sufficiently to cause electrical failure. This failure mechanism has been termed thermo-mechanical bending (TMB) failure. Cable construction strongly affects the tendency to form soft spots – and some constructions have been shown to be more vulnerable than others. However, field conditions (clearance within the pipe, dips and bends, degree of load changes, etc.) and possible damage during cable installation can also affect the tendency to form soft spots.

Thermo-mechanical Movement (TMM)

Thermo-mechanical movement has caused many failures, probably a greater number than TMB. TMM refers to cable movement that creates distress in the cable, typically by damaging the outer shielding which gives stress concentration and eventual failure. A typical TMM incident involves cables sliding downhill in a splice casing until the three cables wedge into the reducer at the downhill end of a joint, although this can happen in the uphill direction depending upon the cable route profile. The shielding tapes then separated, torn or badly indented, any of which lead to high electrical stresses. Other known incidents of TMM include skid wires indented into the cable at the uphill end of a sharp bend and displacement of termination stress cones by the weight of cable. Traffic-induced movement can also cause cables to migrate to one end of a splice, jamming the cables into the reducer and creating shielding tape damage.

One major U.S. utility recently replaced many HPLF cable circuits totaling more than 100 kilometers, principally because of TMB and TMM. The utility had experienced many TMB and TMM cable failures on different circuits. The utility conducted a detailed analysis of all of its HPLF cable circuits. This analysis included reviewing plan and profile drawings, evaluating historical loading, taking dissolved gas analysis samples, and X-raying all joints where movement was suspected. In many cases, the joints had migrated to one end of the casing, and wedged into the reducer. It is important to note, however, that the utility also required additional power transfer into the metropolitan area, so the utility was able to justify the installation of a larger-conductor cable with a lower loss laminated paper polypropylene cable.

External Damage

There have been many instances of cable failure due to dig-ins, but these have been random and the system can be returned to service after repairs.

3.1.5 Leaks

Pipe corrosion and resulting leaks of dielectric liquid are usually localized, for example initiated by corrosion coating damage from third-party excavation. These leaks are repaired, corrosion coating restored, and the incident does not affect life of the pipe/cable system. In a few instances corrosion has been widespread to the extent the utility has abandoned the HPLF line, and in one case the utility installed an XLPE-insulated cable (which requires no pressurization) into the pipe.

The majority of the Hydro One cable pipes are coated with coal-tar enamel and coal-tar fiberglass. Coal-tar enamel coatings (with or without fiberglass reinforcement) were extensively used in the 1940s through the 1970s on various pipe-type cable systems as well as on gas distribution and transmission systems. These coatings have performed well and have generally provided good dielectric isolation between the pipe and the soil that surrounds it.

Coal-tar coatings sometimes disbond and allow water to penetrate and contact the pipe surface. In most cases, this happens either because of poor construction practices or because the coating was poorly applied in the first place. If stray currents are present they can exacerbate the situation. Disbonded coating is worse than missing coating because while allowing moisture to reach the surface of the pipe it prevents some, if not all, cathodic protection currents from reaching these same areas, resulting in corrosion. Unfortunately there are no test methods that can find these areas, therefore they are often “discovered” only when leaks occur.

Material provided by Hydro One has not shown corrosion leaks on the HPLF cables or problems related to the corrosion coating or cathodic protection system, so end of service life should not be affected by pipe corrosion. However, for future operations and maintenance of the HPLF cable systems, evaluation of the integrity of the buried pipes can be a focus due to possible deterioration of the pipe coatings and changes of pipe installation environments. The evaluation includes ensuring effectiveness of cathodic protection and aboveground surveys to verify coating conditions.

3.1.6 Cable Availability

It should be noted that there is a concern among utilities that the sole remaining supplier of HPLF cables, The Okonite Company, in Paterson, New Jersey, USA, may discontinue producing the cables in the near future. This will have a strong negative effect on the long-term operation of HPLF cables; if Hydro One does not have sufficient spare cable, repair of a cable failure could require one or more HPLF to XLPE transition joints. The installation of transition joints is a costly, time-consuming procedure that may interrupt the fluid pressurization to sections of remaining HPLF cable.

3.2 Low-pressure Liquid-filled Cables

LPLF cables have also generally had an excellent operating history. Comments on criteria that affect end-of-life are given below, including thermal aging, lead sheaths, maintaining liquid pressure, stop joint failure, moisture in insulation, mechanical problems, leaks, sheath bonding systems, and cable availability.

3.2.1 Thermal Aging

The electrical performance of LPLF insulation has also been excellent. The Arrhenius aging relationship applies to LPLF cables just as it does to HPLF cables. The greater heat flux at the cable or duct interface with native soil, versus a HPLF cable, makes LPLF cables more vulnerable to overheating and thermal runaway, especially if special backfills are not used. The smaller mass of individual cables also causes the cables to heat more quickly during emergency loading periods.

Based upon information received from Hydro One, we do not think that aging of the paper insulation will be a concern because of the low historical loadings on the Hydro One cables. This is discussed in detail in Chapter 5.

LPLF cables do have other mechanisms that may lead to an earlier end of service life, described in the following paragraphs.

3.2.2 Lead Sheaths

Lead sheaths, and sheath wipes at joints and terminations, can crack and permit fluid leaks. This is especially true for sheaths that do not use fatigue-resistant lead and is especially true if cable joints are permitted to move in manholes.

Sheath corrosion can also create leaks, especially for early, unjacketed cables. Water can enter the LPLF cable if there are cracks in the cable sheath due to lead fatigue. Note that moisture can enter even if the cable liquid pressure is greater than the hydrostatic pressure of water because of differences in partial pressures.

At least one U.S. utility has replaced LPLF cables because of problems with leaks and with maintaining reservoirs. Programs have been conducted to develop XLPE-insulated cables that can be pulled into the LPLF ducts that are typically smaller diameter than used today [3].

U.S. utilities are concerned about the lack of skilled splicers that can make lead wipes but we understand that one or more Canadian firms, as well as those in the U.K., have the required expertise. New LPLF cables are seldom installed elsewhere in the world except for long submarine lines. XLPE-insulated cables are replacing the LPLF cables.

3.2.3 Maintaining Liquid Pressure

LPLF cables do not typically have a pressurizing plant such as those on pipe-type cables; they have liquid reservoirs installed at terminal ends and every few kilometers along the cable route. These reservoirs can create many problems if not properly maintained. Liquid in the reservoirs can sludge over time, reducing the ability of the reservoirs to supply the pressure needed to maintain dielectric strength of the insulated cable system. Alarm systems and signal wires can fail and the system can be unprotected against low pressures. Hydro One has had at least one failure due to liquid starvation, and this is an ongoing problem for U.S. utilities that still have LPLF cables in service; a major user of LPLF cables on the U.S. west coast has had many failures because of problems with liquid supply from the reservoirs and has a program to replace LPLF cables with XLPE-insulated cables, replacing one or two circuits per year.

3.2.4 Stop Joint Failure

There have been many electrical failures in the United States of LPLF stop joints (special joints required to provide hydraulic isolation between cable sections because of elevation differences or maximum section lengths that can be provided by reservoirs). The stop joints have stepped insulation and a series of concentric barriers to provide radial electrical strength in liquid-filled sections of the joint. This assembly is very sensitive to contamination from the pressurizing liquid. Contamination has caused tracking along the stepped insulation resulting in electrical failure.

Stop joints typically have insulating cones over the stepped paper insulation. These cones have failed, either due to improper installation or to pressure surges due to a fault in the insulation.

3.2.5 Moisture in the Insulation

LPLF cables are more susceptible to moisture entry than are pipe-type cables. The 15-45 psig (103-310 kPa) pressure is much lower than the pressures used in HPLF lines and the LPLF cables have many soldered connections that are subject to stress cracking---as is the cable sheath itself. In addition, the liquid is in the core of the cable, and therefore in contact with the inner layers of paper insulation that operate under the highest electrical stresses. (The outer layers of paper insulation for pipe-type cables are the ones in contact with dielectric liquid, and the outer layers have lower electrical stress than the inner layers.)

3.2.6 *Mechanical Problems*

Thermo-mechanical Movement

The greatest thermo-mechanical problem for LPLF cables is fatigue of the lead sheath due to cable expansion and contraction during temperature changes that result from load cycling. Older cables did not all have fatigue-resistant lead sheaths, and the lead wipes at the bases of terminations and the ends of joint sleeves are susceptible to cracking with mechanical stress. This does not compromise the mechanical integrity of the cable *per se*, but it does often lead to moisture intrusion.

One utility on the U.S. east coast had numerous problems with mechanical movement causing cracks in the lead wipes at the ends of splice sleeves -- giving fluid leaks and allowing moisture intrusion. They developed an epoxy encapsulation that was effective in greatly reducing, but not completely eliminating the problem. The approach to racking of the splices and cables in manholes had a large effect on the tendency for the lead wipes to crack and the effectiveness of the repair. These repairs extended the life of the LPLF cables by several decades, but they were eventually replaced.

External Damage

LPLF cables do not have the mechanical protection afforded by the steel pipe of a pipe-type cable and are therefore more susceptible to dig-in, even if the LPLF cables are in a concrete-encased duct bank.

3.2.7 *Leaks*

Leaks are a problem for many LPLF circuits; the causes are discussed earlier in this section of the report. Leak rates are typically very small, but the volume of fluid in reservoirs is also small compared to HPLF lines. If alarms are not working properly, loss of fluid could cause an electrical failure that is much more expensive and time consuming to repair than a leak. Ongoing problems with leaks and with reservoirs has been the cause of cable replacement (end of service life) on many LPLF circuits in the United States.

3.2.8 *Sheath Bonding Systems*

Most LPLF cables are single-conductor. Current flowing in the conductor causes induced currents in the sheath that de-rate the cable if the sheaths are solidly bonded and grounded at multiple locations. Therefore, most circuits divide the length of the circuit into sections using sheath insulators at splices. The individual sections are solidly grounded at one end and grounded through sheath voltage limiters at the other end, or the three sheaths may be cross-bonded. Sheath currents are generally negligible, and the sectionalizing limits induced voltages to acceptable levels.

The sheath bonding system requires maintenance to ensure the bonding leads are connected properly to avoid circulating currents that can overheat the cable, and the sheath voltage limiters must be inspected periodically. In addition, the cable oversheath (jacket) must be tested periodically to check for damage.

These maintenance requirements, in addition to the other maintenance requirements described in this section, are a consideration for the replacement programs described in Chapter 4.

3.2.9 Availability of Replacement Cable

XLPE cables are replacing paper-insulated cables worldwide, including LPLF cables. However, there are still a few LPLF cable suppliers outside of North America. There are large amounts of paper-insulated cables produced for submarine applications, so availability of LPLF cable should continue for several years. [4]

4

NORTH AMERICAN EXPERIENCE IN OPERATION/REPLACEMENT OF HPLF AND LPLF CABLES

4.1 HPLF Cable Systems

4.1.1 Cables

Replacing HPLF cables because they have reached the end of their service life is extremely uncommon, even though there are thousands of miles (km) that have exceeded their original design life. Replacement because of corrosion of the cable pipe is more common, but is still infrequent. Examples of cable replacement are given below.

A major east coast utility recently replaced more than 100 circuit-miles (more than 160 circuit-km) of 230-kV HPFF cable. There were several considerations for this major undertaking:

- The original cable had several thermo-mechanical bending failures in splices and in the cable itself, and many more "removals before failure." The utility evaluated the profile drawings of its pipe-type cable circuits and used the results, along with results of x-ray testing of splices, to prioritize cable replacement.
- There had been a few major intrusions of water into the pipe. Generally only a few manhole-to-manhole sections are replaced, but in at least one case, water intrusion was a consideration for replacement of the entire circuit.
- Additional power transfer was needed; the utility replaced 2000-kcmil (1000 mm^2) 230-kV cable with 3000-kcmil (1500 mm^2) 345-kV laminated paper-polypropylene insulation. The cable will be operated at 230 kV until 345 kV is needed.
- The entire length of pipe was inspected with a "smart pig" that evaluated wall thickness. Several corrosion spots were detected and repaired, and a few approximately 45-ft (14-m) sections of pipe were replaced because of dents or excessive corrosion.

A different east coast utility replaced high-pressure gas-filled pipe-type cable with extruded-dielectric cable on a bridge crossing where road salt caused numerous areas of severe corrosion.

A third east coast utility has areas where transition joints are used from pipe-type cable to XLPE-insulated cable because manhole-to-manhole sections of the original pipe-type cable had to be replaced.

Several major cable-using utilities were contacted to ascertain their policies regarding determining end of service life. None of the utilities had general procedures or criteria for determining ESL. In each case, the utility stated that cable replacement (equivalent to ESL) is determined on a circuit-by-circuit basis based upon the number of operating problems experienced on that circuit.

There have been a few cable section replacements because of localized overheating, e.g. due to tree roots depleting moisture from the cable backfill.

In addition, there have been a few occasions where complete circuits of HPLF cable were replaced with equivalent HPLF cable because the original cable had too many problems due to manufacturing, installation, or operation.

Note that EPRI has an active program to help utilities facilitate replacing pipe-type cable with extruded-dielectric cable, for example by evaluating reduced-insulation thickness cables to allow larger conductors to be pulled into existing steel pipes. EPRI also has a program to develop and demonstrate methods to burst existing cable pipes and pull-in new fusible PVC or steel pipes and allow larger conductors to be installed. Availability of these procedures may affect the economic decisions on determining end of service life on existing circuits.

There are replacement programs for cable system accessories as described below.

4.1.2 Terminations

The Ohio Brass Company produced two-chamber HPLF terminations through 1960 for voltages up to 161 kV. These terminations are known to be prone to leaks at gasket connections. Replacement gaskets can be obtained and installed with some success, but in many cases the terminations are replaced with modern terminations from G&W Electric or Underground Systems, Inc. An adapter plate is required; several plate designs exist and are specific to the model number of the Ohio Brass terminations.

A least one U.S. utility has an ongoing program to replace all Ohio Brass terminations on one or possibly two circuits per year, until there are no more of the original terminations in service.

4.1.3 Splices

There have been many splice failures on TMB cables over the years because of the thermo-mechanical movement or thermo-mechanical bending conditions as described in Chapter 3. If problems are suspected, utilities take fluid samples for dissolved gas analysis and also x-ray the splices through their steel casings. It is possible to determine damage, and repairs are made: the line is de-energized and tagged, fluid frozen either side of the splice, liquid drained, casings opened, cables and splices inspected and repairs made, additional supports installed to prevent future unwanted movement, the casings replaced and welded, the drained section evacuated, fluid introduced, the line pressurized and returned to service.

At least one utility has proactively opened casings to inspect the splices, and has chosen to install additional supports (spiders) on all splices on selected circuits based on their findings.

4.1.4 Pressurizing Plants

Many utilities are replacing 40-60 year old pressurizing plants with new plants, or at least new "skids" which are freestanding assemblies consisting of pumps, controls, alarms and communications equipment. This replacement can be carefully designed to fit within the footprint of the original plant equipment, and removing the original plant and installing the new skid can be done quickly. The reservoir tank is reused.

This replacement of the plant or skid is done because of leaks and high maintenance on the older plants, the older plants often have asbestos insulation on wiring and have mercury in switches, manually operated gate valves and they have outdated alarm/control units. New plants typically have reliable ball valves, and can have remote monitoring of fluid pressures; fluid levels in the reservoir tanks, etc. and can have sophisticated touchscreen controls.

4.1.5 Cathodic Protection Systems

Cathodic protection systems are required to protect the pipe from corrosion if there are problems with the corrosion coating. Antiquated systems such as resistor-rectifiers, as well as more modern rectifier systems, are being replaced with newer rectifiers, possibly with remote monitoring of rectifier voltages and currents as well as cathodic protection pipe-to-soil potentials. Anode beds commonly have a life of 20-30 years, so it is sometimes necessary to replace them with new anode beds even if the original rectifier stays in place.

In addition to regular maintenance, utilities typically have a cathodic protection study performed by a qualified firm with a NACE-certified corrosion engineer, that will evaluate all components, check pipe-to-soil potentials, determine condition of anode beds, and cathodic protection test stations, etc. That firm will recommend replacement components as needed.

4.2 LPLF Cable Systems

LPLF cables, as HPLF cables, are seldom replaced because the insulation system has reached the end of its useful life; laboratory analysis of cables more than 80 years old have showed that the fluid/paper insulation is in good condition. Lines installed in the 1920s have been replaced only recently--because of excessive leaks and excessive maintenance of the cables, splices, reservoirs, and alarm systems as well as lack of qualified personnel for making lead wipes.

Many U.S. users of LPLF cables have programs to replace those cables with extruded-dielectric cables. The earliest and most ambitious project was in Chicago in the late 1990s, undertaken because of multiple failures and high maintenance [3]. The utility worked with a cable supplier to develop cables and splices that would fit into existing ducts and existing manholes. The utility replaced 99 miles (160 km) of cables and accessories into the existing ducts, using a reduced insulation thickness.

A west coast utility has a program to replace one or perhaps two LPLF cable circuits with XLPE-insulated cables each year. The utility has experienced several stop joint failures believed to have caused by fluid starvation due to sludging of the fluid in the reservoirs and connecting tubing. The utility is also having trouble maintaining the alarm systems on the circuits.

Terminations have not been a particular problem on LPLF circuits. Straight-through splices have generally been trouble free. Stop joint splices have been sources of failure and require high maintenance for the reasons described in Section 3.2.2.

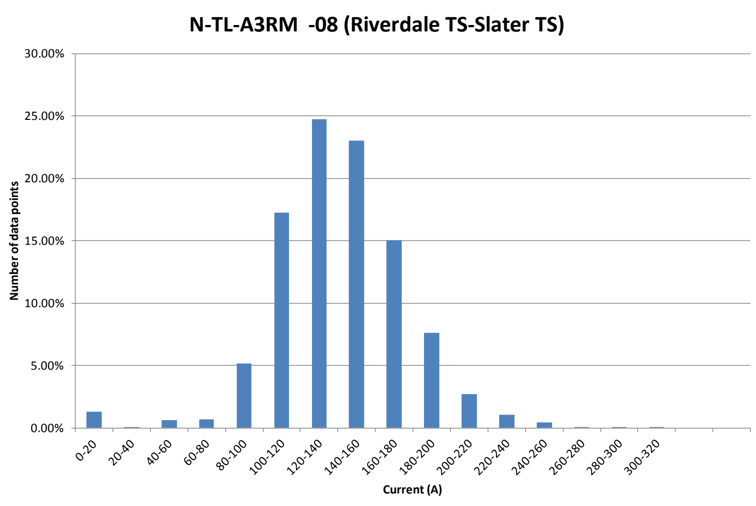
5
PROCEDURES FOR ANALYSIS OF END OF SERVICE LIFE

5.1 Thermal Aging of Impregnated Paper Insulation

Initial review of loading data provided by Hydro One indicated that the degree of thermal aging is low, even for the older cables. To verify this conclusion, we calculated the approximate degree of aging using procedures described in [1]. The procedure is summarized as follows for both HPLF and LPLF circuits:

- Obtain available information on Hydro One calculation of ratings for cables
- Obtain an indication of historical loading on the lines
- Use the Arrhenius aging relationship described in Appendix A to determine the degree of aging, identified as the number of years of cable life used versus the number of years the line has been in service. To be conservative, we assume that the loading throughout the cable lifetime has been just as high as for the last few years for which Hydro One provided data. This should be quite conservative since it the loading 40-50 years ago was probably much lower than present loading.
- Estimate the actual cable life based upon this historical loading.

Hydro One provided a summary of recent loading history. This document clearly shows that loads were almost always far below the cable rating for the three-year study period, January 1, 2014, through December 31, 2016. Durations were short in the few instances where loading exceeded the rating. Figures 5.1 and 5.2 show typical load distributions.



The continuous current rating of this cable is 690 A

Figure 5.1
Bar chart showing distribution of loading, HPLF circuit

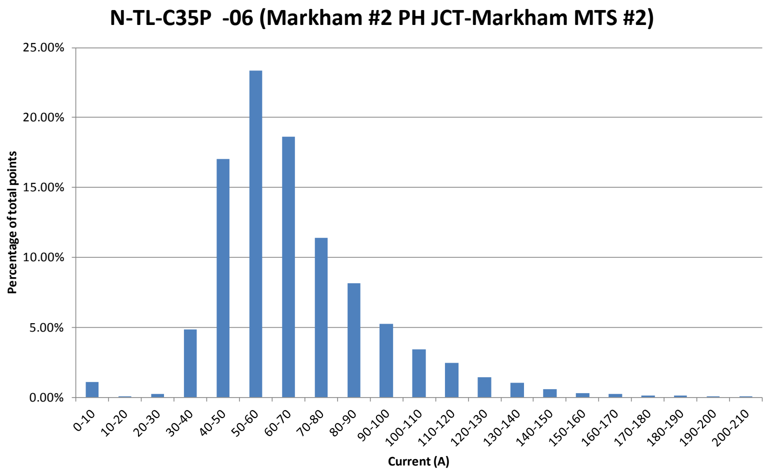


Figure 5.2
Bar chart showing distribution of loading, LPLF circuit

Hydro One provided hourly historical load data for selected circuits, and calculations were made to determine average loading, peak loading, and daily load loss factors. These calculations confirmed the very low load values given in the Hydro One graphs. Load factors and loss factors (load factor of the losses) were consistent with circuits on major transmission systems.

A summary of calculation of insulation aging for the circuit of Figure 5.1 is given below, assuming summertime conditions with an ambient earth temperature of 20 °C:

Circuit rating:	**690 A at 80°C conductor temperature**
Conservative current used for calculations:	**200 A (cable operated below that loading 90 percent of the time)**
Calculated temperature at 200 A	**25°C**
Lifetime used	**0.5 year**
Lifetime used at 65 °C conductor temperature	**10 years**

This circuit has used a negligible amount of its thermal-aging lifetime after 53 years in service. However, the 25°C temperature is below the accepted range of the Arrhenius aging relationship. Even if we assume that the cable has operated at 65 °C for the last 53 years, only ten years of thermal-aging lifetime has been used.

Conditions are similar for all of the circuits for which Hydro One provided historical loading data. We can safely state that the cable insulation is nowhere near their end of service life as regards thermal aging of the insulation. The very low percentages of rated load also result in low amounts of thermo-mechanical movement, which reduces the likelihood of thermo-mechanical bending or thermo-mechanical movement failures.

5.2 Evaluation of DGA and Other Data Relating to End of Insulation Service Life

Thermal aging should be low, as described in Section 5.1. However, there could be "hot spots" that cause localized high cable temperatures and therefore higher levels of aging. Dissolved Gas Analysis evaluates gases that are indicative of thermal aging of the paper and of the dielectric liquid. In addition, DGA provides indication of items such as electrical "spitting" because of problems with cable shielding.

Excessive moisture in the cable paper can cause heating and electrical failure. In a few occasions at U.S. utilities, several sections of cable had to be replaced because of high moisture (free water.) In one case, enough manhole-to-manhole sections had free water that the utility decided to remove the cable, swab and dry the pipe, and re-conductor the pipe. Data provided by Hydro One showed just a few liquid readings with high moisture content--not enough to affect overall performance of the circuit. It is sometimes feasible to set up an in-line liquid circulation and degassing system to remove moisture and contaminants that might be present in the dielectric liquid.

5.2.1 HPLF Systems

Repair of isolated leaks from a HPLF cable pipe may have environmental implications and be costly to locate and repair, but leaks do not determine the end of service life of a pipe-type cable unless they are too numerous to repair or are in inaccessible locations. Review of data provided by Hydro One indicates that corrosion leaks are not a problem and therefore do not affect ESL of the pipe-type cable systems.

5.2.2 LPLF Systems

Data provided by Hydro One did show a significant number of leaks from the LPLF cable circuits. As stated several times in the present report, this is not uncommon for LPLF cables and has been the major reason for replacement of this type of cable. Replacement with XLPE-insulated cables is underway on a scheduled basis at several major U.S. users of LPLF cable. Many of these circuits were installed more than 80 years ago. Until the replacements are complete, the utilities repair the leaks and occasional electrical failures that occur.

5.3 End of Service Life of Accessories

As described in Chapter 4, end of service life is seldom determined by problems with any accessories such as terminations, splices, pressurizing plants and LPLF reservoirs, cathodic protection and sheath bonding systems. Individual components can be rebuilt or replaced if failures occur or maintenance requirements become too high.

5.4 Testing to Determine Indicative Data for Cable Condition

Procedures that are used include the following:

- Perform an "ampacity audit" of the system to determine the approximate temperature history and allow calculating the degree of thermal aging. The audit consists of the following items:

- Evaluate cable rating data used during initial system design
    - Evaluate current plan and profile vs. that when the cables were installed
    - Measure soil thermal resistivity and compare with original design data
    - Evaluate loading history
    - Calculate temperatures along cable circuit, concentrating on "hot spots"
    - Using Arrhenius aging relationship to determine the number of years of aging that have occurred. This value is almost always much lower than the number of calendar years in service.
- Perform dissolved gas analysis (DGA) of the dielectric liquid. A great deal of research has been performed on aging of oil/paper insulation systems and on implications of various gases and ratios of gases on the condition of the cable. Readings at one point in time are marginally useful; readings should be repeated and trends in results evaluated. The frequency of testing is determined based upon any trends that are observed. If all values are stable, tests every five years are probably acceptable. If there is an increasing value of any of the critical dissolved gases, test frequency should be increased. If a critical value is observed, e.g., high acetylene levels, immediate action may be prudent.
- Thermo-mechanical movement (TMM) and thermo-mechanical bending (TMB) are one of the most common causes of the (infrequent) failures on paper-insulated cables. The cables move with temperature changes. In some cases this movement causes cables to jam against the reducers in splice casings, fatigue cracks in LPLF cable sheaths, or insulation tapes displaced causing "soft spots". Evaluation of plan and profile may indicate potential problem areas, and x-rays can be taken at accessible locations such as splice casings to see if damage has occurred.
- Perform field dissipation factor measurements as needed. There has been some success in measuring dissipation factor of the cable. This test measures the charging current of the cable which is a function of the geometry and the dissipation factor. An increase in dissipation factor with time is an indication of possible moisture in the paper or aging of the paper. This test only indicates average conditions for the full length of the cable.
- Ideally, a sample of cable can be removed from the circuit. If this is possible, laboratory evaluation of paper properties can provide an indication of degree of aging. EPRI conducted a major study of cable aging that gives good indications of parameters to measure [1]. It is of course a major undertaking to obtain a cable sample; this is usually done when there is a cutover or extension of a cable circuit, or if sections of cable must be replaced because of cable failure. There is no guarantee that the retrieved sample is representative of the worst condition along the circuit---which could occur some distance from the sample.
- Perform buried steel pipe corrosion surveys for pipe-type cable systems to ensure proper operations of cathodic protection systems and effectiveness of the protection to each section of the buried steel pipes, and to assess pipe coating conditions and investigate remediation methods and apply as needed.
- Perform sheath jacket integrity tests of low-pressure fluid-filled systems to assess conditions for long-term performance.

6
SUMMARY AND RECOMMENDATIONS

Hydro One provided a great deal of historical data on its high-pressure liquid-filled (HPLF) pipe-type cable circuits and its low-pressure liquid-filled (LPLF) self-contained cable circuits. Review of that information, calculation of critical parameters such as degree of thermal aging of the insulation, and evaluation of experience of other users of these cable types, permitted making conservative estimates of the design end of service life (expected service life – ESL) for both HPLF and LPLF cables.

6.1 High-pressure Liquid-filled Cables

Circuit loading has been significantly lower than the cable ratings. As a result, the thermal aging of the cable insulation is minimum. If an extremely conservative average operating temperature of 65°C is used for determining the degree of aging, the oldest HPLF cable has used only ten years of the presently assumed 50 year life. If the cables are loaded to their full rating in future operations, they should have another 40 years of life. Although analysis of loading data indicates that this is a conservative number, we recommend that Hydro One assign an additional 20 years to the design life, to give a 70-year design life. Hydro One should repeat the analysis described in this report as the oldest circuits approach the 70-yr age.

No leaks have been reported on the cable pipes, indicating that the corrosion coating and cathodic protection system are working well and will not limit the service life of the cable system. No unusual difficulties are reported on the corrosion protection system, splices, terminations, or dielectric liquid. With proper maintenance, these components will not limit the 70-year design life as recommended.

We recommend that Hydro One establish a 70-year period for the design end of service life for its HPLF cables, and that the cable condition be reviewed five years before that time. Hydro One should continue its maintenance testing such as dissolved gas analysis, fluid moisture content, and effectiveness of corrosion protection systems for buried steel pipes and manhole pipe sections. If any test results indicate potential problems, Hydro One should investigate the cause and take corrective action.

6.2 Low-pressure Liquid-filled Cables

Loading on the LPLF circuits has also been much lower than design ratings, and the life of the cable insulation should exceed 70 years, as is the case for the HPLF cables.

However, leaks on several of the circuits and difficulties with the pressurizing system, indicate that Hydro One should consider replacing these circuits within the next ten to twenty years.

We recommend that Hydro One establish a 70-year period for the design end of service life for its LPLF cables, and that the cable condition be reviewed five years before that time. Hydro One should continue its maintenance testing such as dissolved gas analysis, fluid moisture content, and jacket integrity tests. If any test results indicate potential problems, Hydro One should *investigate the cause and take corrective action. Hydro One should carefully monitor the condition of the lead sheaths and the liquid reservoirs, and should begin designing the replacement of LPLF cables with modern generation XLPE cables and replace the LPLF cables within ten to twenty years.*

7
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A

THERMAL AGING OF PAPER CABLE INSULATION

EPRI report "Transmission Cable Life Evaluation and Management", which is Reference 1 in Section 7, has a very comprehensive analysis of cable aging, with detailed theoretical evaluation and results of a great many tests on pipe-type cables. The following sections are taken from that 474-page report.

It is a commonly held belief among cable engineers that there is little aging in HPFF cables systems that have been operated under typically conservative utility conditions which result in conductor temperatures of 40 °C to 60 °C. Moreover, the upper end of these already conservative temperatures may be experienced by a cable only in the peak-use periods such as summer air-conditioning loads. Their life expectancy may in fact be much longer than 40 years. This project has been designed to verify or disprove the critical temperature/aging relationship.

It is possible to estimate loss-of-life and remaining cable life based on operating conditions and a semi-empirical model developed as a result of this project. This model is based on an Arrhenius relationship for loss of degree of polymerization for tapes adjacent to the conductor and an empirically determined mechanical bending factor.

HPLF cables are characterized by long life. Results of this analysis indicate that the cables have a remaining life of approximately 250 years assuming that current operating conditions are continued.

The Arrhenius relationship and the so-called “inverse power law” have been applied to study aging respectively under thermal and electrical stresses, with good results. Estimate loss of life based on thermal history of cables, using EPRI statistical model (EPRI TR-111712):

$$LossOfLife = t \cdot e^{-K \cdot \frac{85 - T_C}{273 + T_C}}$$

where:

t = Time elapsed at temperature T_C, years
T_C = Conductor temperature, °C
K = Rate of property loss = 10,003/(273+85) = 27.9
(by Degree of Polymerization Degradation Model)

The equations above, and the parameters given in the table, were used to analyze the degree of aging of the Hydro One cables. A simplification is that the aging rate doubles for each 9 Celsius degree increase in operating temperatures.

ELECTRIC POWER RESEARCH INSTITUTE

Review of Utilities' Management of Air Blast Circuit Breakers

Current Industry Practices

Review of Utilities' Management of Air Blast Circuit Breakers

Current Industry Practices

Technical Update, February 2018

EPRI Project Manager
B. Desai

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The Electric Power Research Institute (EPRI), prepared this report

Electric Power Research Institute (EPRI)
1300 West W.T. Harris Blvd.
Charlotte, NC28262

Principal Investigators
B. Desai
Walter Barfield III

Coplanar Consulting, LLC
Yardley, PA 19067

Principal Investigator
M. Lebow

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EXECUTIVE SUMMARY

This report presents the findings of a recent web survey conducted by EPRI on air blast circuit breaker (ABCB) asset management practices and concerns.

High voltage ABCBs are an older technology that relies on complex mechanical and pneumatic subsystems for proper operation. ABCB technology allowed for the development of relatively compact high voltage and high current breakers and has generally performed well over decades of service. However, due to their complex design with many parts and seals, ABCBs require extensive periodic maintenance. Moreover, because ABCBs are an older technology, spare parts and mechanics experienced in their maintenance are not always readily available. For these reasons, many utilities have decided to retire all of their ABCB fleets. Other utilities are considering such actions but may be restricted by various constraints.

The survey was conducted to collect industry experience and industry plans for air blast circuit breakers with the following objectives:

- Assess industry attitudes on retaining in-service air blast circuit breakers
- Understand how peer companies are responding to ABCB operations and maintenance challenges

Keywords

Air Blast Circuit Breakers

Asset Management

Industry Practices

CONTENTS

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1
INTRODUCTION

This report presents the findings of a recent web survey conducted by EPRI on air blast circuit breaker (ABCB) asset management practices and concerns.

High voltage ABCBs are an older technology that relies on complex mechanical and pneumatic subsystems for proper operation. ABCB technology allowed for the development of relatively compact high voltage and high current breakers and has generally performed well over decades of service. However, due to their complex design with many parts and seals, ABCBs require extensive periodic maintenance. Moreover, because ABCBs are an older technology, spare parts and mechanics experienced in their maintenance are not always readily available. For these reasons, many utilities have decided to retire all of their ABCB fleets. Other utilities are considering such actions but may be restricted by various constraints.

The survey was conducted to collect industry experience and industry plans for air blast circuit breakers with the following objectives:

- Assess industry attitudes on retaining in-service air blast circuit breakers
- Understand how peer companies are responding to ABCB operations and maintenance challenges

The survey was sent to more than 20 transmission companies. Three companies indicated that they did not have air blast circuit breakers. Five companies responded and their responses serve as the basis for this report.

Report Organization

In addition to this Introduction, the report includes the following chapters:

Chapter 2: Air Blast Circuit Breaker Designs

Chapter 3: Air Blast Circuit Breaker Survey Findings

Chapter 4: Conclusions

2
AIR BLAST CIRCUIT BREAKER DESIGNS

Description

Some understanding of ABCB design will help to frame the asset management issues. Air blast breakers were developed in parallel with oil breakers, mainly in Europe during the1940s and 1950s, when oil was scarce. Oil was not an issue in the United States. Instead, fire was an issue to some utilities and interrupting capabilities at higher transmission voltage was a bigger issue. During the 1950s, air blast circuit breakers were installed in many parts of the world, in competition with oil designs. There are two basic design types; in this paper, they are termed the early, dead tank type and the later, permanently pressurized-head, live tank type. Most all of the remaining in-service ABCBs are this design.

The later type formed the basis of many of the international grid systems of the mid-1960s, when system voltages of ≥400 kV, up to 4000A continuous current, and 63 kA short circuit were required. Due to these ever-increasing power system voltages, the physical size limitations of oil breakers, coupled with the large quantities of insulating oil that would be required at the higher voltages, the use of oil circuit breakers became unrealistic. Development of the existing air-blast technology was necessary. Ultimately, these permanently pressurized-head design types of air-blast circuit breakers ranged in voltage class from 115 to 800 kV and in interrupting rating from 40,000 to 80,000 A. These air-blast circuit breakers have extremely rapid interrupting times, typically opening the main contacts within two cycles (33.3 ms at 60 Hz) from trip initiation.

Although various designs exist, the permanently pressurized-head, air-blast circuit breakers are also of the live tank type. On these designs, the high-pressure air is used for electrical insulation and arc-extinguishing purposes, hence the term *permanently pressurized-head*.

Interruption – Later Type (Permanently Pressurized-Head)

Permanently pressurized-head designs use dry air under pressure to quench the arc that is formed during an opening operation. This air is stored around the contacts within one of the numerous series heads that make up a pole (phase) of the circuit breaker. As the contacts separate and the current attempts to maintain its flow, an arc is formed. However, by design, the arc is directed in a designated course. With precision timing, a valve within the interrupting chamber opens, allowing some of the air contained within the breaker to exhaust to atmosphere, directly through the path of the arc. At the opening of the blast valve, the interior of the breaker rapidly becomes somewhat depressurized. This depressurization results in a blast of air that cools the arc, forcing it away from the parting contacts and out the arc chutes or arcing tubes. The arc is eliminated by being elongated and cooled beyond its ability to maintain itself. With adequate dielectric strength between the open contacts, the exhaust valve is closed, and the head is re-pressurized from the local receiver. The pressure in these types of circuit breakers is required to be maintained even when the breaker was in the open position. The distance between the open contacts and the operating rods would flash over to ground if the pressure was not present.

On all permanently pressurized-head air blast circuit breakers, the interrupter heads are modular. Normally, a particular interrupting head can be transferred from one position or breaker to another position or breaker if the current carrying capacity, interrupting capability, and accessory equipment are the same. The move could be successfully accomplished even if accessories are added, removed, or changed to meet the requirements of the new position, as long as the ratings are the same at both locations. Because of the modular design, all that is required of the manufacturer to increase the voltage of a particular type of breaker is to add the modular interrupter heads in series, within a phase, to give the breaker the desired capability. Of course, the insulation level from phase to ground must be increased as well. Therefore, the height of the interrupter support columns and drive rods must be increased. The added height is required due to the basic insulation level necessitated by the increased voltage. Interrupter support columns are hollow ceramic insulators of high mechanical (as well as electrical) strength. The interrupter operating rods pass through the opening of the center of the support column. In some cases, this contains high-pressure air; in others, the high-pressure air is within a separate tube housed within the support column. The zone between the tube and the column is kept dry by a low-pressure conditioning air system. In one manufacturer's design, the space is filled with SF_6 gas as electrical insulation. As an example of the difference in stack height, a typical 800-kV breaker reaches 41ft (12.5 m) from ground level to the top of the interrupter (and, depending on the version of the breaker, uses either four or five interrupters per phase). In contrast, a 138-kV breaker of the same type is less than 20 ft (6 m) to the top (and has only one interrupter per phase, but of the same basic type as that of the 800-kV breaker).

Interrupter Types

All modern air-blast interrupters use the axial blast principle by forcing the arc to burn on a line parallel with the axis of the contacts' travel. On some designs, the arc is initiated transversely before transferring to become axial before extinction.

The later designs of the permanently pressurized-head air-blast interrupters became extremely complex to achieve the high short-circuit interruption levels and rapid operating times. These are too complex to describe in detail, and the principle is adequately explained by consideration of the simplest forms. There are two basic axial nozzle systems: 1) a mono-blast or single-flow system, in which the air subjects the arc to one single directional blast, and 2) a duo-blast or double-flow system, in which the air blast is divided equally through two nozzles. The blast flows into the arc chamber from opposite directions and is exhausted through ports in line with the contact movement. A variant of this system is the duo-blast system in which one nozzle orifice is made smaller than the other.

The mono-blast and duo-blast systems are built into an insulating enclosure, which is supplied with compressed air. The air supply to the nozzles is controlled by a blast valve placed on the upstream side of the contacts, somewhere between the nozzles and the supply source.

The exhaust passages downstream are controlled by exhaust ports or valves. Each of these arrangements must admit compressed air to the nozzles while the exhaust passages are open and then shut off the air supply to prevent the pressure reservoirs from being exhausted.

When the interrupters are pressurized in the open position only, both the blast valves and the exhaust valves are used. The blast valves admit the air to the nozzles, and the exhaust values stop the flow and keep the interrupter pressurized. One blast valve can supply more than one interrupter at a time, and one exhaust valve can be arranged to control two adjacent exhaust passages in a twin interrupter unit.

When the interrupter chambers are permanently pressurized (that is, in closed and open positions), exhaust valves are used. The exhaust valves are used either on their own or in combination with blast valves placed across the electrodes. One exhaust valve can serve two interrupters, but in this case, separate blast valves must be provided for each interrupter.

Insofar as nozzle systems and pressurization are concerned, air-blast interrupters can be divided into nine types—that is, mono-blast, partial-duo-blast, or duo-blast, each pressurized in one of the three ways:

- During interruption only
- During interruption and in the open position
- Permanently

In circuit breakers that have both high-pressure air and SF_6 gas separated by gaskets, high-pressure air can leak into the SF_6 gas space. The high-pressure air contains far greater amounts of moisture than the SF_6 gas spaces are intended to contain. Therefore, leakage of air into these spaces can set up the potential for a catastrophic failure. In some designs, such leaks are from seals that are difficult to replace with normal maintenance. In such cases, this leaking seal can be considered a life-limiting factor because it can be expected to involve major dismantling to correct the seal; the disruption and cost might indicate that replacement is more sensible.

Further, with any air-blast circuit breaker, moist air entry into dry air chambers will degrade the insulating quality and arc−quenching capability. Wet air can cause flashovers, restrikes, or a slow deterioration of insulated parts within the circuit breaker. If slow deterioration occurs and plastics are involved, corrosive gases can be formed that will attack copper, aluminum, or silver-plated surfaces. This corrosion can include contacts, valves, seating surfaces, and all interior parts.

3

AIR BLAST CIRCUIT BREAKER SURVEY FINDINGS

EPRI developed a web-based survey to gather information about current utility thoughts regarding maintaining ABCB fleets and recent past actions regarding retiring ABCBs. All US utilities known to have or to recently have had ABCBs in service were invited to participate. The survey was sent to more than 20 transmission companies. Three companies indicated that they did not have air blast circuit breakers. Five companies responded and their responses serve as the basis for this report.

Fleet Characteristics – Installed Population

Based on the responses from the utilities surveyed, Table 3-1 and Table 3-2 show the counts for installed air blast circuit breakers by Make and Voltage and by Make and Age, respectively. The count of air blast circuit breakers currently installed is 280 in the responding utilities' fleets and consisted of GE (80), ABB (29), and Cogenel (171). Of this installed population, 99.6% are greater than 30 years of age with 74.3% being greater than 40 years of age.

Table 3-1
Count of Installed Air Blast Circuit Breakers by Make and Voltage (5 Respondents)

Make	Voltages (kV)					
	138	161	230	345	500	765
GE	12	0	66	2	0	0
ABB (Brown Boveri & Cie (BBC))	0	0	12	9	8	0
Cogenel (Delle Alsthom)	78	0	12	24	39	18
Allis-Chalmers	0	0	0	0	0	0
Merlin Gerin	0	0	0	0	0	0
Hitachi	0	0	0	0	0	0
Other	0	0	0	0	0	0

Table 3-2
Count of Installed Air Blast Circuit Breakers by Make and Age (5 Respondents)

Make	Age(Yrs)		
	< 30	30 to 40	>40
GE	0	1	79
ABB (Brown Boveri & Cie (BBC))	0	16	13
Cogenel (Delle Alsthom)	1	54	116
Allis-Chalmers	0	0	0
Merlin Gerin	0	0	0
Hitachi	0	0	0
Other	0	0	0

Fleet Characteristics – Replaced Population

Table 3-3 shows the number of air blast circuit breakers replaced in the last ten years and the principal reason for replacement of those breakers. By summing the 280 installed breakers in Table 3-1 and 556 replaced breakers in Table 3-3, the count of installed air blast circuit breakers ten years ago was 836. Over the last decade, this represents a 66.5% reduction in the number of air blast circuit breakers installed in the utility fleets with all of the utilities having performed programmatic replacements of these types of breakers. In Table 3-4, it is shown that the primary reasons for the programmatic replacements by utilities were founded upon excessive operational and maintenance costs and an unacceptable level of reliability/availability. In Table 3-5, utilities were asked to select the principal reason for not performing programmatic replacement on air blast circuit breakers. Since none of the surveyed utilities provided answers for this question, it implies that all surveyed utilities have performed programmatic replacement of air blast circuit breakers.

Table 3-3
Count of Replaced Air Blast Circuit Breakers by Make and Principal Reason for Replacement (3 Respondents)

Make	Count	Principal Reason Replaced		
		Programmatic Replacement	Individual Condition/Reliability	Insufficient Rating
GE	204	X		
ABB (Brown Boveri & Cie (BBC))	96	X		
Cogenel (Delle Alsthom)	251	X		
Hitachi				
Merlin Gerin				
Allis-Chalmers				
Other	5	X		

Table 3-4
Reasons for Programmatic Replacement of Air Blast Circuit Breakers (3 Respondents)

Make	Programmatic Replacement			
	Unacceptable Reliability/Availability	Excessive Costs	Insufficient Rating	Other
GE	X	X		
ABB (Brown Boveri & Cie (BBC))	X	X		
Cogenel (Delle Alsthom)	X	X		
Hitachi				
Merlin Gerin				
Allis-Chalmers				
Others	X	X		

Table 3-5
Reasons for No Programmatic Replacement of Air Blast Circuit Breakers (0 Respondents)

Make	Reasons for No Programmatic Replacement			
	Acceptable Performance	Capital Unavailability	Outage Unavailability	Other
GE				
ABB (Brown Boveri & Cie (BBC))				
Cogenel (Delle Alsthom)				
Hitachi				
Merlin Gerin				
Allis-Chalmers				
Others				

Utility Experience

For this study, utilities were asked to rate their experience with air blast circuit breakers with respect to single pressure gas breakers. The three categories for rating utility experience were reliability and maintenance practices, cost/difficulty of performing minor maintenance, and cost/difficulty of performing major maintenance. The following subsections detail the gathered responses for each utility.

Reliability and Maintenance Practices

Table 3-6 shows that 1 of the 4 utilities surveyed found that air blast circuit breakers are less reliable than single pressure gas breakers while 3 of the 4 utilities found them to be much less reliable.

Table 3-6
Reliability of Air Blast Circuit Breakers to Single Pressure Gas Breakers (4 Respondents)

Option	Utility 1	Utility 2	Utility 3	Utility 4
Much Less Reliable		X	X	X
Less Reliable	X			
Same				
More Reliable				
Much More Reliable				

Cost/Difficulty of Performing Minor Maintenance

Table 3-7 shows that 1 of the 4 utilities surveyed found that air blast circuit breakers are much more costly/difficult to perform minor maintenance than single pressure gas breakers while 3 of the 4 utilities found them to be more costly/difficult.

Table 3-7
Cost/Difficulty of Performing Minor Maintenance of Air Blast Circuit Breakers Compared to Single Pressure Gas Breakers (4 Respondents)

Option	Utility 1	Utility 2	Utility 3	Utility 4
Much More Costly/Difficult			X	
More Costly/Difficult	X	X		X
Same				
Less Costly/Difficult				
Much Less Costly/Difficult				

Cost/Difficulty of Performing Major Maintenance

Table 3-8 shows that 1 of the 4 utilities surveyed found that air blast circuit breakers are more costly/difficult to perform major maintenance than single pressure gas breakers while 3 of the 4 utilities found them to be much more costly/difficult.

Table 3-8
Cost/Difficulty of Performing Major Maintenance of Air Blast Circuit Breakers Compared to Single Pressure Gas Breakers (4 Respondents)

Option	Utility 1	Utility 2	Utility 3	Utility 4
Much More Costly/Difficult	X	X		X
More Costly/Difficult			X	
Same				
Less Costly/Difficult				
Much Less Costly/Difficult				

Current Maintenance Practices

Utilities were asked several questions on current maintenance practices of in-service air blast circuit breakers. The responses for each utility by question are shown in Table 3-9.

Only half of the utilities surveyed have dedicated crews to perform internal inspections/refurbishments on air blast circuit breakers. None of the utilities have dedicated shops to maintain/overhaul air blast circuit breakers and only one-quarter have dedicated contractors to maintain/overhaul these breakers. Also, there was a consensus that none of the utilities have a reliable source of available spare parts.

Utilities were asked if they followed vendor-recommended preventive maintenance tasks and frequencies. Only 25% of utilities followed vendor recommendations. Although vendors informed utilities' initial maintenance programs, preventive maintenance tasks and frequencies are derived through local learnings via operating experience and manufacturer-specific reliability. There was no mention from any utility about supplementary tasks, in addition to scheduled preventive maintenance and overhauls, being performed to extend the life of these breakers.

Table 3-9
Maintenance Practices for In-Service Air Blast Circuit Breakers (4 Respondents)

Question	Utility 1	Utility 2	Utility 3	Utility 4
Do you have dedicated crews to do internal inspections/refurbishments?		X	X	
Do you have dedicated shops to maintain/overhaul these breakers?				
Do you have dedicated contractors to maintain/overhaul these breakers?			X	
Do you have reliable spare parts availability?				
Do you follow vendor recommended PM tasks and frequencies?			X	
Do you have additional tasks to extend the life of these breakers in addition to scheduled PMs and breaker overhaul?				

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CONCLUSIONS

Based on the survey results, the utility experience with air blast circuit breakers is that these types of breakers are “more” to “much more costly/difficult” on which to perform both minor and major maintenance and are “less” to “much less reliable” when compared to single pressure gas breakers. A review of planned replacements showed that the principal drivers behind programmatic replacement were operation and maintenance costs and an unacceptable level of reliability/availability

The population of air blast circuit breakers for utilities has been reduced by two-thirds over the last decade with no new air blast circuit breakers being installed. Also, nearly three-quarters of these types of breakers that are currently installed are over 40 years of age. The aging population of installed air blast circuit breakers creates difficulty and high costs in maintaining system reliability. The lack of available spare parts to properly maintain these types of breakers has become problematic for utilities due to the age of the technology.

Utilities have diminished abilities to properly maintain air blast circuit breakers. Few utilities have dedicated crews to perform internal inspections/refurbishments or dedicated shops and/or dedicated contractors to maintain/overhaul air blast circuit breakers.

The higher cost/difficulty associated with maintenance requirements when compared to newer technology, the unavailability of spare parts due to obsolescence, and the lack of dedicated crews to work on the ever-aging population of installed air blast circuit breakers may lead to longer outage times associated with both routine and emergency maintenance. This could become problematic for utilities and customers on both a cost and service-reliability perspective.

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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

Review of Utilities' Management of Oil Circuit Breakers

Current Industry Practices

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Technical Update, April 2018

EPRI Project Manager
B. Desai

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The following organization(s), under contract to the Electric Power Research Institute (EPRI), prepared this report:

Electric Power Research Institute (EPRI)
1300 West W.T. Harris Blvd.
Charlotte, NC 28262

Principal Investigators
B. Desai
Walter Barfield III

Coplanar Consulting, LLC
Yardley, PA 19067

Principal Investigator
M. Lebow

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ABSTRACT

This report presents the findings of a recent web survey conducted by EPRI on oil circuit breaker (OCB) asset management practices and concerns.

High voltage OCBs are an older technology that relies on complex mechanical systems for operation and large amounts of oil for insulation. OCB technology has generally performed well over decades of service. However, due to their age and environmental concerns about oil, OCBs may be considered less desirable technology. Moreover, because OCBs are an older technology, spare parts and mechanics experienced in their maintenance are not always readily available. For these reasons, many utilities have decided to reduce the size of their OCB fleets. Other utilities are considering such actions but may be restricted by various constraints. The survey was conducted to collect industry experience and industry plans for oil circuit breakers with the following objectives:

- Assess industry attitudes on retaining in-service oil circuit breakers
- Understand how peer companies are responding to OCB operations and maintenance challenges

Keywords

Oil Circuit Breakers

Asset Management

Industry Practices

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INTRODUCTION

This report presents the findings of a recent web survey conducted by EPRI on oil circuit breaker (OCB) asset management practices and concerns.

High voltage OCBs are an older technology that relies on complex mechanical systems for operation and large amounts of oil for insulation. OCB technology has generally performed well over decades of service. However, due to their age and environmental concerns about oil, OCBs may be considered a less desirable technology. Moreover, because OCBs are an older technology, spare parts and mechanics experienced in their maintenance are not always readily available. For these reasons, many utilities have decided to reduce the size of their OCB fleets. Other utilities are considering such actions but may be restricted by various constraints.

The survey was conducted to collect industry experience and industry plans for oil circuit breakers with the following objectives:

- Assess industry attitudes on retaining in-service oil circuit breakers
- Understand how peer companies are responding to OCB operations and maintenance challenges

Report Organization

In addition to this Introduction, the report includes the following chapters:

Chapter 2: Oil Circuit Breaker Designs

Chapter 3: Oil Circuit Breaker Survey Findings

Chapter 4: Conclusions

2
OIL CIRCUIT BREAKER DESIGNS

Description

Historically, bulk oil circuit breakers have been commonly used at voltages up to 230 kV, and on some systems, up to 345 kV. For lower ratings, up to 69 kV, oil circuit breakers often have all three phases housed in a single tank; the higher-rated units described here have three tanks, a single tank for each pole or phase.

Minimum-oil (also termed small oil volume) circuit breakers have been used at voltages up to the higher levels of transmission voltages, but because they have some application limitations, they are mainly applied to under 170 kV. They were extensively developed during the 1960s as an alternative to the bulk oil type, with its large oil volume, and the air-blast, with its need for expensive compressed air plant. They also competed with the then-new technology of the two-pressure SF6 types. Although widely used at 170 kV and below, many were found to be unreliable in service, particularly when switching capacitive currents. Those designs that are sound have given good service, and refurbishment programs exist.

Interruption Function (Bulk Oil)

As with all circuit breakers, the interrupter is a critical part of the oil circuit breaker. The most common method of interruption used in oil circuit breakers is called by several names, such as crossblast or oil blast interrupter. In these designs, the arc is drawn in front of a series of lateral vents, often called the grid assembly. The heat of the arc vaporizes the oil in the assembly, and the gases (mainly hydrogen) form a bubble that increases the pressure against the arc, finally forcing it to be blown into the grid vents. When the pressure inside the interrupter becomes sufficiently high and the length of the arc is adequately extended at current zero, the arc is extinguished.

The arc is always confined inside a bubble of gas formed from the oil, and this bubble extends and expands through the grid vents and the surrounding shell vents to the outside of the two or more interrupter assemblies in each pole (phase). The hot gases emerging from the vents are initially still ionized. It is essential to ensure, by correct grid design, that dielectric breakdowns do not occur between the outer vents of the shell system, external to the interrupter assemblies. Preventing dielectric breakdowns is particularly important for higher voltage interrupters in which multiple series grid arrangements are used. It is equally important that the shell vents in the same pole (phase) tank face away from each other. At the time the arc is being extinguished, fresh oil is drawn into the interrupter grid assembly to replace the arc-affected oil, thus cooling the arc zone and restoring the dielectric integrity of the system.

Interruption Function (*Minimum-Oil (Small Oil Volume)*)

The principle of interruption is that of an oil pump forcing clean oil into the interrupter to quench the arc. The used oil is retained within the interrupter zone, limiting the number of the short circuit clearances that are possible before oil maintenance or overhaul is required.

The arc is quenched in a similar manner to that of the bulk oil design, but in this case, the cool oil is forced into the arcing chamber by a pumping action derived from the opening movement of the contact drive shaft.

The interrupter is housed inside a porcelain enclosure as a live tank design, usually as a single vertical arrangement per pole (phase) on top of the mechanism. In some cases, the supporting insulator column is replaced by a current transformer.

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OIL CIRCUIT BREAKER SURVEY FINDINGS

EPRI developed a web-based survey to gather information about current utility thoughts regarding maintaining OCB fleets and recent past actions regarding retiring OCBs. Several US utilities known to have or to recently have had OCBs in service were invited to participate.

Fleet Characteristics – Installed Population

Based on the responses from the utilities surveyed, Table 3-1 and Table 3-2 show the counts for installed Oil circuit breakers by Voltage and by Voltage and Age, respectively. The count of Oil circuit breakers currently installed is 11,215 in the responding utilities' fleets. Of that installed population with known ages, 92.9% are greater than 30 years of age with 84.3% being greater than 40 years of age.

Table 3-1
Count of Installed Oil Circuit Breakers by Voltage (6 Respondents)

	Voltages (kV)			
	< 69	**69 to 138**	**138 to 230**	**> 230**
Count	8747	1287	1031	150

Table 3-2
Count of Installed Oil Circuit Breakers by Age and Voltage (6 Respondents)

Age (Yrs)	Voltages (kV)			
	< 69	**69 to 138**	**138 to 230**	**> 230**
< 30	653	28	65	1
30 to 40	651	112	141	1
40 to 50	1697	388	533	114
>50	5040	759	287	34
Unknown	706	0	5	0

Fleet Characteristics – Replaced Population

Table 3-3 shows the number of oil circuit breakers replaced in the last ten years. The principal motivations for replacement of those breakers is shown in Table 3-4. By summing the 11,215 installed breakers in Table 3-1 and 2,410 replaced breakers in Table 3-3, the count of installed oil circuit breakers ten years ago was 13,625. Over the last decade, this represents a 17.7% reduction in the number of oil circuit breakers installed in the utility fleets with all of the utilities having performed programmatic replacements of these types of breakers. For below 138 kV, Table 3-5 shows that the drivers for programmatic replacements by utilities were unacceptable reliability/availability and insufficient ratings. For above 138 kV, Table 3-5 shows that the drivers for programmatic replacements by utilities were excessive costs, environmental, and other. In Table 3-6, utilities were asked to select the rationale for not performing programmatic replacement on oil circuit breakers. Respondents selected acceptable performance of oil circuit breakers and unavailability of capital for not performing programmatic replacement.

Table 3-3
Count of Replaced Oil Circuit Breakers by Voltage (6 Respondents)

	Voltages (kV)			
	<69	**69 to 138**	**138 to 230**	**>230**
Count	1108	1160	142	0

Table 3-4
Principal Motivation for Replacement of Oil Circuit Breakers by Voltage (6 Respondents)

Principal Reason Replaced	Voltages (kV)			
	<69	**69 to 138**	**138 to 230**	**>230**
Programmatic Replacement	2	2	3	1
Individual Condition/Reliability	3	3	1	
Insufficient Rating		1		
Environmental				
Other				

Table 3-5
Driver for Programmatic Replacement of Oil Circuit Breakers (5 Respondents)

Programmatic Replacement	Voltages (kV)			
	<69	**69 to 138**	**138 to 230**	**>230**
Unacceptable Reliability/Availability	4	2		
Excessive Costs			1	1
Insufficient Rating		2		
Environmental			1	
Other			1	

Table 3-6
Rationale for No Programmatic Replacement of Oil Circuit Breakers (4 Respondents)

Rationale for No Programmatic Replacement	Voltages (kV)			
	<69	**69 to 138**	**138 to 230**	**>230**
Acceptable Performance	2	3	1	
Capital Unavailability	1	1	1	
Outage Unavailability				
Other				

Utility Experience

For this study, utilities were asked to rate their experience with oil circuit breakers with respect to single pressure gas breakers. The three categories for rating utility experience were reliability and maintenance practices, cost/difficulty of performing minor maintenance, and cost/difficulty of performing major maintenance. The following subsections detail the gathered responses for each utility.

Reliability and Maintenance Practices

Table 3-7 shows that three of the five utilities surveyed found that oil circuit breakers are less reliable than single pressure gas breakers while one of the five utilities found them to have similar reliability. One out of the five utilities responded that oil circuit breakers are more reliable than single pressure gas breakers.

Table 3-7
Reliability of Oil Circuit Breakers to Single Pressure Gas Breakers (5 Respondents)

Option	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Much Less Reliable						
Less Reliable	X			X		X
Same					X	
More Reliable		X				
Much More Reliable						

Cost/Difficulty of Performing Minor Maintenance

Table 3-8 shows that two of the six utilities surveyed found that oil circuit breakers are more costly/difficult to perform minor maintenance than single pressure gas breakers while three of the six utilities found them to be of similar cost/difficulty. One out of the six utilities responded that oil circuit breakers are less costly/difficulty than single pressure gas breakers.

Table 3-8
Cost/Difficulty of Performing Minor Maintenance of Oil Circuit Breakers Compared to Single Pressure Gas Breakers (6 Respondents)

Option	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Much More Costly/Difficult						
More Costly/Difficult	X			X		
Same		X	X			X
Less Costly/Difficult					X	
Much Less Costly/Difficult						

Cost/Difficulty of Performing Major Maintenance

Table 3-9 shows that two of the six utilities surveyed found that oil circuit breakers are more costly/difficult to perform major maintenance than single pressure gas breakers while four of the six utilities found them to be of similar cost/difficulty.

Table 3-9
Cost/Difficulty of Performing Major Maintenance of Oil Circuit Breakers Compared to Single Pressure Gas Breakers (6 Respondents)

Option	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Much More Costly/Difficult						
More Costly/Difficult			X	X		
Same	X	X			X	X
Less Costly/Difficult						
Much Less Costly/Difficult						

Current Maintenance Practices

Utilities were asked several questions on current maintenance practices of in-service oil circuit breakers. The responses for each utility by question are shown in Table 3-10. Free form comments for each of these questions can be found in Table 3-11.

Only 33.3% of the utilities surveyed have dedicated crews to perform internal inspections/refurbishments on oil circuit breakers. None of the utilities have dedicated shops to maintain/overhaul oil circuit breakers and none have dedicated contractors to maintain/overhaul these breakers. 66.6% of the utilities have a reliable source of available spare parts.

Utilities were asked if they followed vendor-recommended preventive maintenance tasks and frequencies. 50% of utilities followed vendor recommendations. Although vendors informed utilities' initial maintenance programs, preventive maintenance tasks and frequencies are derived through local learnings via operating experience and manufacturer-specific reliability. One of the six utilities mentioned they perform supplementary tasks, in addition to scheduled preventive maintenance and overhauls, at critical locations to extend the life of oil circuit breakers.

Table 3-10
Maintenance Practices for In-Service Oil Circuit Breakers (6 Respondents)

Question	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Do you have dedicated crews to do internal inspections/refurbishments?	✗	✗	✗	✗	✓	✓
Do you have dedicated shops to maintain/overhaul these breakers?	✗	✗	✗	✗	✗	✗
Do you have dedicated contractors to maintain/overhaul these breakers?	✗	✗	✗	✗	✗	✗
Do you have reliable spare parts availability?	✗	✓	✓	✗	✓	✓
Do you follow vendor recommended PM tasks and frequencies?	✗	✗	✓	✓	✓	✗
Do you have additional tasks to extend the life of these breakers in addition to scheduled PMs and breaker overhaul?	✗	✗	✗	✓	✗	✗

Table 3-11
Maintenance Practices Comments for In-Service Oil Circuit Breakers (6 Respondents)

Question	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Do you have dedicated crews to do internal inspections/refurbishments?						Our in-house crews are familiar with OCBs
Do you have dedicated shops to maintain/overhaul these breakers?						
Do you have dedicated contractors to maintain/overhaul these breakers?						
Do you have reliable spare parts availability?	Parts availability, especially for mechanisms, is a major factor in determining future serviceability. Some parts are beyond another rebuild cycle for some equipment.	We have found 3rd party vendors that have proven to be reliable for us.		Parts are obtained through various sources, but it's difficult to maintain these parts on hand and supplier availability is diminishing		For Most
Do you follow vendor recommended PM tasks and frequencies?	We view vendor recommendations as a guide only.	Our intervals are longer, but tasks are close to vendor specified tasks.				
Do you have additional tasks to extend the life of these breakers in addition to scheduled PMs and breaker overhaul?	Used to do Breaker Oil Analysis but found it to be of little worth.			At critical locations, some maintenance tasks are enhanced and additional tasks are added.		

4
CONCLUSIONS

Based on the survey results, the utility experience with oil circuit breakers is that these types of breakers are somewhat "more costly/difficult" on which to perform both minor and major maintenance and are somewhat "less reliable" when compared to single pressure gas breakers. A review of planned replacements showed that the principal drivers behind programmatic replacement are unacceptable reliability/availability and insufficient ratings for below 138 kV and excessive costs, environmental, and other for above 138 kV.

The population of oil circuit breakers for utilities has been reduced by approximately 18% over the last decade. Also, nearly 85% of oil circuit breakers that are currently installed are over 40 years of age. The aging population of installed oil circuit breakers may create difficulty and higher costs in maintaining system reliability.

Utilities have diminished abilities to properly maintain oil circuit breakers. None of the utility respondents have dedicated crews to perform internal inspections/refurbishments or dedicated shops and/or dedicated contractors to maintain/overhaul oil circuit breakers.

The higher cost/difficulty associated with maintenance requirements when compared to newer technology and the lack of dedicated crews to work on the ever-aging population of installed oil circuit breakers may lead to longer outage times associated with both routine and emergency maintenance. This could become problematic for utilities and customers on both a cost and service-reliability perspective.

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Degradation Rates of Steel Tower Coating Systems

Atmospheric Corrosivity Model Development

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EPRI Project Manager

N. Murray

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Principal Investigator
F. Moser

F. Besnard

N. Murray

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ABSTRACT

Transmission structure populations are aging and many of the barrier coatings that have been applied or repaired now require additional maintenance. Wholesale application of coating systems on the entire structure population becomes cost prohibitive and methods to screen the system for maintenance items becomes critical.

This report outlines a new and novel method of screening a transmission line system for structures with a high probability of coating degradation. In addition to coating degradation the consequences of doing nothing are now made apparent by understanding the corrosion rates of the structure itself. Application of the galvanizing and steel degradation data then allows an asset management team to forecast and schedule painting or repair operations based upon present condition models.

Keywords
Corrosion, Atmospheric Models, Galvanizing

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1 BACKGROUND, OBJECTIVES AND RESEARCH APPROACH

A coating program for overhead transmission towers can be costly and difficult to justify when the utility has thousands of structures in first cycle of a coating program. It is then important to understand the environment and how the structures age within those location such that the most aggressive conditions may be targeted first. Once the circuits have been prioritized by age and environmental factors, budgets may be established and work orders assigned for coating or structural repair.

Gaps and Objectives

The objective of this project is to provide accurate information so that condition assessments may be estimated for each circuit based upon the environment. Categorizing the Ontario province by corrosivity level has been completed by measuring corrosion rates of the galvanizing and the structure through field surveys and test coupons. This results in a database that may be queried to find structures with various levels of coating integrity and corrosion damage.

Research Approach

The research approach for this project is to incorporate the structure condition assessments from four past surveys and cross reference that data with coupons that have been in atmospheric exposure for the last three years. These data sources will then allow generation of models for asset management teams to select circuits for painting operations and repairs.

2 MONITORING ATMOSPHERIC CORROSION RATES USING TEST COUPONS

Test Coupon Fabrication and Installation

Mass loss calculations may be completed using test coupons exposed to an environment for some time interval. This mass loss may then be converted into corrosion rates with a high level of confidence in accuracy.

One hundred (100) racks were fabricated for subsequent attachment to specific towers at various heights, each rack holding thirteen (13) coupons in alignment with the compass rose. The rack was designed to hold four different types of coupons which would quantify degradation in various environments (Figure 2-1).

Figure 2-1: Coupon Rack Design for Attachment to the Structure

Bare Steel Coupons

The first type of coupon is a bare steel coupon that was cut from tower members removed from service (see Figure 2-2). This coupon will provide corrosion rates of the materials used in construction of the tower for each location throughout the province. A coupon may be removed at regular intervals and weighed for gravimetric analysis and mass loss conversions to corrosion rates.

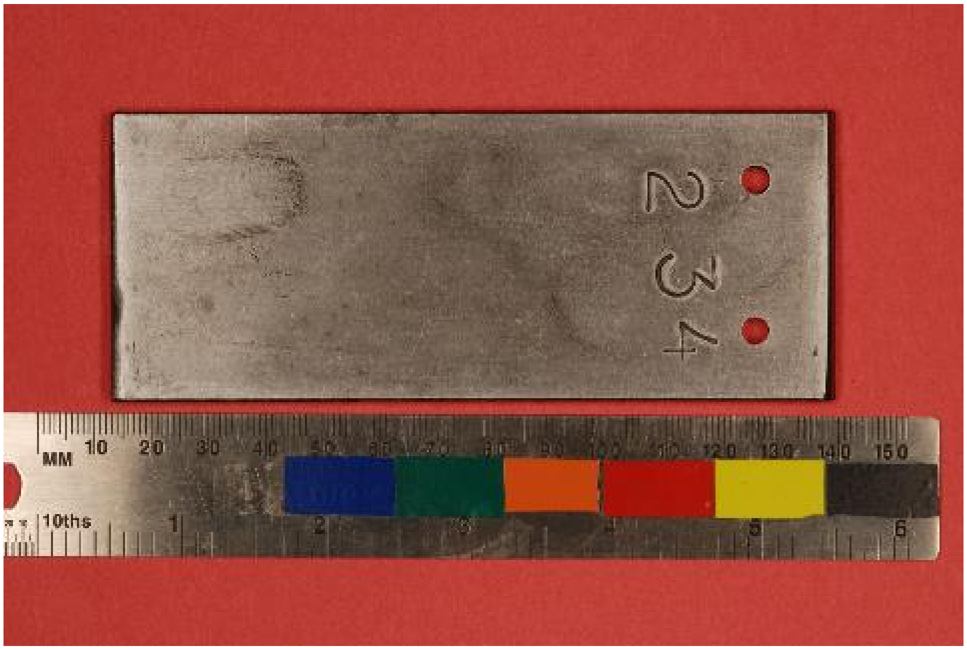

Figure 2-2: Bare Carbon Steel Coupon That Has Been Serialized, Weighed, Measured and Characterized by Color

Galvanized Coupons

The second type of coupon was also cut from tower members, blasted and hot dipped galvanized according to the ASTM A123 standard (see Figure 2-3). This coupon may also be examined at regular intervals using thickness measurements to determine galvanize (zinc) corrosion rates throughout the province.

Figure 2-3: Galvanized Test Coupon That Has Been Serialized, Weighed, Measured and Characterized by Color

Coating System Coupons

The third coupon was cut from tower members, degreased and spray painted with Galvotech (see Figure 2-4). Galvotech 2000 coating system is a high load zinc rich coating system with performance claims similar to hot dipped galvanize. The performance of this system may be summarized by attributes such as capacitance, permeability, moisture uptake, adhesion or thickness. The simplest method that may be employed to trend coating system degradation would be thickness measurements using ultrasonic or magnetic pull off gauges. This trending requires multiple inspections at specific time intervals and will support decisions on required time until recoat operations.

Figure 2-4: Coated Steel Coupon That Has Been Serialized, Weighed, Measured and Characterized by Color

Tensile Coupon

The last type of coupon is a tensile specimen that is designed to quantify the mass loss due to atmospheric exposure. This is completed by removing the specimen from the rack and pulling tension until failure while monitoring displacement and load. Unfortunately, this is a destructive test and will not allow trending but will frame the time interval required for pit formation and penetration rates for localized corrosion.

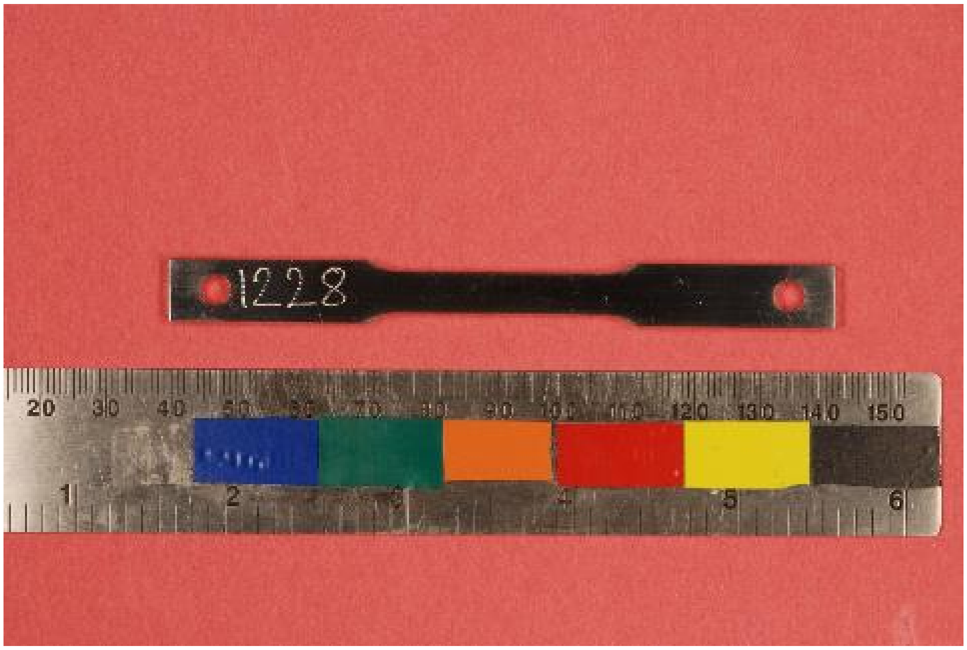

Figure 2-5: Tensile Test Steel Coupon That Has Been Serialized, Weighed, Measured and Characterized by Color

Listing of Coupon Measurements

Each coupon was characterized in the laboratory to provide a baseline condition assessment on thirteen hundred (1,300) test coupons with the following data types and equipment required.

- Surface Area
- Thickness
- Width
- Length
- Mass
- Coating System Layer Thickness
- Galvanizing Thickness
- Profile
- Photographs (with color correction using Hunter Scale)

Color Correction Baseline

The last item supporting the coupon characterization was a baseline of the color correction tabs within each coupon photograph. The Hunter Scale was selected for all color baselines using the combination of L*, a* and b*. This data may be used to understand the changes in the coupons and trend the effects of UV degradation. This could be completed within the laboratory environment using a spectrometer or by digital photography and spectral analysis. The following

Table 1 shows the baseline values of each color tab.

Table 1: Baseline Hunter Scale of the Color Correction Tabs

Reference Color	L*	a*	b*
Blue	15.040	0.107	-0.140
Green	17.720	-0.520	1.327
Orange	19.000	1.672	2.424
Red	17.970	2.127	1.138
Yellow	19.060	-1.950	5.984
Black	18.450	0.129	0.477

Coupon Rack Installation

Each coupon rack had a specific location and attachment height designated by HydroOne and all sites were above EPRI working heights so HydroOne personnel took ownership of all coupon installations (see Figure 2-6). The attachment was made using a pair of angles that were slotted to allow clamping to the horizontal member (see Figure 2-1).

Figure 2-6: Typical Coupon Rack Installation

The bare steel coupons and the tensile specimen were removed from service and returned to the EPRI Charlotte campus for characterization. The balance of coupons (Galvotech and Hot Dipped Galvanizing) will remain in service for an additional period of time.

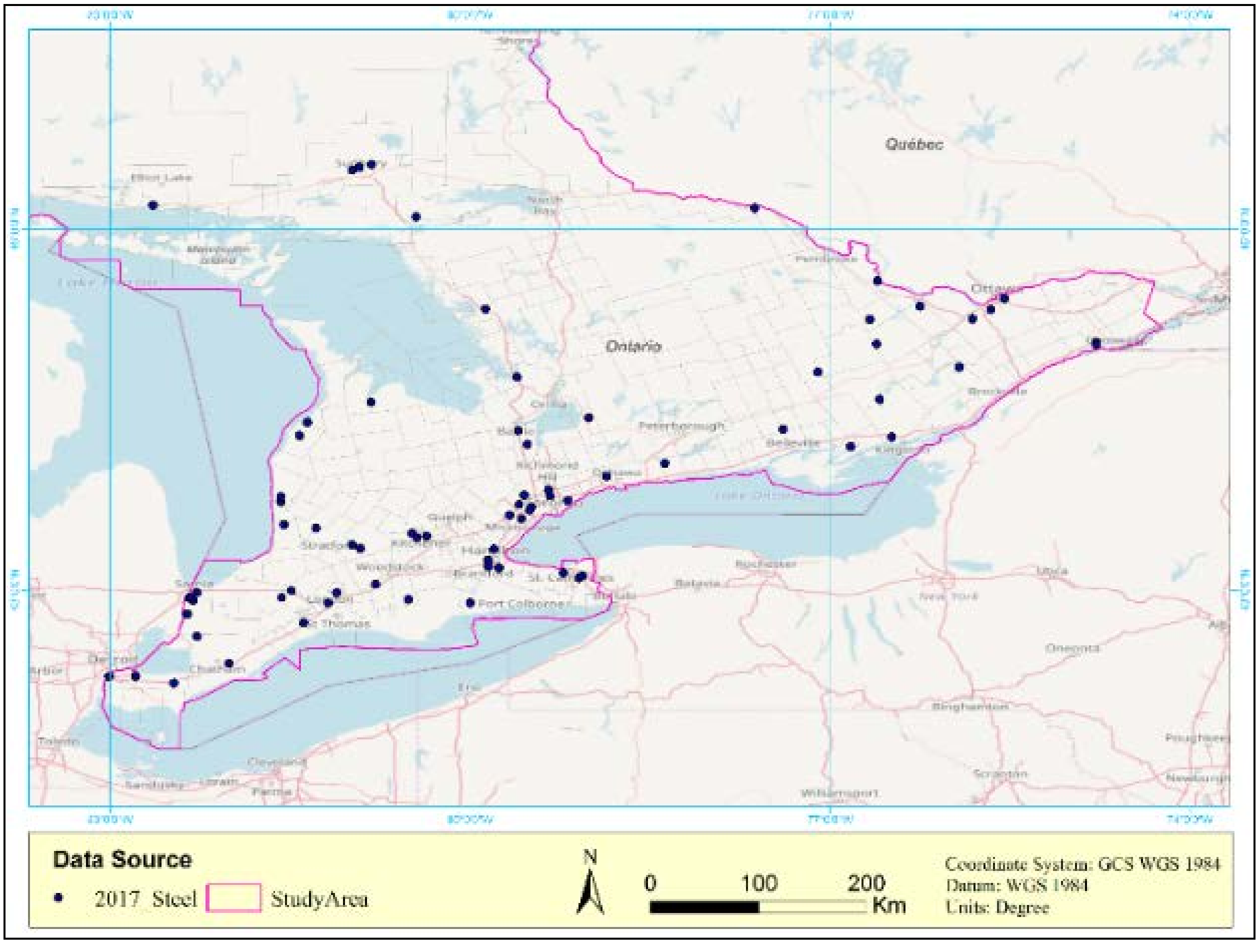

Figure 2-7 Structure Locations for Steel Coupon Data

Coupon Evaluations

Objective

The objective of this task is to measure the mass loss and thickness loss on 2 steel rectangle coupons from each coupon rack. This process will provide an average of each point on the compass rose. The tensile specimen will then be tested to determine residual strength and study the correlation with localized corrosion resulting in mass loss.

Collecting samples:

1. Unwrap the package
2. Record the following:
   a. Circuit #, Structure #, date, both rectangle #s and the tensile specimen #

Pictures:

1. Set the tensile specimen and plates, number side up on the photographic stand
2. Place the color guide next to it (see Figure 2-8)

3. On a post-it note, write clearly the circuit #, structure #, DB#s and R#
4. Take a picture
5. Flip the tensile specimen and rectangles
6. Take another picture
7. Put back the sample in the bag with the post-it note

**make a note if you see paint on the coupons*

Mass loss Measurement:

1. Make the NACE steel cleaning solution (500 ml HCL, 500 ml DI water, 3.5g hexamethyltetramine).
2. In a glass dish, pour steel cleaning solution
3. Place the steel coupon in the solution and wait approximately 3 minutes
4. Using acid resistant gloves, turn the coupon and wait 3 minutes
5. Take the coupon out of the solution, rinse it thoroughly with tap water and make sure all the rust is gone. If not, place the coupons for another 3 minutes.
6. Completely dry the coupon with paper towel or compressed air
7. Once dry, weigh the sample and record it.
8. Place the sample back into the bag
9. Repeat this procedure for the tensile specimen
10. Make thickness and width measurement in the smallest part of the tensile specimen.
11. perform tensile test on the tensile specimen (this test remains incomplete)

Figure 2-8 Image record for each coupon with color correction

Steel Coupon Analysis Results

100 coupon racks with coupons were to the environment for three (3) years and 300 coupons were returned to the EPRI campus for analysis. The rectangular coupons totaled 200 with 100 tensile specimens. 19 of the rectangular coupons were unusable due to paint applied during tower painting operations (see Figure 2-9).

Preliminary gravimetric analysis of the coupons results in the following graph of corrosion rates for steel and illustrates the structure site corrosivity classifications using the remaining 181 coupons for corrosion rate measurements (see Figure 2-10 and Table 2).

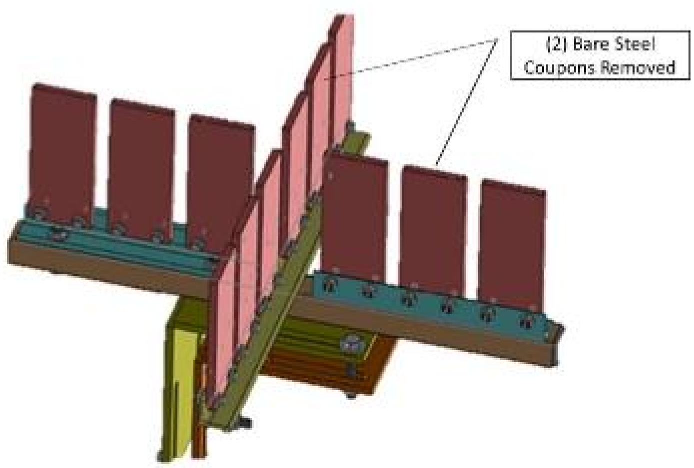

Figure 2-9 Two (2) Bare Steel Coupons Removed for Analysis

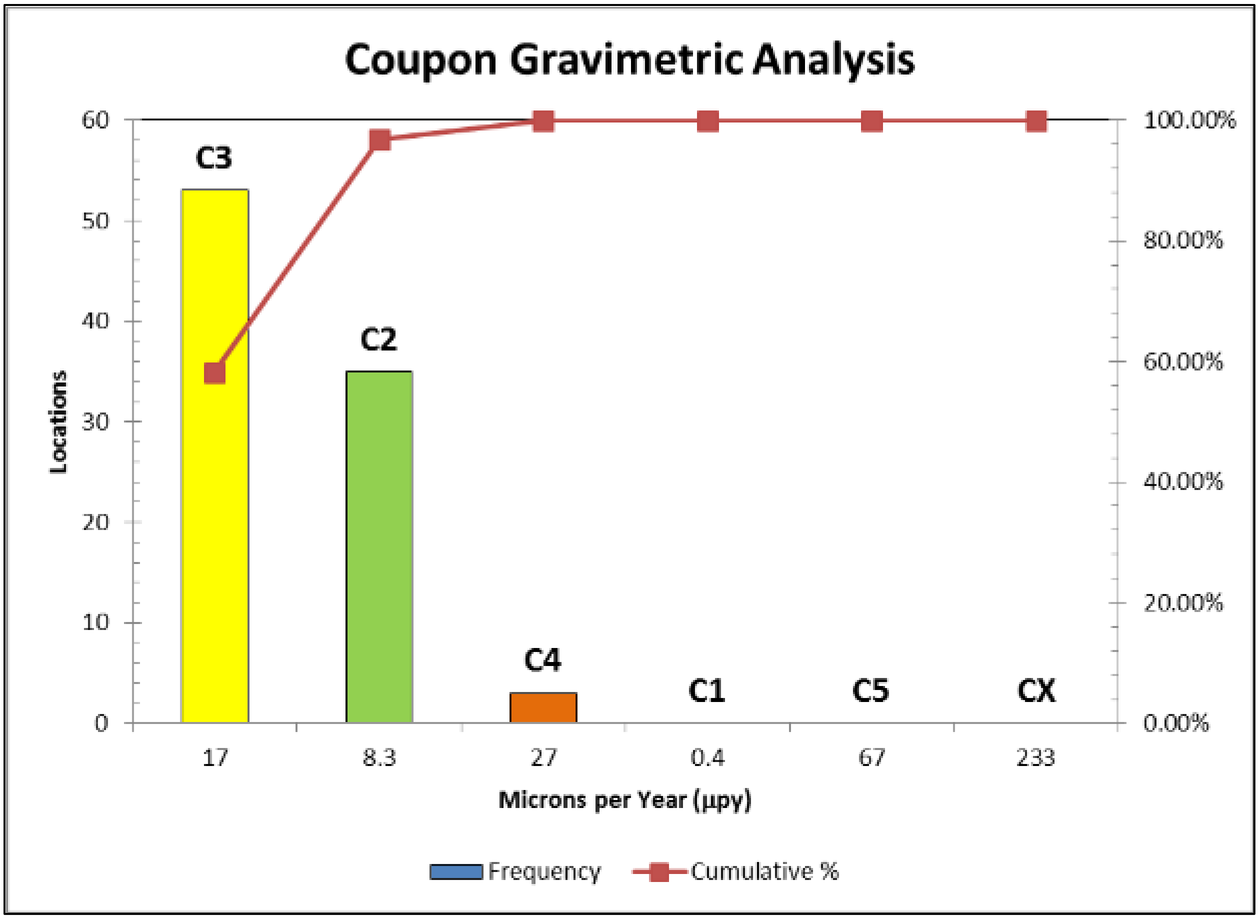

Figure 2-10 Results from gravimetric testing of steel coupons

Table 2 Cumulative percentages of each corrosivity classification

Classification	*Bin*	*Frequency*	*Cumulative %*	*Bin*	*Frequency*	*Cumulative %*
C1	0.4	0	0.00%	17	53	58.24%
C2	8.3	35	38.46%	8.3	35	96.70%
C3	17	53	96.70%	27	3	100.00%
C4	27	3	100.00%	0.4	0	100.00%
C5	67	0	100.00%	67	0	100.00%
CX	233	0	100.00%	233	0	100.00%

3 STRUCTURE CONDITION ASSESSMENTS – FIELD SURVEY 2017

Survey Background

One hundred transmission structures included in this survey were selected by the utility. They were chosen to cover HydroOne's territory that was not represented by the coupon racks in areas with ease of access. In preparation for the survey, accessibility to and general location of the structures were assessed in Google Earth. During this desk study period, adjustments were made to substitute some structures that were not conducive to a productive field survey (i.e. travel time, vegetation issues, etc.).

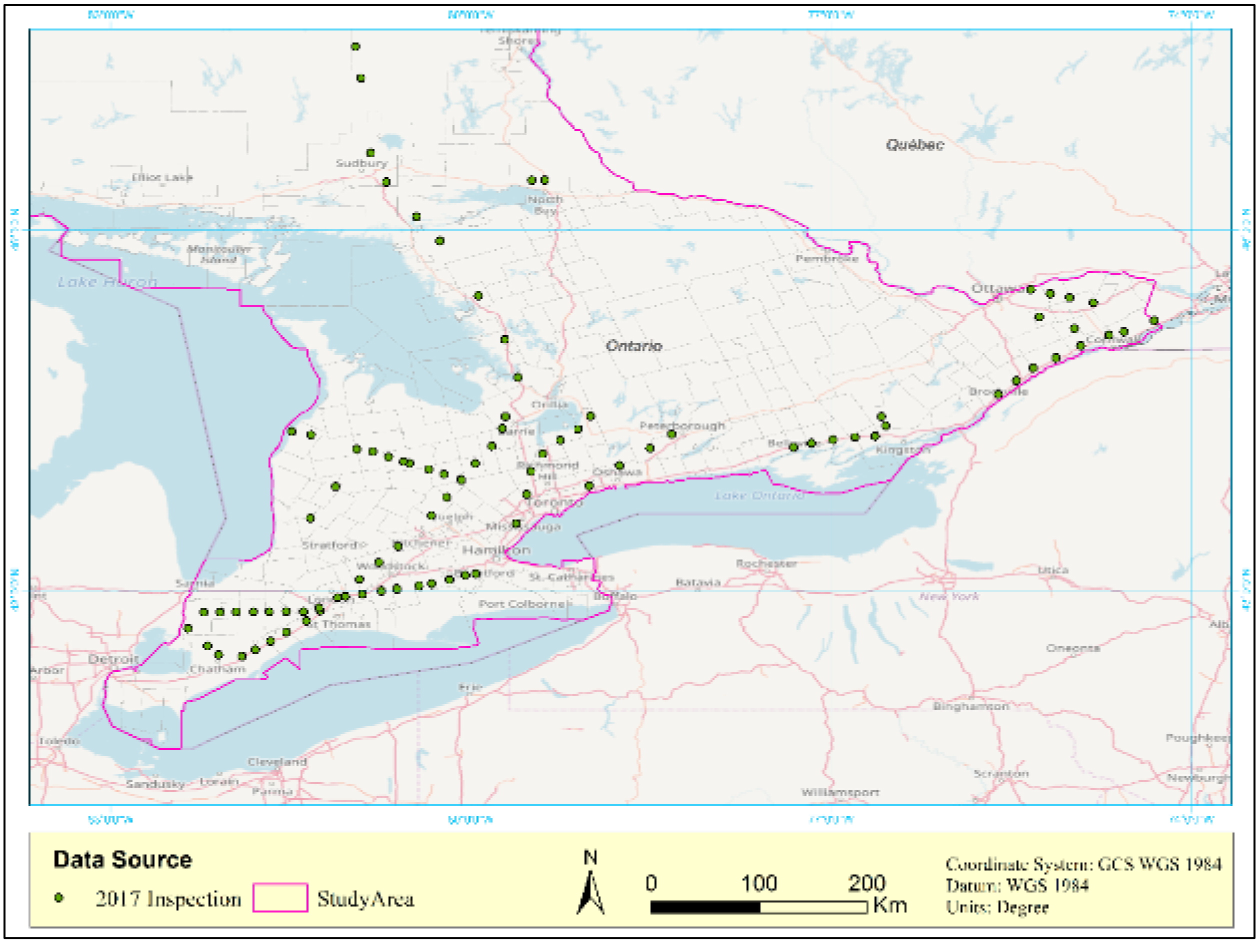

Figure 3-1 Structure Locations for 2017 Field Survey

Survey Procedure

The following field procedure was conducted at each selected HydroOne transmission structure:

1. Before beginning the survey, a safety check was conducted.
    a. It was necessary to check that all crew members were wearing appropriate PPE.

b. The structure was then observed from a safe distance to see if there were any overhead hazards, such as loose members.

c. Ground level was evaluated for safety – primarily tripping, wildlife, and vegetation hazards.

d. The structure was tested with a voltage detector to ensure it was not energized.

2. General observations were made about the location and structure itself. Observations recorded included:

   a. Structure type

   b. Foundation type

   c. Replacement members

   d. Substations/pipelines/cables

   e. Mechanical damage.

3. For each accessible structure member below six feet, the following were collected:

   a. Width and thickness of member.

   b. General observations of the member

      i. mechanical damage

      ii. presence of coating

      iii. localized corrosion.

   c. Three galvanizing or coating thicknesses, collected and averaged using a DeFelsko PosiTector.

   d. If present, the thickness of a spangle area on the member to be used as a proxy for original galvanizing thickness.

   e. If present, a rusting classification using the SSPC-VIS 2: Standard Method of Evaluating Degree of Rusting on Painted Steel Surfaces visual guide.

   f. If present, a pitting classification using ASTM G46-94(2013): Standard Guide for Examination and Evaluation of Pitting Corrosion.

Survey Analysis Results

From the original in-service dates of the structures, their galvanizing thicknesses, and their spangle thicknesses, it was possible to calculate an average corrosion rate per structure. Based on the international standard ISO 9223: Corrosion of metals and alloys – Corrosivity of atmospheres – Classification, determination, and estimation, it was possible to assign each structure to a corrosivity category: C1 – C5. Figure 1 shows the distribution of the surveyed HydroOne structures, while Table 1 is a reference guide from ISO:9223 outlining the characteristics of the classes.

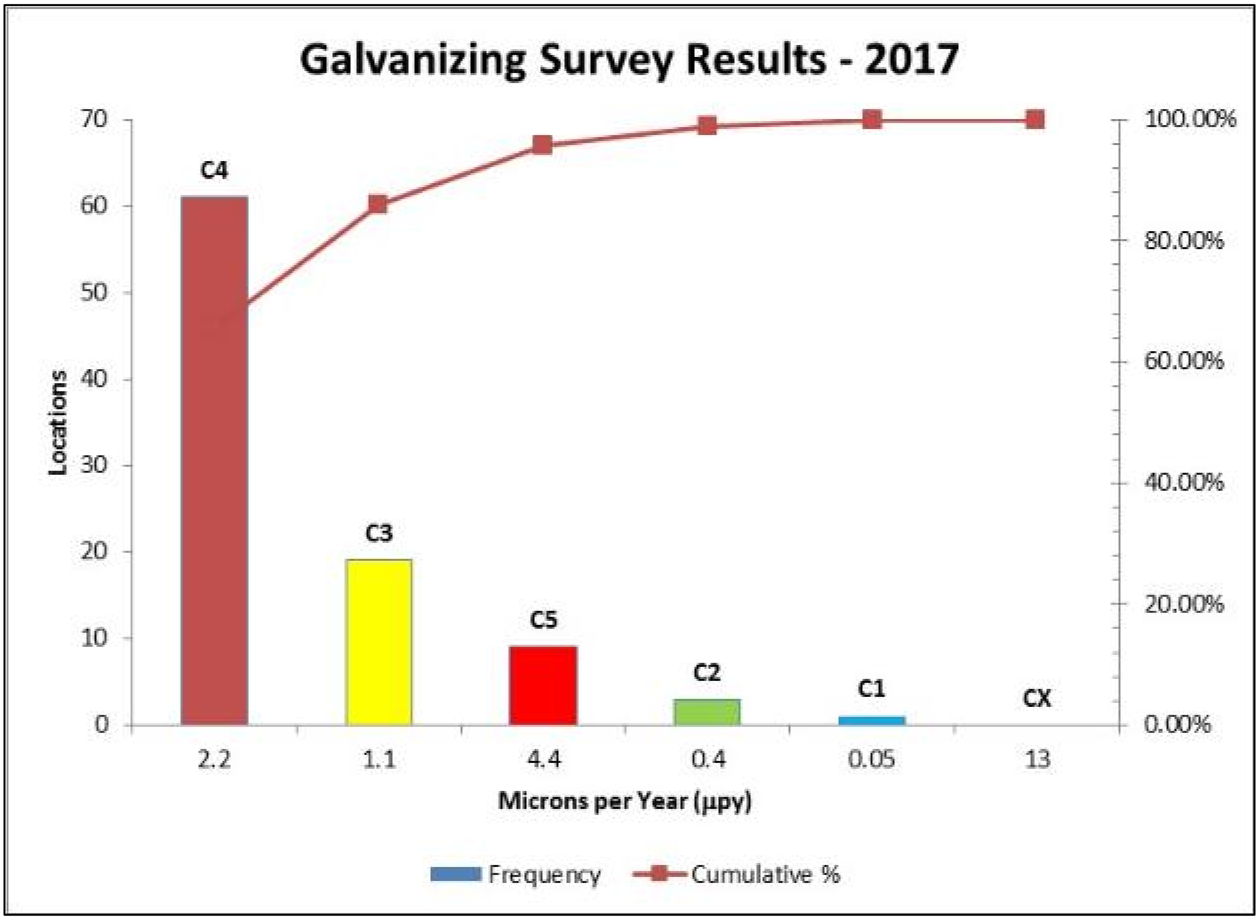

Figure 3-2: ISO 9223 Corrosion Categories for HydroOne Structure Survey (2017).

Table 3 Cumulative percentages of each corrosivity classification

Bin	*Frequency*	*Cumulative %*	*Bin*	*Frequency*	*Cumulative %*
0.05	1	1.08%	2.2	61	65.59%
0.4	3	4.30%	1.1	19	86.02%
1.1	19	24.73%	4.4	9	95.70%
2.2	61	90.32%	0.4	3	98.92%
4.4	9	100.00%	0.05	1	100.00%
13	0	100.00%	13	0	100.00%

Table 4: Description of typical atmospheric environments related to the estimation of corrosivity categories (ISO:9223:2012).

Corrosivity category[a]	Corrosivity	Typical environments — Examples[b]	
		Indoor	Outdoor
C1	Very low	Heated spaces with low relative humidity and insignificant pollution, e.g. offices, schools, museums	Dry or cold zone, atmospheric environment with very low pollution and time of wetness, e.g. certain deserts, Central Arctic/Antarctica
C2	Low	Unheated spaces with varying temperature and relative humidity. Low frequency of condensation and low pollution, e.g. storage, sport halls	Temperate zone, atmospheric environment with low pollution (SO_2 < 5 μg/m^3), e.g. rural areas, small towns Dry or cold zone, atmospheric environment with short time of wetness, e.g. deserts, subarctic areas
C3	Medium	Spaces with moderate frequency of condensation and moderate pollution from production process, e.g. food-processing plants, laundries, breweries, dairies	Temperate zone, atmospheric environment with medium pollution (SO_2: 5 μg/m^3 to 30 μg/m^3) or some effect of chlorides, e.g. urban areas, coastal areas with low deposition of chlorides Subtropical and tropical zone, atmosphere with low pollution
C4	High	Spaces with high frequency of condensation and high pollution from production process, e.g. industrial processing plants, swimming pools	Temperate zone, atmospheric environment with high pollution (SO_2: 30 μg/m^3 to 90 μg/m^3) or substantial effect of chlorides, e.g. polluted urban areas, industrial areas, coastal areas without spray of salt water or, exposure to strong effect of de-icing salts Subtropical and tropical zone, atmosphere with medium pollution
C5	Very high	Spaces with very high frequency of condensation and/or with high pollution from production process, e.g. mines, caverns for industrial purposes, unventilated sheds in subtropical and tropical zones	Temperate and subtropical zone, atmospheric environment with very high pollution (SO_2: 90 μg/m^3 to 250 μg/m^3) and/or significant effect of chlorides, e.g. industrial areas, coastal areas, sheltered positions on coastline

Overall, corrosion would vary by height and even by member – with general corrosion increasing with height and the small diagonal members being the most corroded members. However, there was no significant difference between corrosion rates on horizontal versus vertical faces (5.4% difference). When coating systems were already in place, all of the painted structures had poor paint coverage with holidays and general spalling of the coating systems – some with even entire members forgotten.

Generally, atmospheric corrosion rates were highest in the southwestern section of the province near Lake Huron and the Michigan border. There are C5 (very high) category structures in many of the surveyed circuits: B4V, B22D, D4W, L24L, L28C, M32W, P15C, P502X, W42L, X503E. However, the circuits with the highest average corrosion rates (> 2 microns/year) are included in Table 5. These circuits were not necessarily in the worst condition upon visual inspection, therefore full confidence cannot be placed in only in looking at these structures.

Table 5: Average atmospheric corrosion rates for circuits with greater than two microns lost per year.

Circuit	Avg Corrosion Rate (microns loss/year)
B22D	2.095958
B4V	2.16924
L24L	2.258941
L28C	2.189025
W42L	2.265625

Transmission lines may traverse areas of high and low corrosion rates, therefore use of this data requires an understanding of the age of the structure. If sufficient galvanizing is remaining despite the corrosivity level at that location, those structures may be monitored and trended.

4 MODEL GENERATION

Data Analysis

The data was analyzed from ninety-one (91) structures using the bare steel coupons and the galvanizing mass loss from the 2001, 2013 and 2017 field surveys totaling approximately 300 additional structures. The Ontario landmass was mapped to understand land cover (see Figure 4-1) and effects of elevation (see Figure 4-2). Additionally, the locations of generation plants were added for future Gaussian plume models to understand micro-climates (see Figure 4-3).

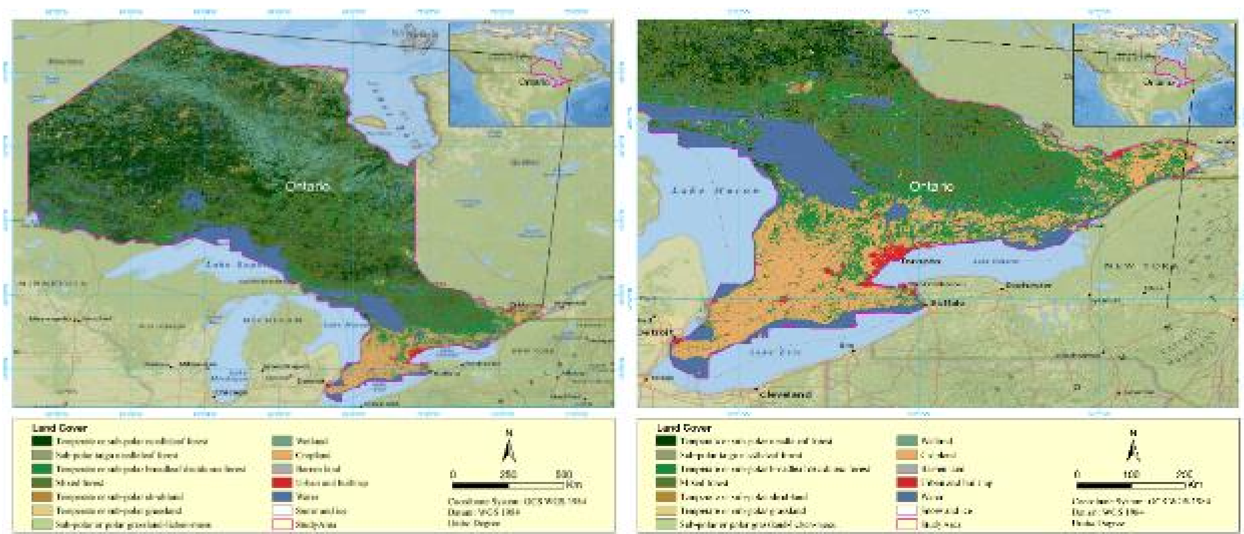

Figure 4-1 Land Cover Throughout the Ontario Province and Lower Ontario

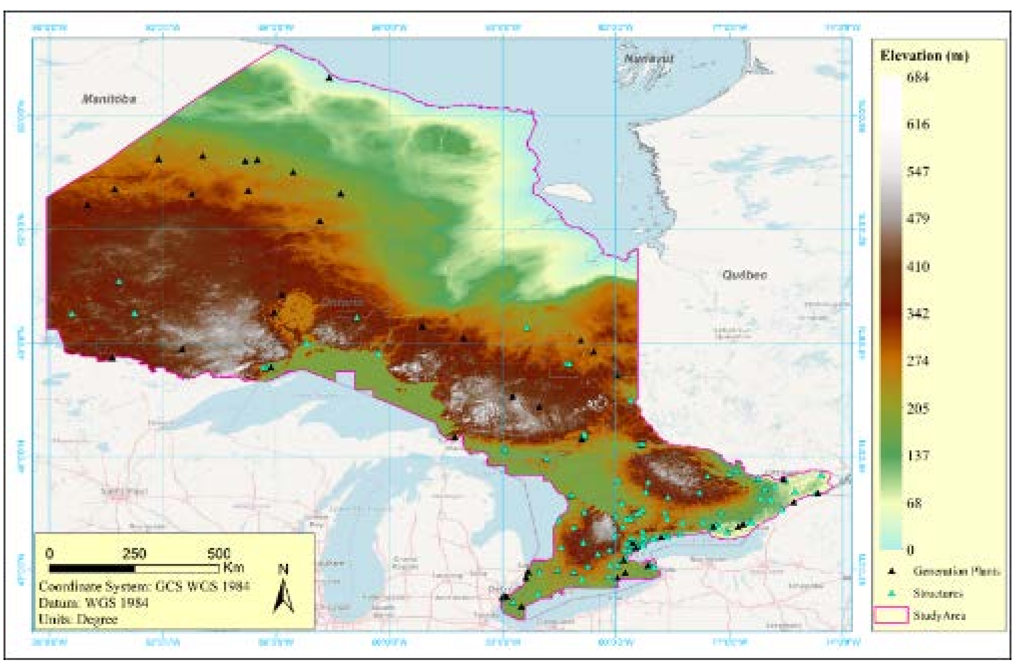

Figure 4-2 Elevation Map of Ontario

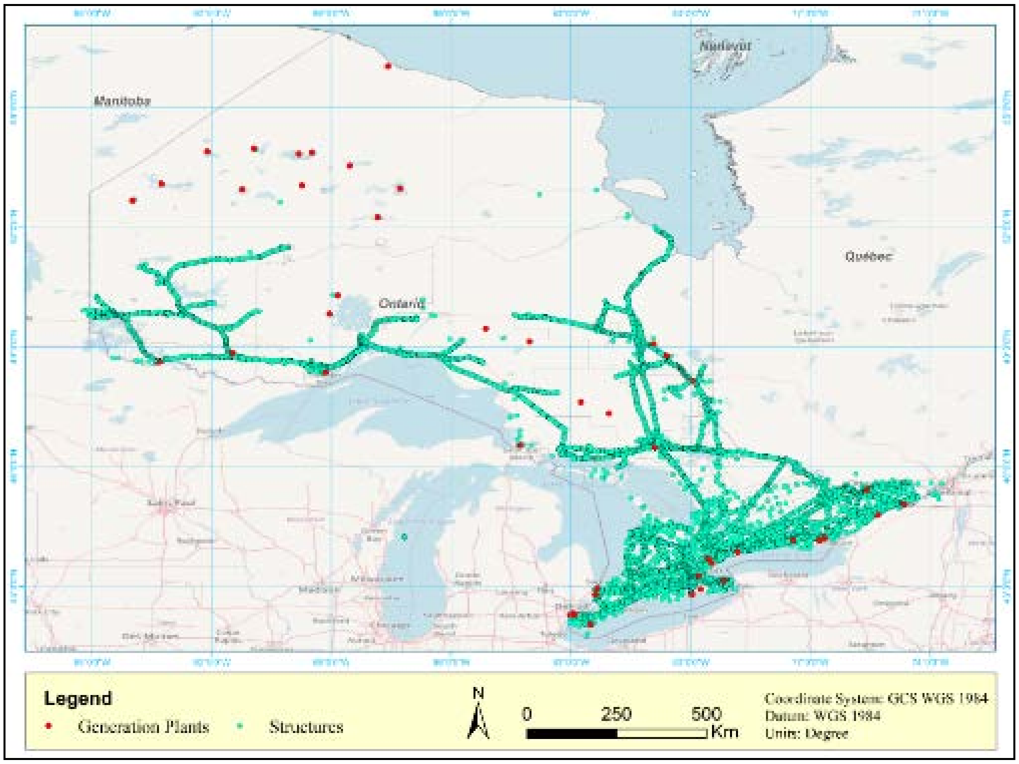

Figure 4-3 Illustrates HydroOne Structure and Generation Locations

A method for spatial interpolation was used to predict the unknown regions around structures with known corrosion rates. This was completed to understand how structures share an environment and statistically determine the effective distances that the environment may remain constant. As a result, it was decided that insufficient data was available to properly model the corrosivity levels above Sudbury.

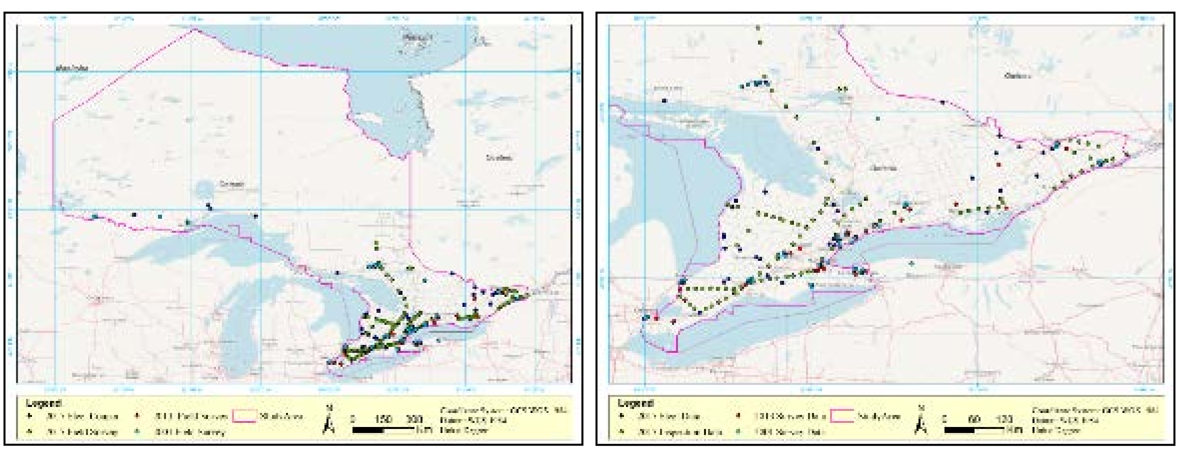

Figure 4-4 Structure Inspection Locations within Southern Ontario

Steel coupons were removed from service after three (3) years of aging in the field. Gravimetric methods were then used to measure corrosion rates based upon mass loss calculations in microns per year. Survey data for galvanizing loss was then analyzed and mapped for regional corrosivity levels.

Coupon vs Galvanizing Survey Comparisons

The 2017 steel coupons survey (see Figure 4-5) shows that a majority of the locations are categorized as “C3” (followed by a majority of “C2” and then “C4”), while the galvanized tower survey performed the same year shows that the majority of the locations are categorized as “C4” (followed by a majority of “C3” and then “C5”). These two surveys, performed the same year, show a disparity of an entire category. This “shift” of one category could be explained by the height at which the corrosion measurements were performed (see Table 6).

Table 6 Comparison of ISO 9223 Classifications for Zinc and Steel Corrosion Rates (μpy)

Metal Type	C1	C2	C3	C4	C5	CX
Galvanizing (zinc)[1]	≤ 0.05	0.05 to ≤ 0.4	0.4 to ≤ 1.1	1.1 to ≤ 2.2	2.2 to ≤ 4.4	4.4 to ≤ 13
Carbon Steel[2]	≤ 0.4	0.4 to ≤ 8.3	8.3 to ≤ 17	17 to ≤ 27	27 to ≤ 67	67 to ≤ 233

Notes:

1. *Zinc classifications are based upon 30-year corrosion rates*
2. *Carbon steel classifications are based upon 10-year corrosion rates*

In the case of the steel coupons, the coupons were placed, on average, at a height of 62 feet with some coupons placed as high as 121 feet, while the galvanized tower survey was performed at human height, resulting in corrosion rates measured at a maximum of 6 to 7 feet. Close to the ground, galvanized tower legs and other members were exposed to higher time of wetness due to vegetation, higher concentrations of chloride due to road salt, and potentially higher concentrations of nitrates due to fertilizer or pesticide broadcasting, resulting in higher corrosion rate than the steel placed higher on the tower.

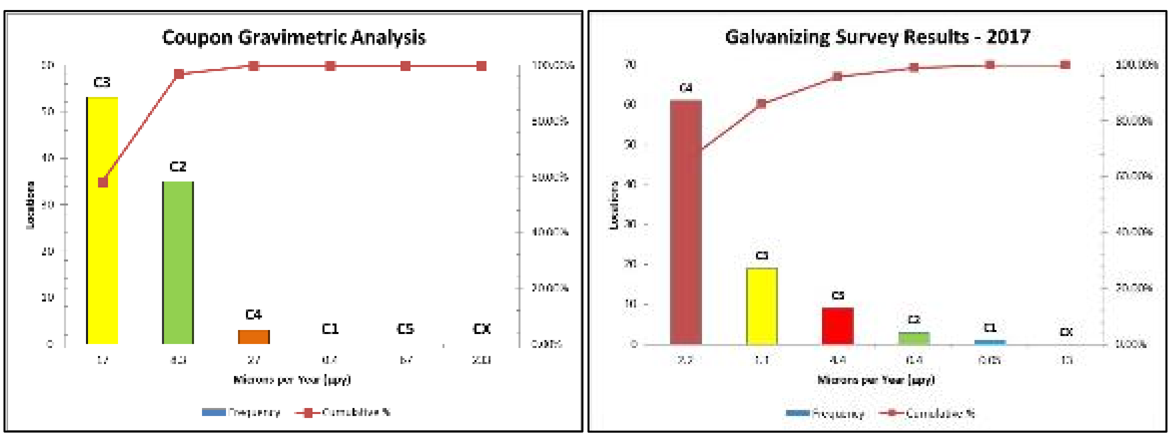

Figure 4-5 Corrosivity Distributions for Steel Categories vs Galvanizing Categories

Survey Comparisons

To understand the differences in the two data sets, the variables were defined and studied to determine if they resulted from differences in survey procedure, equipment used in the study, assumptions used in the analysis or the environment.

The first potential variable ruled out was the criteria for establishing the original galvanizing thickness for mass loss calculations. Distributions of remaining spangle were analyzed and a value of 7.6 mils (193 μ) was benchmarked for vertical member coating thickness.

The second variable ruled out was the instrumentation for the thickness measurements because the technologies were identical and within calibration.

The last variable in the study was the method of cleaning the structures. The structure surface cleaning method used in the 2001 survey used a wire brush with 25 strokes horizontally and 25 strokes vertically. The surveys in 2013 and 2017 used a twisted braided wire cup in an angle grinder for cleaning the surface.

Lab analysis on an aged galvanizing surface determined that the cleaning method had little effect on the thickness measurements (see Table 7). This is supported by the values for mean and standard deviation for each cleaning technique.

Table 7 Surface Cleaning Data Comparing Hand Tool and Power Tool Methods

		Wire brush			Angle Grinder		
		Procedure	**Galvanizing (mils)**	**Difference**	**Procedure**	**Galvanizing (mils)**	**Difference**
Base measurement	**Average**		3.62			3.7	
	St.Dev.		0.42			0.45	
1st cleaning	**Average**	25 strokes (side by side)	3.52	0.1	2 passes	**3.4**	**0.3**
	St.Dev.		0.33			**0.3**	
2nd cleaning	**Average**	25 more strokes (up and down)	**3.2**	**0.42**	12 passes	2.98	0.72
	St.Dev.		**0.23**			0.45	

These results led researchers to believe that the variance in corrosion rates with towers in close proximity may be due to Gaussian plume model effects or boundary layers due to topography but not a variance in survey methods.

Model Confidence Levels

Atmospheric models have been developed to forecast for zinc (galvanizing) and steel degradation rates based upon location within the lower Ontario province. Currently these models contain almost 383 structures with a resulting 4.19% margin of error at a 90% confidence level or 4.99% margin of error at a 95% confidence level. Use of this model then significantly lowers the probability of error in selection of structures for a painting or structural repair program.

A production rate of 1,500 structures with a per structure painting cost of $46,500 results in a yearly painting program of $69.75M with a structure selection error of $2.92M at 4.19 % error or $3.48M at 4.99% error.

5 CONCLUSIONS

Converging the galvanizing loss data from all three survey years resulted in a GIS based map that was categorized using the ISO 9223 atmospheric corrosivity levels (see Figure 5-1). Reviewing the category distributions (see Figure 4-5) it became apparent that southern Ontario has a significant number of locations falling within the C4 and C5 category for galvanizing coating loss.

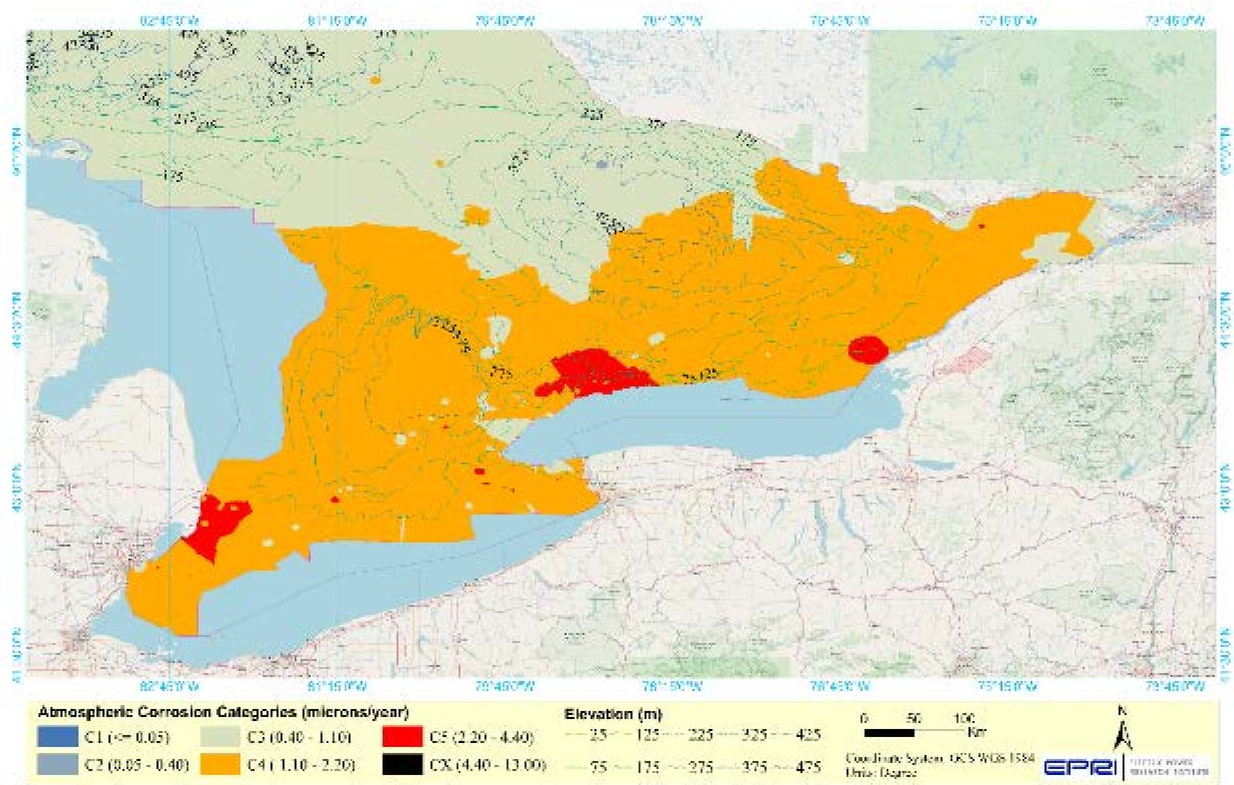

Figure 5-1 Interpolation Map for 2001, 2013 and 2017 Galvanizing Mass Loss (μpy) Surveys (C1 to CX)

Another series of maps were then developed based upon corrosion rate ranges depicting galvanize coating loss (see Figure 5-2). This was completed to allow an analyst more flexibility by defining corrosion rate ranges within each category.

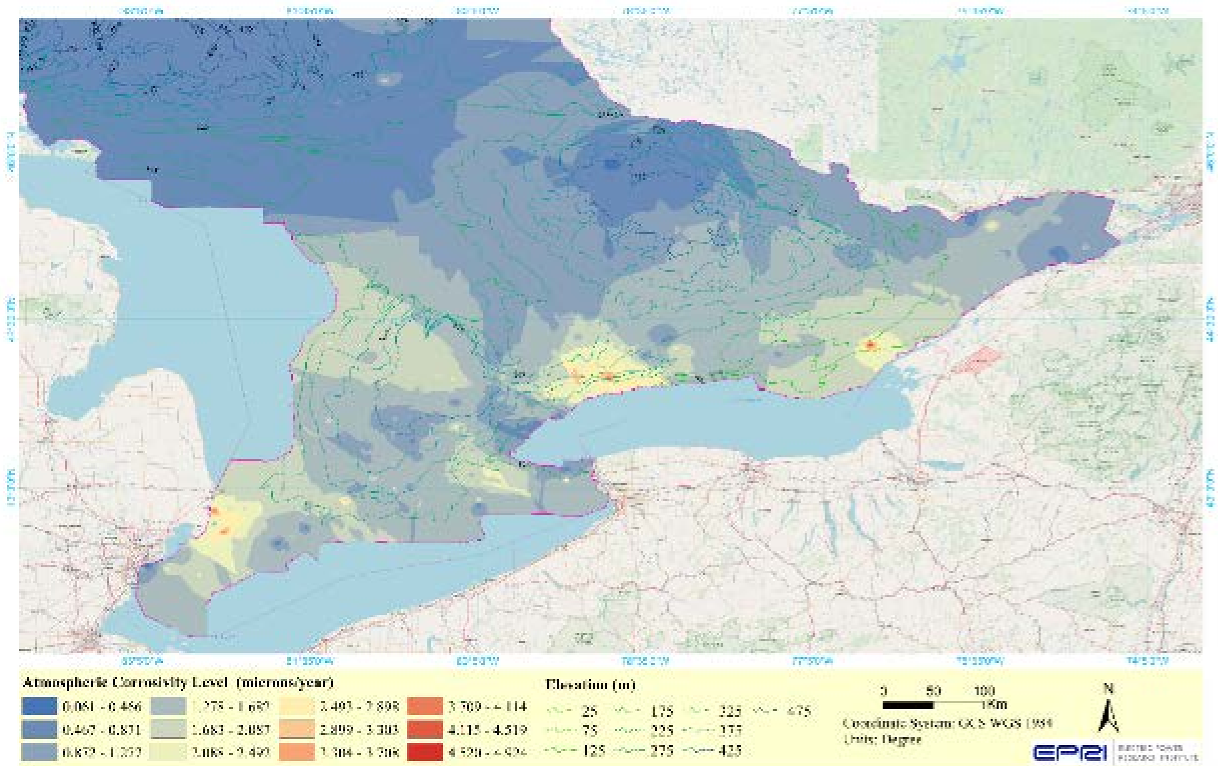

Figure 5-2 Interpolation Map for 2001, 2013 and 2017 Galvanizing Mass Loss Surveys (μpy)

Implementation of New Learning

The use of the galvanizing loss maps may allow a significant savings by targeting circuits with a large volume of structures in a very corrosive environment. With all programs it becomes important to understand levels of risk if that program is deferred and for how long. This may then be accomplished using the steel mass loss maps (see Figure 5-3 and Figure 5-4).

The consequences of delaying the coating program may be understood through the application of the steel corrosion rate map (see Figure 5-4) in an engineering case study to determine when that structure(s) is a reject. Before that calculation is valid the time to exposure must be determined using the condition assessments from the field surveys or modeled using the mass loss rates for the galvanizing.

New galvanizing thicknesses may be divided by the age of the structure to determine remaining galvanizing thickness or until the steel is exposed. Degradation rates of the steel may than be applied until that structure is considered at risk of failure. This would be modeled in a structural engineering case study to determine sectional losses and reject rates.

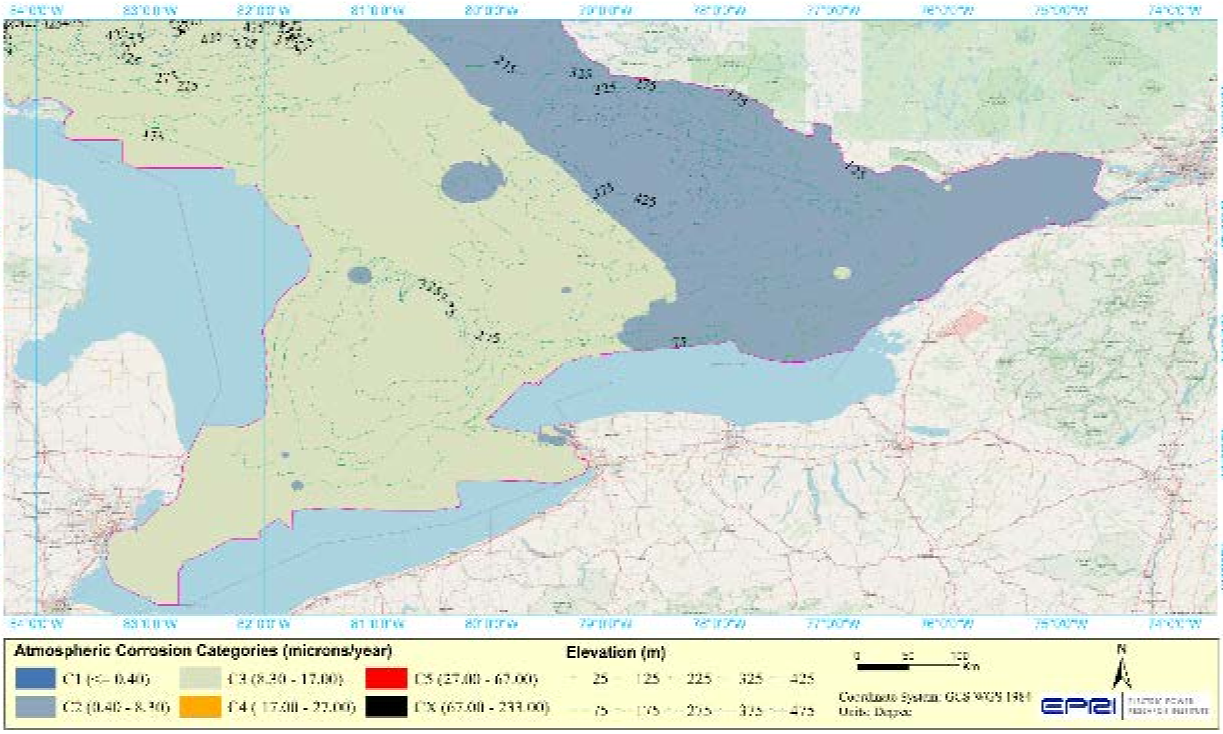

Figure 5-3 Atmospheric Corrosivity Map (μpy) for Steel Exposure (C1 to CX)

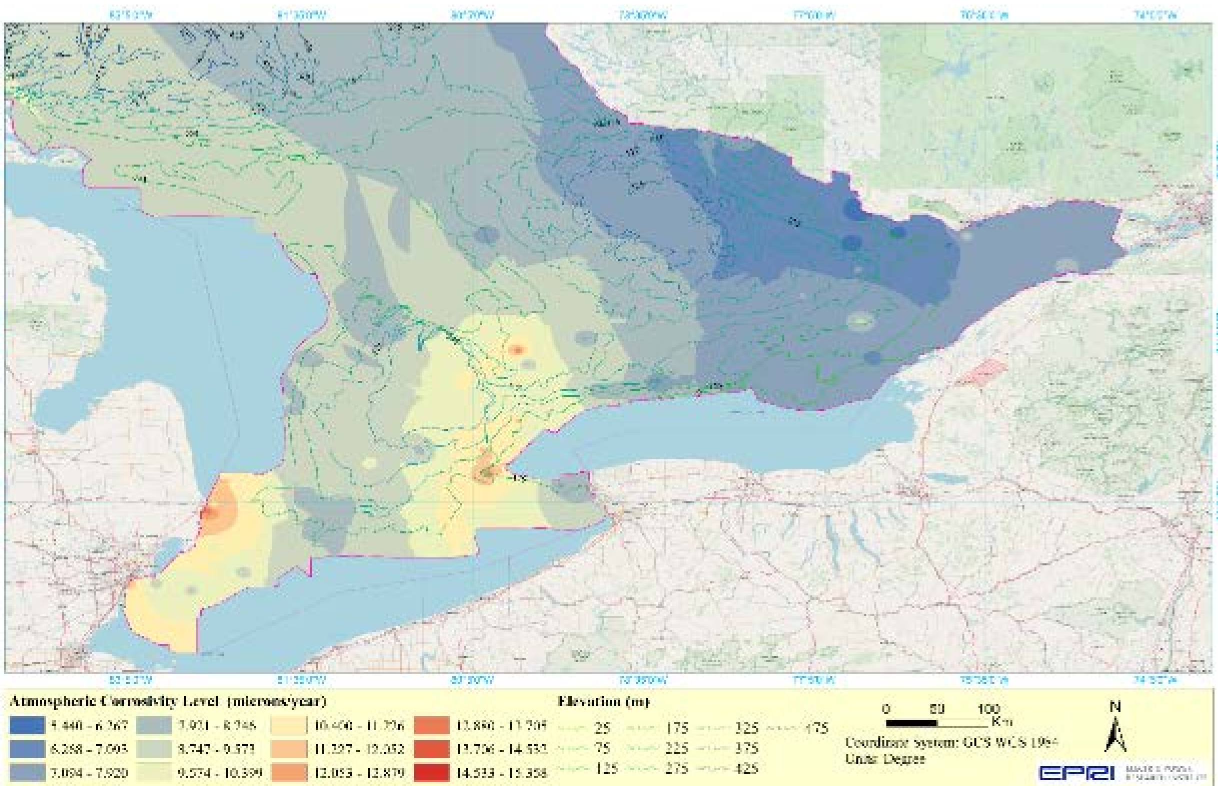

Figure 5-4 Atmospheric Corrosivity Map (μpy) for Steel Exposure

6 FUTURE RESEARCH

Additional field surveys and deployment of additional steel coupons will increase the resolution of the maps and reduce the margin of error in structure selection. A reduction in error of .8% provides a potential savings in structure selection of $560K. Areas where the resolution of the maps will benefit the most are near Sudbury and areas southeast of Sudbury.

7 CORROSION RATE DATA

Table 8 Steel Mass Loss Data (Aged Coupons)

Circuit #	Structure #	GPS coordinates		Steel Corrosion Rate (microns/year)
N6S	B3N_24	-82.4243783	42.9333167	17.9
X26S	33	-80.90581	46.5383117	17.9
X27A	57	-81.0044467	46.51589	17.2
X23N	82	-81.0645637	46.490061	16.5
N6S	B3N_19	-82.4243783	42.9333167	15.0
M27B/M28B	B12_92	-79.93267	43.2495495	14.5
V41N/L23N	V43N_7	-82.3927965	42.9115752	14.3
G13M3	253	-79.681821	44.324881	14.1
V41H/V42H	35	-79.67538	43.710357	13.7
Q23BM	15	-79.931114	43.241136	13.1
X504E	166	-80.5338683	46.1032733	12.8
L24L/L29C	10	-82.4400404	42.7963668	12.7
C21J	606	-83.0892561	42.2787516	12.7
B3 B4	111	-79.930583	43.1982755	12.3
J4E	35	-83.087391	42.278567	11.3
128	B560V	-79.7549564	43.6209228	11.1
B22D	32	-80.9989402	43.3441571	11.0
L26L/Idle 18	10	-82.4422117	42.7955267	10.9
N582L	253	-80.5979581	42.9197283	10.7
V71P	113	-79.429248	43.831328	10.7
B5G	21	-79.883481	43.341685	10.4
R19T/R17T	41	-79.655511	43.59263	10.3
N581M	48	-80.0795098	42.8874491	10.2
R19TH/R21TH	8	-79.588425	43.66288	10.2
N6S	10	-82.4189417	42.933205	10.0
W45LS	28	-81.2640619	42.8886053	9.9
N582L	49	-80.0810917	42.890136	9.9
R14T/R17T	9	-79.588016	43.662775	9.8
C4R	1040	-79.573545	43.68796	9.8
X1H	5	-76.670445	44.5822967	9.8
B22D	154	-81.3658082	43.5160125	9.7
M34H	122	-79.8423335	43.1846855	9.7
F11C	14	-80.4476387	43.4469723	9.6
C15L	40	-79.269404	43.744806	9.6
S2N	8	-81.6516625	42.9349144	9.5
L28C/L29C	120	-82.3585138	42.6112401	9.5
S7M	688	-75.7448634	45.3316013	9.5
Q23BM/Q24BM	238	-79.843362	43.184492	9.4
B562L/B563L	310	-81.6589292	43.734558	9.4
N21W	23	-82.359364	42.975707	9.3
R24C	50	-79.588746	43.663031	9.3
B28S	54	-81.43848	44.3939367	9.3

E27	197	-79.6904302	44.7688404	9.2
M33W	I-36	-80.8711648	43.0491422	9.1
L20H	15	-74.8684289	45.0609575	9.1
B22D	57	-81.0677298	43.3773984	9.0
V44	8	-79.6317818	43.7879859	8.9
B562L	389	-81.6342911	43.5422985	8.9
C23Z/C24Z	K2Z_525	-82.871797	42.282664	8.7
C4R	970	-79.417554	43.781654	8.6
W44LC/S47C	312	-82.093775	42.3880933	8.5
C24Z	35	-82.866071	42.279418	8.5
A24P	1B	-82.72435	46.2004417	8.5
B23D	41	-81.5018332	44.2827262	8.4
Q2AH	35	-79.14863	43.1200433	8.4
C21J/C23J	210	82.55202922	42.2235358	8.4
C28C	318	-77.1837117	44.80919	8.2
W37	19	-81.194572	42.973758	8.2
Q28A/Q29HM	Q23BM_41	-79.176575	43.1015383	8.1
C28C	868	-78.9480683	43.9456767	8.1
B562L	285	-81.6582156	43.7771737	8.0
G13M3	206	-79.6047597	44.2114362	7.9
D6V	367	-80.567805	43.469952	7.9
L1MB	20	-74.8692143	45.0498023	7.8
B562L	623	-81.5695609	42.9928781	7.6
D11K	10	-80.527207	43.436572	7.6
T9K	84	-81.4673395	42.7256119	7.5
W43L	460	-81.2649133	42.8884333	7.5
B28S	265	-80.909375	44.5591567	7.5
M81B	677	-79.0958467	44.43132	7.5
L2M	20	-74.868025	45.04724	7.5
X21	28	-76.9105633	44.19124	7.3
D5H	6	-77.71243	46.17582	7.3
B5QK	87	-76.696265	45.0482233	7.3
Q26M/Q25BM	33	-79.15095	43.11857	7.1
X503E	440	-79.9547366	45.3370654	7.0
B23C	771	-77.4760583	44.3356667	7.0
A4K	27	-75.631942	45.425755	6.8
Q3K	60	-76.5700968	44.2706849	6.7
Q5G/Q2AH	91	-79.3073142	43.1435422	6.7
X522A	449	-76.009315	44.848795	6.7
B23C	1000	-78.46076	44.0527083	6.6
X523A	627	-75.8989567	45.2575533	5.7
C27P	49	-76.3345317	45.360925	5.5
X1P	6	-76.6882917	45.5713683	5.4
W3B	89	-76.7523291	45.2536032	5.3
N93A	60	-91.5934233	48.7473533	3.7
P3B	60	-89.274818	48.441886	3.1
R1LB	58	-88.3581633	49.1572617	2.9
W21M	394	-86.291845	48.691615	2.9

M23L	351	-88.2621567	48.99292	2.6

Table 9 Galvanizing Loss Data (2017 Survey)

Circuit #	Structure #	GPS Coordinates	Zinc Corrosion Rate (microns per year)
B4V	2	43.91777833, -80.164725	2.3
B4V	31	43.96166833, -80.30547833	2.4
B4V	48	44.28785, -81.41209667	2.3
B4V	57	44.00206333, -80.43244167	2.3
B4V	90	44.05126833, -80.5915567	2.2
B4V	100	44.06609667, -80.64181	1.6
B4V	126	44.104105, -80.76744167	2.1
B4V	148	44.16912833, -81.03301168	1.2
B4V	154	44.149555, -80.89982667	2.0
B22D	7	44.31822382, -81.57406408	1.8
B22D	314	43.85892953, -81.20930545	1.2
B22D	469	43.5948093, -81.41901535	2.0
B31L	1A	45.23865333, -74.390035	0.9
B31L	66	45.14511833, -74.640965	1.7
B31L	96	45.11862333, -74.767335	1.5
B82V	823	44.132095, -79.48310833	1.3
B82V	882	43.98631162, -79.5823046	1.2
B82V	953	43.79333497, -79.61623106	1.0
D4W	55	43.35944667, -80.68756833	1.1
D4W	117	43.22540983, -80.84598873	1.8
D4W	181	43.08449608, -81.00949978	2.3
D5A	129	45.38768667, -74.89845	1.6
D5A	179	45.429045, -75.093475	1.5
D5A	220	45.46326333, -75.25530167	1.2
D5A	261	45.49724667, -75.41858167	1.3
D6V	180	43.91231833, -80.16111167	1.3
D6V	242	43.76820833, -80.284115	0.3
D6V	303	43.61584667, -80.41121833	0.7
E8V	7	44.34401667, -79.82028999	1.0
E8V	64	44.19593833, -79.90772166	0.4
E8V	124	44.05092333, -80.04525167	1.5
H23S	204	46.41046667, -79.46579333	1.0
H23S	232	46.40753833, -79.57415	1.0
L2M	B141	44.84665663, -75.39857445	1.7
L2M	B191	44.74051252, -75.53802663	1.8
L2M	B22	45.02794437, -75.00249342	1.4
L2M	B248	44.62813412, -75.68845635	1.4

L2M	B84	44.92952793, -75.20818575	1.4
L24A	44	45.17200282, -75.05447524	1.4
L24A	106	45.26867857, -75.34714343	1.3
L24L	71	42.81423303, -82.30503797	1.7
L24L	119	42.81549417, -82.17136277	1.8
L24L	168	42.8166433, -82.03644983	2.2
L24L	220	42.81771148, -81.89367945	2.0
L24L	268	42.81859257, -81.76143865	2.0
L28C	72	42.68019417, -82.43679505	0.8
L28C	168	42.53498272, -82.27463147	1.7
L28C	218	42.4600717, -82.18263083	1.7
M32W	5	43.13102167,-80.03972833	1.8
M32W	25	43.11979667, -80.12848333	1.2
M32W	53	43.08135167, -80.25982167	1.8
M32W	83	43.049545, -80.40593333	1.4
M32W	103	43.031875, -80.51572667	1.4
M32W	137	43.00729333, -80.69688167	0.9
M32W	170	42.98965333, -80.82781833	2.1
M32W	204	42.96509833, -80.98564167	1.0
M32W	234	42.94575333, -81.12979833	1.7
M80B	673	44.44626833, -79.0845	1.6
M80B	720	44.335935, -79.18880499	1.2
M80B	769	44.24475167, -79.3368	1.7
P15C	8	44.29445167, -78.40810333	0.9
P15C	66	44.17804, -78.59022667	0.4
P15C	142	44.034405, -78.84113833	2.3
P15C	236	43.86316667, -79.095825	1.8
P502X	617	47.51847333, -81.04196167	1.1
P502X	685	47.25602667, -80.99864166	1.3
P502X	854	46.63618, -80.91659167	2.3
Q6S	60	44.27962, -76.71424	1.7
Q6S	106	44.271245, -76.88209333	1.6
Q6S	157	44.25035833, -77.06615333	1.2
Q6S	207	44.22164667, -77.24486667	1.5
Q6S	250	44.18713, -77.39307	0.7
R14T	69	43.549379, -79.704161	0.7
W42L	319	42.81937452, -81.61982848	1.3
W42L	373	42.81999373, -81.47343238	2.0
W42L	422	42.8499448, -81.34787088	1.5
W43L	498	42.93709263, -81.19117903	2.2
W44LC	2	42.93686748, -81.19098887	0.9
W44LC	58	42.82660343, -81.33707737	1.5
W44LC	100	42.742375, -81.45271267	1.5

W44LC	155	42.64775667, -81.61736667	0.3
W44LC	199	42.57313167, -81.749875	2.0
W44LC	242	42.50250167, -81.877955	0.0
W44LC	278	42.44695833, -81.988395	1.3
X1H	64	44.36524833, -76.62525168	1.3
X2H	43	44.44158167, -76.66189834	1.7
X503E	78	46.3934208, -80.7877657	0.6
X503E	178	46.10503373, -80.53400523	0.9
X503E	402	45.4469585, -80.0204095	1.3
X503E	522	45.08143447, -79.79973222	0.8
X503E	622	44.76922328, -79.68968995	1.1
X503E	727	44.44187565, -79.79334528	0.8
X504E	232	45.90190333, -80.33905	1.2

Table 10 Galvanizing Loss Data (2013 Survey)

Structure #	Circuit #	Latitude	Longitude	Zinc Corrosion Rate (microns per year)
771	B23C	-77.47605834	44.33566667	2.3
1000	B23C	-78.46076	44.05270833	2.3
82	B3B4			1.6
83	B3B4	-79.93181	43.249766	3.2
86	B3B4	-79.930689	43.2413615	2.0
110	B3B4	-79.93246	43.198743	2.0
19	B3N	-82.43402477	42.92641982	3.2
100	B541C	-78.90503713	43.9667496	5.9
100	B542C	-78.90513167	43.96716667	8.0
21	B5GB6G	-80.28059978	43.53827932	3.1
87	B5Q5	-76.696265	45.04822333	0.9
4	C14L	-79.268496	43.744363	3.3
40	C15L	-79.269404	43.744806	2.0
210	C18R	-79.577485	43.686134	2.0
121	C20R	-79.417182	43.782345	1.7
220	C23Z			4.5
35	C23Z C24Z	-82.866071	42.279418	3.2
456	C24Z	-82.57244898	42.21704388	2.3
651	C28C	-78.31248	44.23804167	2.4
855	C28C	-78.90537	43.96765167	2.3
970	C4R	-79.417554	43.781654	2.7
1040	C4R	-79.573545	43.68796	2.7
113	C551V	-79.429794	43.831726	1.0
117	C552V	-79.430428	43.831991	8.8
10	D11K	-80.527207	43.436572	2.0

367	D6V	-80.56780499	43.469952	1.3
14	F11C	-80.44763869	43.4469723	2.1
97	H24C	-78.90500333	43.96629	1.9
682	H24C	-78.31124	44.23943833	2.3
643	H26C	-78.311595	44.23888667	2.3
35	J4E	-83.087391	42.278567	3.1
525	K2Z	-82.872983	42.282473	1.6
15	L20H	-74.86842893	45.06095745	1.5
15	L21H			3.1
138	L24A	-75.48101597	45.34033133	3.4
10	L24L	-82.44282383	42.79640773	4.5
10	L26L	-82.44221167	42.79552667	4.3
11	L26L Idle			2.6
120	L28C	-82.35496287	42.60864572	4.3
33	L5S	-79.271408	43.744935	1.8
189	M20D	-80.5453799	43.41729495	3.1
86	M27B	-79.9316765	43.242721	1.3
88	M27B	-79.93267	43.2495495	3.1
392	M29C	-76.69642167	45.04831333	0.9
857	M29C	-78.312055	44.23773	2.4
49	N1M	-80.07858333	42.88886833	1.0
10	N4S	-82.42064	42.93347	3.0
48	N580M	-80.08011113	42.89031527	0.9
47	N581M	-80.07950978	42.88744908	3.2
49	N582M	-80.08109165	42.89013602	4.6
49	N5M	-80.07906167	42.88879167	2.6
10	N6S	-82.41894167	42.933205	3.2
1074	P21R	-79.57494	43.686624	3.0
1006	P22R	-79.41747834	43.78200333	0.8
15	Q23BM	-79.931114	43.241136	1.6
18	Q23BM	-79.105679	43.135234	3.2
33	Q23BM	-79.96158137	43.1432082	2.6
41	Q23BM	-79.99260328	43.14059153	3.3
233	Q23BM	-79.85936518	43.1877772	2.1
41	Q25BM	-79.89116101	43.29908	0.8
228	Q25BM	-79.84541333	43.18434333	1.7
33	Q26M	-79.28520667	43.07112887	3.3
39	Q28A Q29HM	-79.17209492	43.10459468	3.3
238	Q29HM			2.3
35	Q2AH	-79.14863	43.12004333	1.8
35	Q30M			4.5
41	Q30M	-79.17226348	43.1049111	2.1
91	Q5G	-79.30731417	43.14354222	1.2

9	R14T	-79.588425	43.66288	1.6
8	R19TH	-79.585236	43.667111	1.8
2	R1K	-79.57678032	43.68118775	3.0
50	R24C	-79.586133	43.667109	1.6
58	r24c	-79.579122	43.681996	1.0
40	S2B	-81.05904732	46.4951514	1.2
7	V43N	-82.39267058	42.91807463	4.1
113	V71P	-79.429248	43.831328	1.7
84	V74R	-79.5783	43.6864	
460	W42L W43L	-81.26491333	42.88843333	4.5
4	W44LC			3.2
28	W45LS	-81.26406193	42.88860525	3.2
57	X27A	-81.00444667	46.51589	2.2
G26	X4H	-76.56923303	44.27027062	5.2
111	X74P	-81.33095833	46.44775	1.7

Table 11 Galvanizing Loss Data (2001 Survey)

Latitude	Longitude	Zinc Corrosion Rate (microns per year)
42.9908333	-81.1436111	0.062
42.9258333	-81.1891667	0.084
43.1502778	-79.3122222	0.013
43.1688889	-79.2758333	0.033
48.4216667	-89.2802778	0.075
43.9508333	-78.9422222	0.028
44.3366667	-78.3580556	0.039
43.6525000	-79.3561111	0.038
43.6750000	-79.5886111	0.080
43.7836111	-79.4513889	0.083
45.0966667	-74.9030556	0.056
42.9388889	-82.4097222	0.092
45.4319444	-75.6422222	0.038
46.5141667	-81.0241667	0.146
46.5030556	-81.0650000	0.146
43.2438889	-79.9411111	0.040
43.6752778	-79.5894444	0.104
43.7841667	-79.4516667	0.052
43.4722222	-80.5686111	0.044
42.9638889	-81.2244444	0.075
43.3472222	-79.8836111	-0.013
44.3050000	-78.4100000	0.039
42.3019444	-83.0383333	0.013

42.3002778	-83.0369444	0.013
42.2980556	-83.0358333	-0.015
42.2858333	-83.0891667	0.056
43.1080556	-79.1761111	0.025
42.9272222	-82.4530556	0.158
42.9263889	-82.4569444	0.053
43.1344444	-79.1305556	0.065
43.1080556	-79.1766667	0.071
43.4116667	-80.5394444	0.053
45.0566667	-74.8688889	0.084
48.4216667	-89.2838889	0.080
45.0955556	-74.8408333	0.040
48.6861111	-93.2586111	0.058
43.5808333	-79.5563889	0.101
43.5811111	-79.5569444	0.030
46.4919444	-80.8741667	0.101
43.9380556	-78.8575000	0.102
46.5266667	-81.0075000	0.101
46.5080556	-81.0588889	0.068
43.1558333	-79.1600000	0.118
43.2916667	-79.7844444	0.097
43.4177778	-80.6702778	0.081
42.8544444	-80.0747222	0.098
42.8547222	-80.0741667	0.108
48.6527778	-90.4738889	0.075
48.6211111	-93.4036111	0.108
42.8922222	-80.0888889	0.102
42.8336111	-80.0666667	0.061
42.9677778	-82.3697222	0.193
48.4013889	-89.2283333	0.256
43.2641667	-78.2758333	0.175
45.8838889	-78.8847222	0.163
43.7205556	-79.2861111	0.323
46.5325000	-81.0711111	0.015
46.4869444	-81.2152778	0.255
46.4572222	-81.3405556	0.173
43.7252778	-79.5950000	0.243
45.3672222	-75.6616667	0.149

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800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

Polymer Insulator Population Assessment

Final Report, February 2018

EPRI Project Manager and staff
J. Kuffel
A. Phillips
F. Bologna
T. Shaw

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

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ABSTRACT

Hydro One is concerned with the condition of their polymer transmission line insulators. At their request, EPRI performed a condition assessment of 87 polymer insulators which were removed from service for the study. The condition of the insulators was evaluated through a series of tests. Findings were made based upon the test results. Those findings were used to formulate recommendations on how Hydro One can minimize reliability and safety risks and costs associated with their transmission line polymer insulator population.

Keywords

Polymer insulator, NCI, Condition assessment

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1
INTRODUCTION

Hydro One has a sizeable population of 230 and 115 kV polymer insulators. A significant portion of the 230 kV installed base is showing signs of deterioration. The deterioration appears due to corona activity on the insulator housing as a result of inadequately controlled electric fields. There have been several failures in the past two years. Two of these failures resulted in line drops.

Hydro One requested EPRI to perform a condition assessment of part of their polymer insulator population to in order to provide Hydro One technical data required to determine if a replacement program is warranted. The study focused on three particular insulator configurations:

- 230 kV suspension with large corona rings
- 230 kV suspension with either small (often referred to as a 'donut') or no corona rings
- 115 kV dead end.

Hydro One removed a total of 87 polymer insulators for analysis. The samples were removed from lattice and from wood pole structures.

It was recognized that locations with significant wetting or contamination would be the optimum environment from which the insulators should be removed. Based upon that, most of the insulators were removed from circuits in Southern Ontario.

2
INSULATOR SAMPLE

A total of 87 polymer insulators were removed from service and provided to EPRI for assessment. Figure 2-1 and Figure 2-2 give a breakdown of the insulators with respect to system voltage and manufacturer.

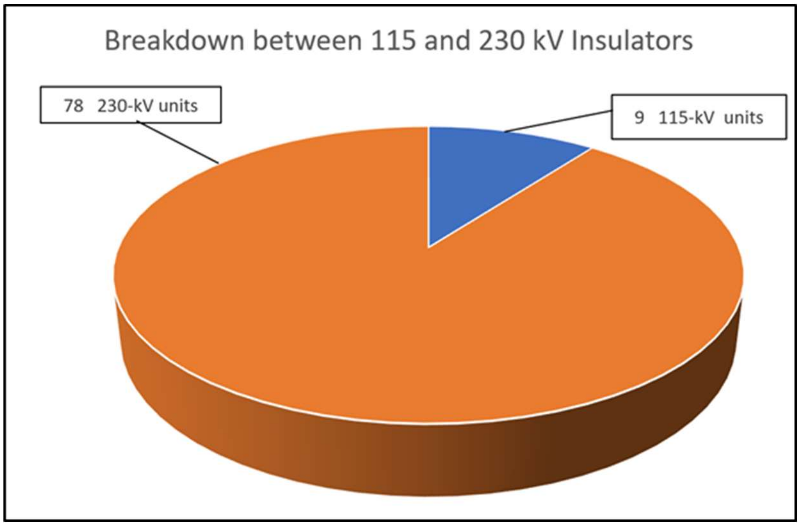


Figure 2-1
Breakdown of the insulator sample according to system voltage

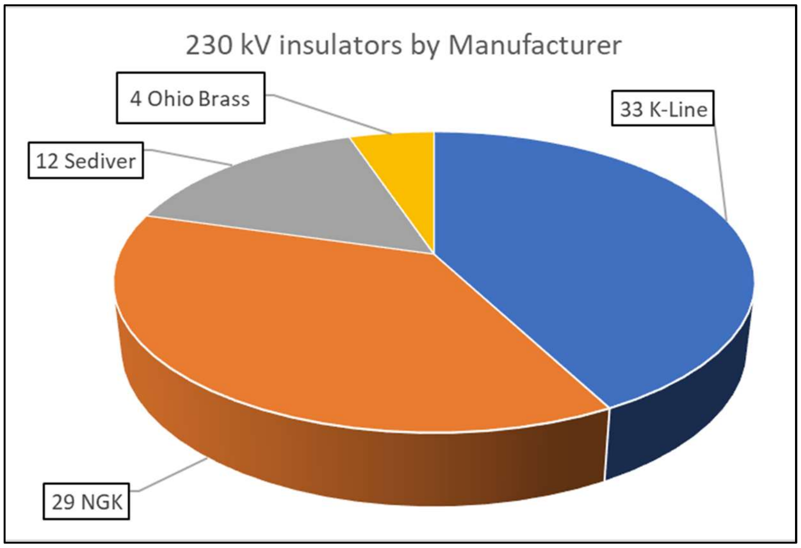


Figure 2-2
Breakdown of 230 kV insulator sample according to manufacturer

Figure 2-3 through Figure 2-5 show the mix of age included in the insulator sample. The K-Line and NGK insulators were stamped with manufacturing date information. The Sediver and OB insulators had no markings and therefore it was not possible to ascertain their age.

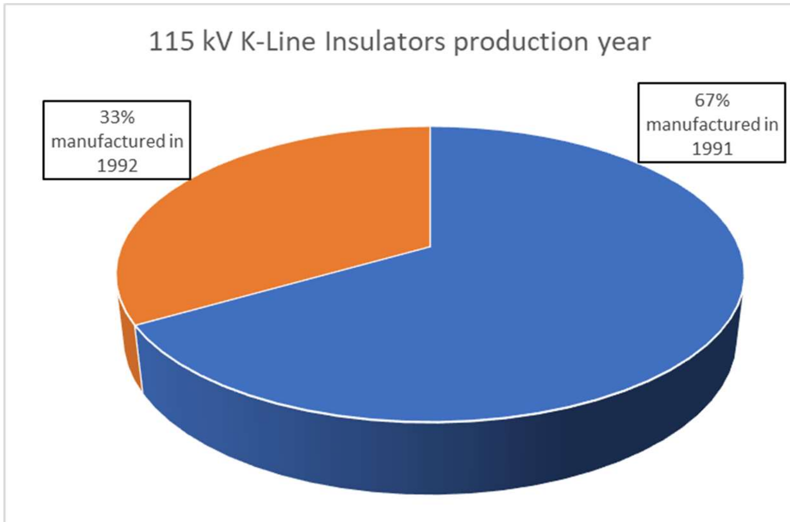


Figure 2-3
Age distribution of the 115 kV K-Line sample insulators (9 units in total)

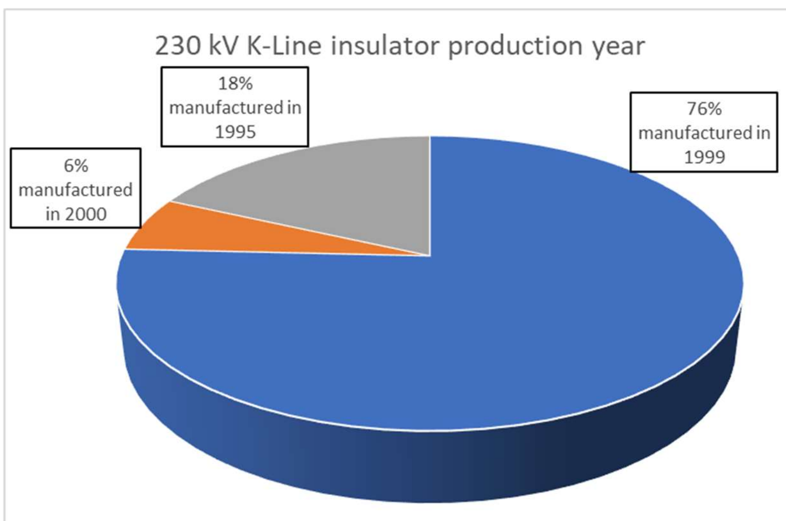


Figure 2-4
Age distribution of the 230 kV K-Line sample insulators (33 units in total)

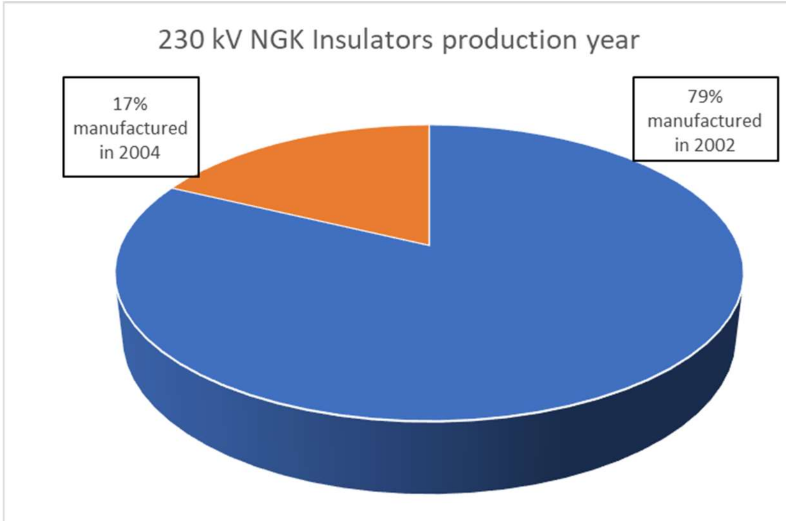


Figure 2-5
Age distribution of the 230 kV NGK sample insulators (29 units in total)

As the above figures show, the 115 kV K-Line insulators had been in service for 25 to 26 years. Eighty-two percent of the 230 kV K-Line insulators had been in service for between 17 and 18 years, while eighteen percent had been in operation for 22 years. The NGK insulators had been installed on the system for between 13 and 15 years.

Some of the removed insulators were fitted with corona rings and others were not. Figure 2-6 shows photographs of the various types of corona rings found on the sample insulators.

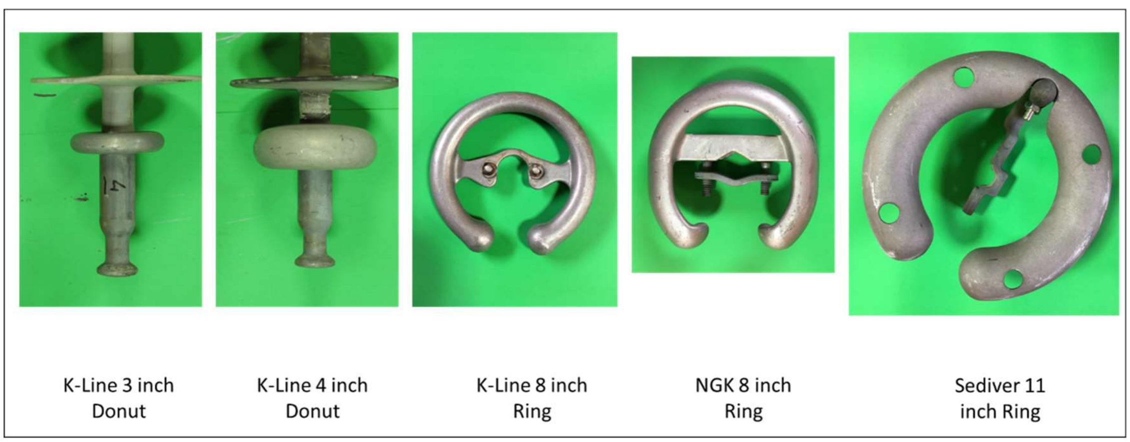


Figure 2-6
Various corona rings present on sample insulators

Details of which insulators were fitted with corona rings and the size of the ring when present are given in Table 2-1.

Table 2-1
Number of Insulators with and without corona rings

Manufacturer	Voltage rating	Total # of units	# of units without corona rings	# of units with corona rings	# of units with				
					K-Line 3 inch donut	K-Line 4 inch donut	K-Line 8 inch ring	NGK 8 inch ring	Sediver 11 inch ring
K-Line	115 kV	9	0	9	9	-	-	-	-
K-Line	230 kV	33	0	33	-	6	27	-	-
NGK	230 kV	29	6	23	-	-	-	23	-
Sediver	230 kV	12	0	12	-	-	-	-	12
Ohio Brass	230 kV	4	4	0	-	-	-	-	-

3
TEST PROGRAM

The insulator assessment included the following tasks:

Visual Inspection

- Each of the insulators was visually inspected and photographed. Any visually evident damage was noted.

Hydrophobicity Assessment

- The hydrophobicity of the polymer material making up the insulator housing was assessed for each insulator using method 3 recommended in IEC 62073, “Guidance on the measurement of wettability of insulator surfaces” [1]. The assessment was done on the shank portions of the insulator housing.

Dye Penetration Testing

- Dye penetration tests were performed on one half of the insulators. The tests were performed in accordance with clause 5.2.2 of CSA 411.4-2010.

Water Vapor Ingress Testing

- Water vapor ingress tests were performed on one half of the insulators.

Moisture Penetration Test of the End-fittings

- The integrity of the end fitting seals was checked for both end-fittings on each insulator. The tests were performed in accordance with clause 5.7.3.2 of CSA 411.4-2010.

4
TEST RESULTS

4.1 Visual Inspection

A visual inspection was performed on each of the insulators. The inspection revealed issues of concern with a number of the units. Several forms of degradation were observed. These included damage associated with flashover and the ensuing power follow current, mechanical damage to sheds such as tearing and breakage, damage to the rubber housing due to excessively high electric fields at the rubber surface, and reduction of hydrophobicity due to electrical discharges on the rubber surface. Each of these issues are addressed in the following sub-sections. Detailed explanations of the significance of each of these visually identifiable issues are provided in EPRI's Field Guide for Visual Inspection of Polymer Insulators [2].

4.1.1 Damage due to Flashover and Power Follow-On Current

Several insulators showed varying degrees of damage due to flashover and the ensuing power arcs. This type of damage is relatively independent of the insulator design and manufacturer since power arc tests are included in the relevant CSA standards to which manufacturers must qualify their products. As such, all of the insulators that had been exposed to power arcs were grouped together. Other issues such as ageing and deterioration of the rubber housings, deterioration of the seals at the triple junction between end-fittings, the fibreglass rod, and the rubber housing, and deterioration of the fibreglass rod are highly dependent upon the manufacturer. For this reason, insulators showing the latter form of deterioration are grouped according to system voltage and manufacturer.

Five of the inspected insulators showed flash marks on the corona rings and/or end fittings due to flashover and power follow current. Two of these were 115 kV units and three were 230 kV. Photographs showing the damage are given in Figure 4-1.

Figure 4-1
Localized damage due to flashover and power arc current

4.1.2 Physical Shed Damage

Eight of the 230 kV K-Line insulators were found to have damaged sheds. The damage took the form of portions of shed being missing, but the damage was limited to the sheds alone. Figure 4-2 shows examples of the observed damage. It is not clear whether this damage was sustained while the insulators were in service or whether they were damaged post removal.

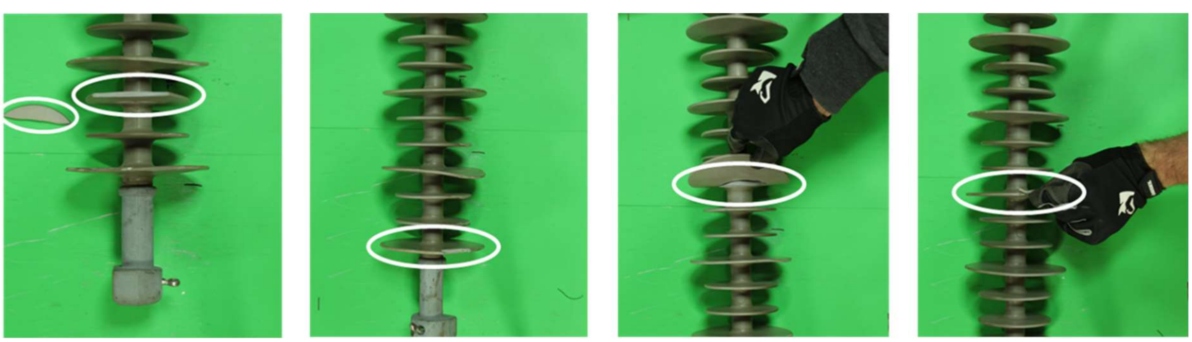


Figure 4-2
Examples of shed damage observed on 230 kV K-Line insulators

There were no instances of damage to more than one shed on any one insulator. Furthermore, there was no evidence of damage to the rubber housing on the shank of those insulators. Based upon this, the shed damage is not considered critical to the insulators' service performance or longevity. The nature of the damage suggests that, at least in some cases, the rubber may be becoming somewhat brittle. The chemical formulation of the rubber housing is proprietary to the manufacturers and as such K-Line should be contacted and asked for their input.

4.1.3 Corona Discharge Induced Damage

The most significant visual observations comprised deterioration of the rubber housing on the insulator shank near the line end, and deterioration of the end fitting seals at the triple junction. This type of damage is known to be manifested due to the presence of unacceptably high electric fields on the surface of the rubber housing at the insulator line end [3].

Extensive visible deterioration of the rubber (to varying degrees) attributable to excessive electric fields was present on all K-Line 230 kV insulators with 4-inch donut corona rings and all 230 kV NGK insulators installed without corona rings. In addition to this, a number of NGK insulators fitted with 8-inch corona rings showed visually observable rubber deterioration in the line-end areas of the housing and the triple junction seals. The 230 kV Ohio Brass insulators, all of which were installed with no corona rings also showed significant rubber and end-fitting seal damage due to excessively high electric fields on the rubber surface at the line end of the insulators. There was little evidence of damage or deterioration on any of the 230 kV Sediver insulators which were all installed with 11-inch corona rings. Inspection of the 230 kV K-Line insulators fitted with 8-inch corona rings showed no visual damage. The nine 115 kV K-Line dead-end insulators installed with 3-inch donut corona rings showed no significant visually observable deterioration of the rubber housing and seal areas other than unit 85 which had been exposed to a flashover and power follow current.

4.1.3.1 230 kV K-Line insulators with 4-inch donut corona rings

Figure 4-3 through Figure 4-5 show sample photographs of damage to the line-end rubber housing and the line-end fitting seals on the 230 kV K-Line insulators installed with the 4-inch donut corona ring, the 230 kV NGK insulators installed with no corona rings, and the 230 kV Ohio Brass insulators installed with no corona rings.

Figure 4-3 shows the spectrum of damage to the line end of 230 kV K-Line insulators installed with the 4-inch donut corona rings (Units 79 to 84).

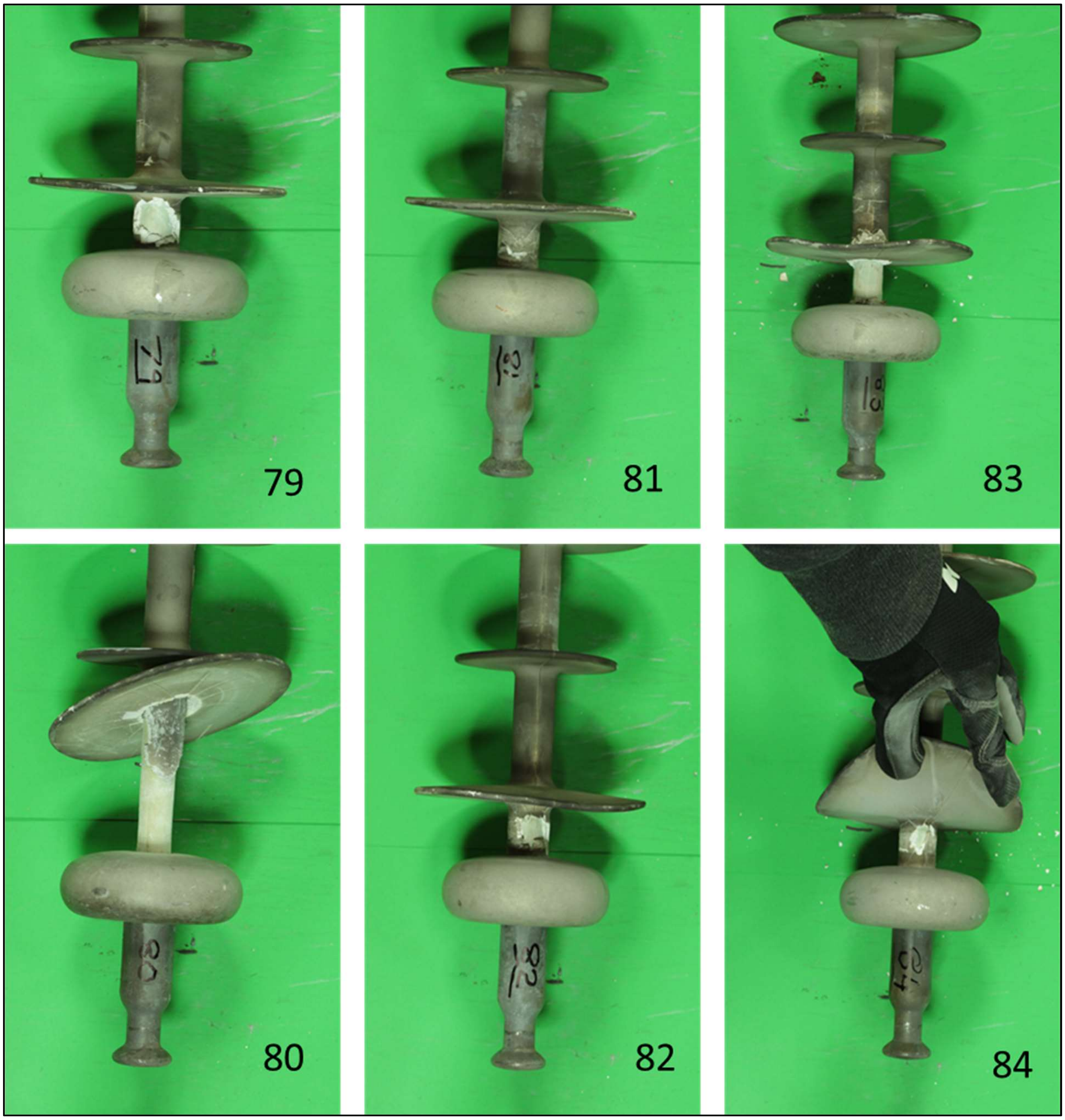


Figure 4-3
Corona damage observed on all six of the removed 230 K-Line Insulators fitted with small donut corona rings

The damage shown in Figure 4-3 spans from very serious rubber damage leading to the beginnings of rod exposure on insulator 81 to catastrophic rubber erosion, line-end shed cracking, line-end shed separation, and full rod exposure on insulator 80. Damage such as this has been undisputedly shown to result from inadequate grading of the electric field at the insulator line end. Simply put, the donut corona ring utilized on these 22-year-old insulators is too small to provide adequate electric field grading at the insulators' line end. The insulators shown in Figure 4-3 are of a design that was discontinued in the 1990s. All six of these early design insulators included in the sample showed damage sufficient to recommend their immediate removal from service. In fact, Hydro One experienced a line drop in 2016 due to the failure of this type of insulator. The details of the investigation are provided in Appendix A. The newer K-Line designs incorporate 8-inch diameter corona rings which provide far improved electric field grading.

4.1.3.2 230 kV NGK insulators with no corona rings

Figure 4-4 illustrates the varying degrees of damage to the line-end rubber housing and the secondary seal on 230 kV NGK insulators installed without any corona rings.

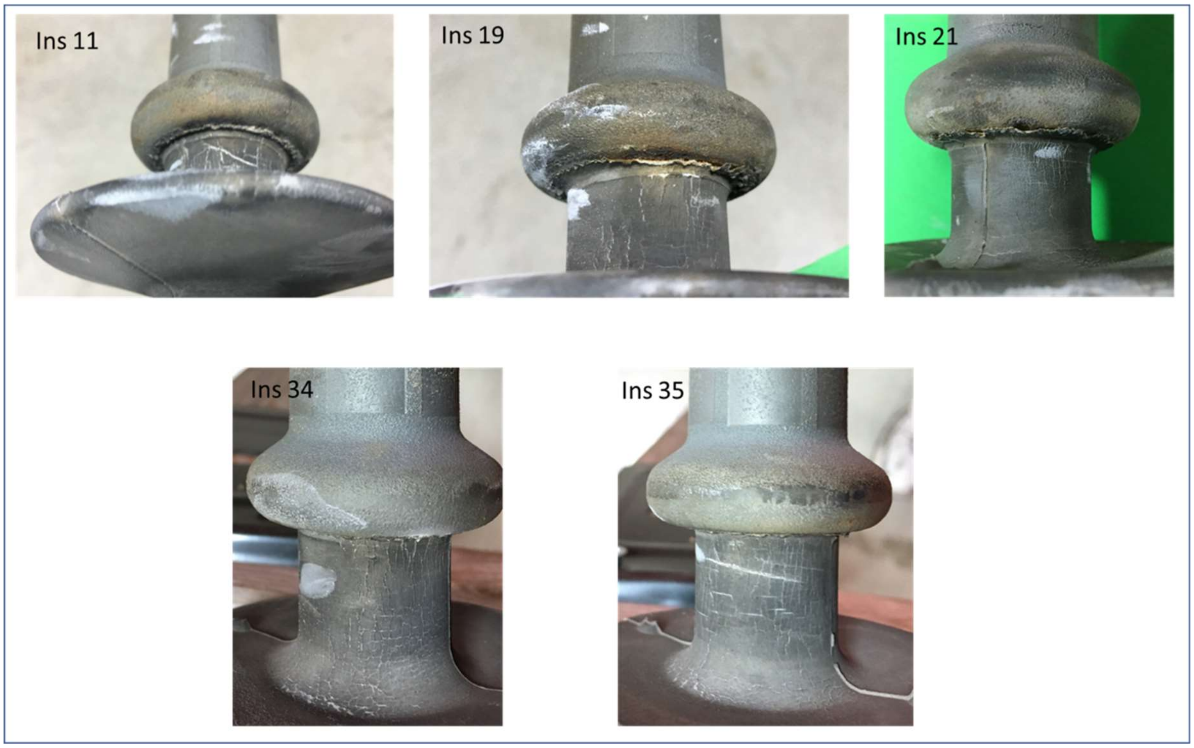


Figure 4-4
Corona damage observed on 230 NGK Insulators installed without corona rings

The cracking, erosion, and degradation of the rubber housing at the insulators' line end and the deterioration of the seal at the insulators' triple junction shown in Figure 4-4 are a direct result of the lack of adequate electric field grading. As is now commonly understood, polymer insulators installed at 230 kV voltage levels require corona rings which are designed so as to maintain an acceptably low electric field on the surface of the insulator rubber housing. The cracking observed on these units is similar to that observed on failed units analysed by EPRI from other utilities as well as a unit that failed in EPRI's 230kV accelerated aging test [4].

4.1.3.3 230 kV Ohio Brass insulators installed with no corona rings

The four Ohio Brass Hi-Lite insulators included in the sample were older units constructed using single sheds/shank units slid on to a fiberglass rod together with a silicone grease. The seals between the sheds are maintained by compression. This is often called the "top hat design" and these insulators are known to suffer from splitting of the shank as they age [2]. All four were installed without corona rings. They suffered deterioration of the rubber at the line end of the insulators and damage to the line-end fitting triple junction seal. Figure 4-5 shows the degree of damage. Note the small areas of corrosion on the end fitting. These are often the location of prolonged corona activity.

Figure 4-5
Damage to OB insulator line-end rubber and seal observed with no corona rings

The understanding of the importance of electric field grading when utilizing polymer insulators on transmission systems has become well recognized over the past 20 years and corona ring application guidelines have been provided by EPRI as well as by most of the major polymer insulator manufacturers supplying the North American market. These guidelines are summarized in an EPRI publication which provides explanations and guidance on the need for and on the design requirements of corona rings for transmission class polymer insulators [3].

4.1.3.4 230 kV NGK insulators with 8-inch corona rings

The design of the 8-inch corona ring fitted on the 230 kV NGK insulators has been shown inadequate both in the EPRI ageing chamber tests [4] and EPRI investigations into in-service failures [see Appendix B]. While the ring itself performs well, the shape of the ring's mounting bracket results in an excessively high electric field on the insulator rubber housing just above the line-end fitting. Figure 4-6 illustrates the issue.

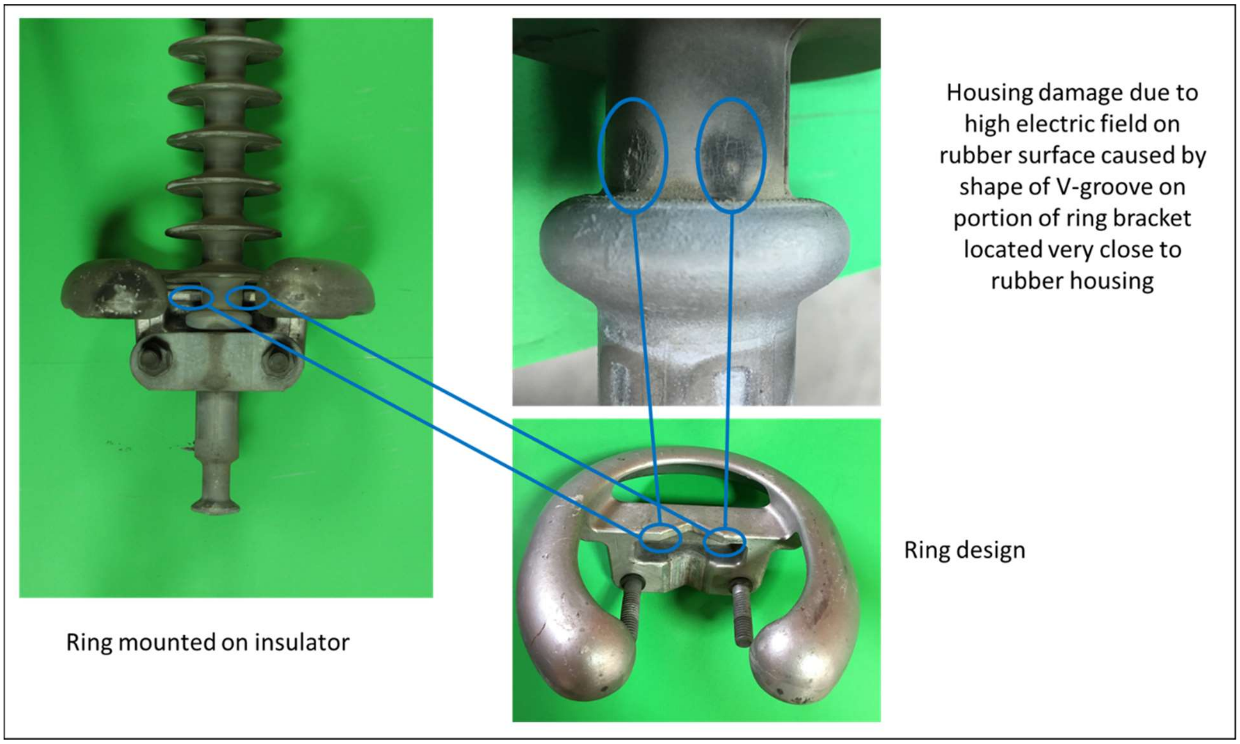


Figure 4-6
Damage to 230 kV NGK insulator due to corona ring mounting bracket

The detailed mechanism of the rubber damage due to the ring design is explained in the EPRI document given as Appendix B.

Visual inspection of the line-end housing on the 230 kV NGK insulators with the 8-inch corona rings removed from service shows a rather wide range of damage. Some insulators showed virtually no damage at all, while others showed significant rubber erosion. This same effect has been observed by EPRI on insulators removed from the field and in the EPRI aging chamber. It has been attributed to small differences in the rubber consistency and moulding process between different insulators. The range of damage observed is shown in Figure 4-7.

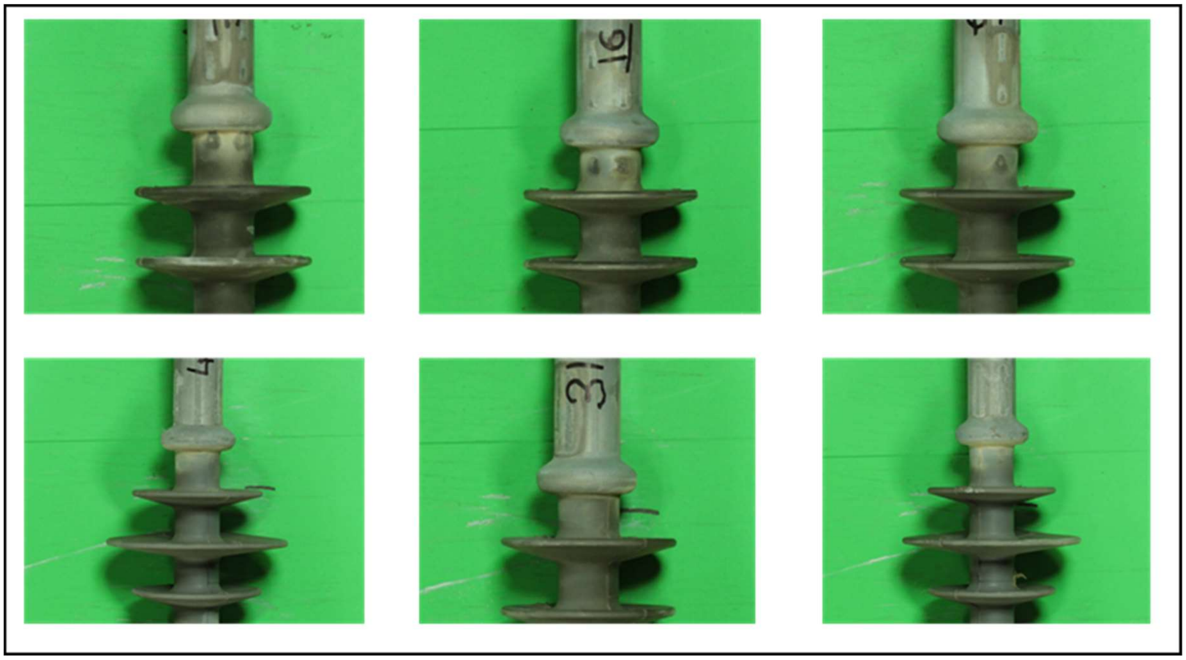


Figure 4-7
Range of damage observed on NGK insulators due to 8-inch corona ring design

As can be seen from Figure 4-7, the deterioration due to the use of the poorly designed corona ring varied across the insulator sample.

4.2 Hydrophobicity Tests

Hydrophobicity testing was performed in accordance with Method C of IEC TS62073, Guidance on the Measurement of Wettability of Insulator Surfaces [1]. The hydrophobicity of the shank on each of the sample insulators was measured in three locations: at the line end, in the middle of the insulator, and at the ground end. The hydrophobicity was quantified using the wettability classifications given in IEC TS62073. The wettability classifications for the various insulators are given in Figure 4-8 through Figure 4-12, where 1 indicates a high level of Hydrophobicity and 7 a low level.

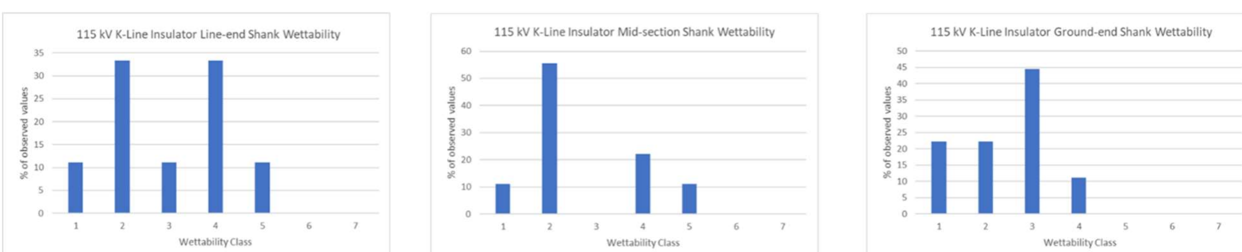


Figure 4-8
Hydrophobicity of 115 kV K-Line insulators

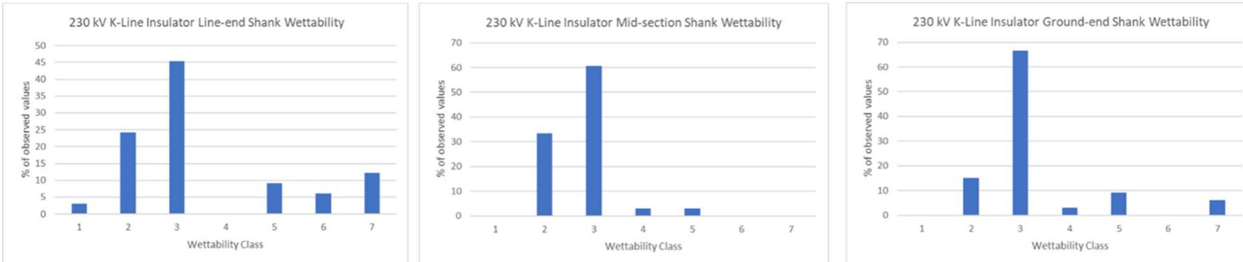


Figure 4-9
Hydrophobicity of 230 kV K-Line insulators

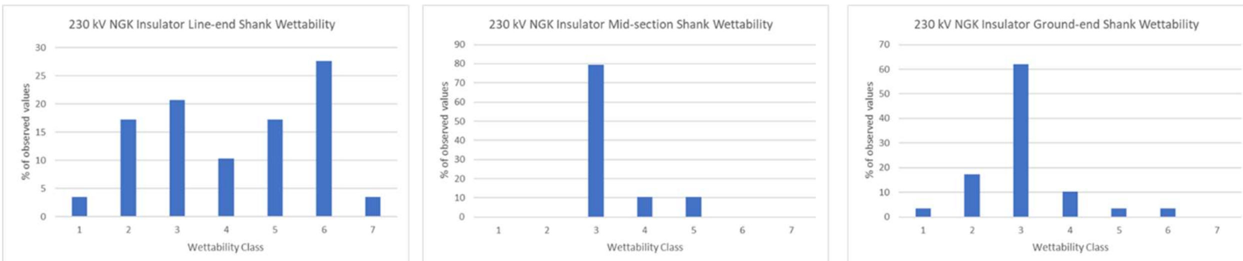


Figure 4-10
Hydrophobicity of 230 kV NGK insulators

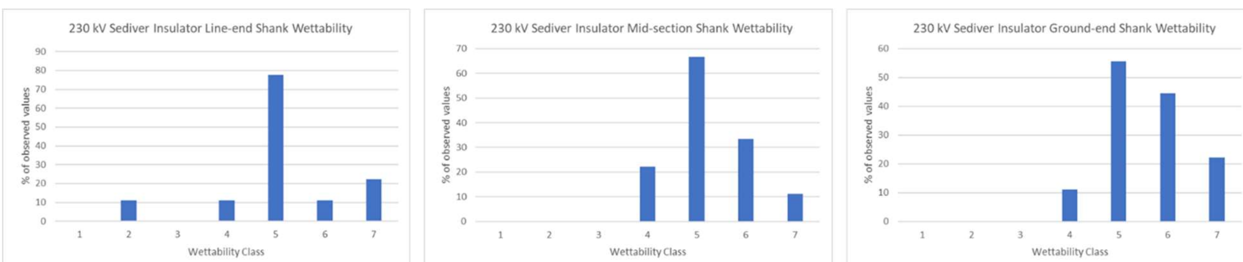


Figure 4-11
Hydrophobicity of 230 kV Sediver insulators

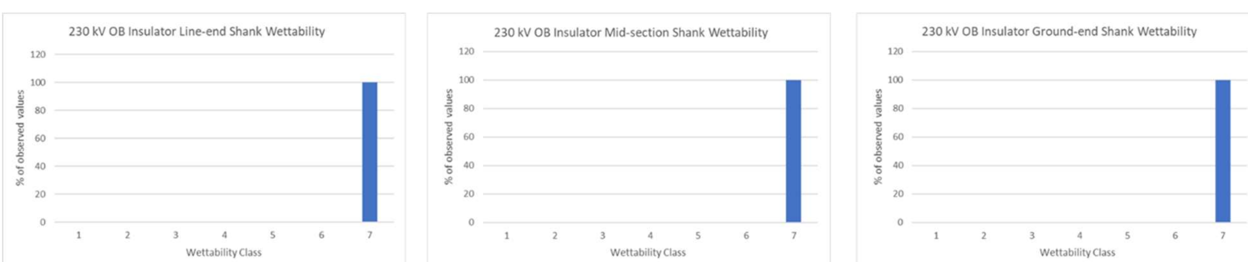


Figure 4-12
Hydrophobicity of 230 kV Ohio Brass insulators

Given their age, the silicone insulators (115 kV K-Line, 230 kV K-Line, and 230 kV NGK) have reasonable good hydrophobicity (Figure 4-8. Figure 4-9, and Figure 4-10) given their time in service. Insulators which had deteriorated rubber housings gave higher wettability readings. As expected, the non-silicone insulators showed higher levels of wettability (Figure 4-11 and Figure 4-12). The Sediver units were somewhat hydrophobic while the Ohio Brass insulators were completely hydrophilic.

4.3 Dye Penetration Test

Dye penetration testing is normally performed as a part of insulator qualification under CSA, ANSI, and IEC standards. It is intended to ensure that moisture is not able to wick vertically through the fiberglass rod or between the rubber housing and the fiberglass rod. In essence, the test checks the integrity of the fiberglass rod and the bond between the outer surface of the rod and the rubber housing. Forty-one of the sample insulators were subjected to dye penetration testing.

The dye penetration tests were performed in accordance with clause 5.4.1.2 of CSA 411.4-2010. Ten samples were cut from each tested insulator. The cuts were made at 90° to the axis of the core with a diamond-coated circular saw blade under running water. The cut surfaces were then smoothed by fine abrasive cloth and cleaned. The lengths of the samples were within the range of 10 mm ± 0.5 mm. The housing material was not removed from the samples.

The specimens were placed (fibres vertical) on a layer of steel balls of uniform diameter (1 to 2 mm) in a tray. A 1% methyl or ethyl alcohol solution of fuchsine dye was poured into the vessel, until the level of the dye was 2 to 3 mm above the balls. The specimens remained in place for a period of 15 mins. The pass requirement for the test is that there is no evidence of dye on the upper surface of the specimens after they have been in place for a period of 15 mins.

Four insulators failed to pass the test requirements. The details of the failures are given in Table 4-1.

Table 4-1
Insulators failing the dye penetration test

Insulator #	Voltage	Manufacturer	Manufacture Date	Comment
21	230 kV	NGK	2020	Samples 6 & 7 showed dye coming up through rod after 4 mins
24	230 kV	Sediver	Unknown	4 of 10 samples showed dye coming up through interface immediately
43	230 kV	K-Line	1999	1 of 10 samples showed dye coming up through the center of the rod
87	115 kV	K-Line	1992	3 of 10 samples showed dye coming up through a crack in the rod

4.4 Water Vapor Ingress Testing

Forty-four insulators were subjected to water vapor ingress testing. The test is intended to check the bonding between the fiberglass rod and the rubber housing. It is recognized that water vapor can penetrate through the silicone rubber housing of an insulator. In order to ensure that any such water vapor does not condense between the housing and the fiberglass rod, the housing is bonded to the rod. If the bond is poor or defective in some other fashion, moisture will settle at the housing-rod interface.

The test comprised conditioning the insulators for a 7-day period in a chamber with relative humidity above 90% and a temperature of 20 ºC. Following the seven-day conditioning period, the insulators were removed from the chamber and subjected to a 60 Hz withstand test. The test voltage applied across the insulators was 100 kV rms for the 115 kV insulators and 200 kV for the 230 kV insulators. The shank temperature of the insulator under test was measured at the ends and middle sections of the insulator immediately prior to applying the voltage. The voltage was then applied for a duration of 15 mins after which the insulator was de-energized and the temperature measurement repeated. In order to pass the test, the insulator had to support the applied voltage for the 15 min period without breakdown or supply overcurrent trip, and the temperature increase at any location along the insulator shank had to be less than 10 ºC during the 15 min hi-pot test. Failure to meet these requirements meant that water was present at the housing/rod interface signifying a defective housing/rod bond.

Seven of the forty-four insulators tested failed to meet the pass requirements. All seven were 230 kV K-Line insulators. The details of the insulators failing the test are given in Table 4-2.

Table 4-2
Insulators failing the water vapor ingress test

Insulator #	Voltage	Manufacturer	Manufacture Date	Visual Comment
53	230	K-Line	1999-11-25	
55	230	K-Line	1999-11-25	Power arc damage
58	230	K-Line	1999-11-25	
61	230	K-Line	1999-11-25	
78	230	K-Line	2000-03-02	
81	230	K-Line	1995-11-23	Significant Rubber Cracking at Line End. Donut corona ring.
84	230	K-Line	1995-11-23	Line End Shed Severe Cracking. Rod exposed at line end. 4 in donut ring

Examination of the data in Table 4-2 shows that of the 7 insulators which failed the test, 2 had significant rubber cracking at the line end housing, with one of these two showing exposed rod. One of the of the failed insulators had been exposed to a flashover and power arc. It is recognized that these 3 insulators had or may have had compromised sealing systems. This leaves 4 insulators (all of which had 8-inch corona rings) which failed the test with no mitigating circumstances. All 7 of the insulators identified in Table 4-2 were quarantined and will be subjected to further tests intended to identify the root cause of failure.

4.5 Moisture Penetration Test of the End-fittings

All of the insulators with the exception of those failing the water vapor ingress test were subjected to end-fitting moisture penetration tests. This test is described in clause 5.7.3.2 of CSA 411.4-2010.

The end fitting moisture penetration test was performed as follows:

- Both ends of each insulator were cut from the insulator length approximately 20 cm above the metal end fittings.
- Each insulator end was submerged to a depth of at least 50 mm above the end fitting in dye
- composed of 1 g of fuchsine in 100 g of methanol for 15 min.
- At the end of the 15 min period, each insulator end was removed from the solution and wiped dry.
- The end fittings were removed from the fibreglass rod and visually examined for evidence of dye penetration through the end-fitting seal.

Evidence of dye on the core rod or interface constituted failure of the insulator to pass the test.

All but 3 of the insulators (insulators 5, 80, and 87) passed the end-fitting moisture penetration test. Insulators 5 and 87 are 115 kV K-Line insulators which have been in service since 1991 and 1992 respectively. Insulator 80 is a 230 kV K-Line unit which utilized a 4-inch donut corona ring and showed extensive line-end rubber housing erosion and had a 4-inch length of fiberglass rod exposed from the top of the end fitting up.

The moisture penetration tests confirmed the visual observation that the secondary seal at the line-end fittings of a number of the NGK insulators installed without corona rings was compromised although experience of large quantities of NGK units removed from the field by EPRI has indicated that this not a significant issue. Figure 4-13 shows an example of this.

Figure 4-13
Dye entering the end fitting through a compromised secondary seal but not reaching the fiberglass rod

As the figure shows, the dye penetrated into the end-fitting through the secondary internal seal. The primary seal remained sound preventing the dye from reaching the fiberglass rod. This was observed on a significant number of the NGK insulators installed without corona rings but not on NGK insulators installed with the 8-inch corona rings.

5 ASSESSMENT OUTCOME

The key findings of the assessment are as follows:

Visual inspection showed that:

- The 230 kV K-Line insulators with the 4-inch donut corona ring have an extremely high likelihood of electrical and or mechanical failure due inadequate control of the electric field on the surface of the rubber housing at the line end. The rubber housing at the line end of these insulators has been severely eroded leading to exposure of the fiberglass rod. Such exposure of the rod will result in either mechanical or electrical failure with a high probability of the insulator parting and causing a conductor drop.
- The 230 kV NGK insulators installed without corona rings are showing signs of serious deterioration of the line-end rubber housing and deterioration of the secondary seal. As such, they are considered to have a high risk of failure.
- The 230 kV NGK insulators installed with 8-inch corona rings are undergoing rubber housing damage at the line end due to the poor design of the mounting portion of the ring. Currently this deterioration does not appear overly serious, but it is not known how quickly the housing deterioration will progress. In the EPRI aging chamber and at one EPRI member utility site this deterioration did result in eventual failure.
- The 230 kV Ohio Brass insulators installed without corona rings are showing rubber and seal deterioration at their line-end fittings. However, in EPRI's experience, the risk of failure can be significantly mitigated by retrofitting corona rings.
- The 230 kV Sediver insulators (all equipped with 11-inch corona rings) are not showing any significant external deterioration
- The 230 kV K-Line insulators installed with 8-inch corona rings do not show any significant signs of deterioration.
- The 115 kV K-Line dead-end insulators do not show any significant visually observable ageing even though they have been in service for 27 years,

Hydrophobicity testing showed that:

- The silicone insulators which have not been damaged due to excessive fields on the rubber surface remain hydrophobic.
- The non-silicone insulators show, as expected, a low degree of hydrophobicity.

Dye penetration testing showed that:

- Each of the insulator groups with the exception of the Ohio Brass insulators had a single insulator unable to meet the dye penetration test requirements.

Water vapor ingress testing showed that:

- Seven 230 kV K-Line insulators exhibited low resistance along their length after humidity conditioning. Of these seven, three had damage from power arcs and housing erosion which may explain their failure. The remaining four (all of which had 8-inch corona rings) will be further examined to determine the root cause of failure.

End-fitting moisture penetration tests showed that:

- All but three insulators passed the test. Of the failing three units, two have been in service for 26 and 27 years, and the third had major line-end rubber erosion and rod exposure.

6 RECOMMENDATIONS

The following recommendations are made based on the assessment outcome. They are listed in order of importance:

All 230 kV K-Line insulators fitted with 4-inch donut corona rings should be removed from service as soon as possible since they pose a proven risk of immediate failure.

All the 230 kV NGK insulators installed without corona rings should be removed from service as they are considered to be at high risk of failure.

All the 230 kV Ohio Brass insulators installed without corona rings should be removed from service.

The 230 kV NGK insulators fitted with 8-inch corona rings should be monitored for continuing degradation by removing samples periodically for inspection.

The seven 230 kV K-Line insulators which failed the water vapor ingress test should be subjected to additional testing followed by dissection to quantify the degree of concern which should be associated with their failing the water vapor ingress test. This type of issue is generally associated with poor bonding between the housing and the rod and is often a batch problem. Until the issue is understood, these insulators should not be maintained live without first checking their integrity with the EPRI developed insulator tester.

7 REFERENCES

[1] "Guidance on the Measurement of Wettability," IEC, 2003.62073.

[2] "Field Guide: Visual Inspection of Polymer Insulators," EPRI, Palo Alto, CA, 2015.3002005627.

[3] "Field Guide: Corona Rings for Polymer Insulators – Selection, Inspection and Assessment," EPRI, Palo Alto, CA, 2005.1008741.

[4] "230 kV Accelerated Aging Chamber: Final Condition of Polymer Insulators After Four Years of," EPRI, Palo Alto, CA, 2005.1010250.

A

FAILURE INVESTIGATION OF 230 KV K-LINE INSULATOR WITH SMALL DONUT CORONA RING

Introduction

Hydro One experienced a conductor drop due to the mechanical failure of a K-Line 230 kV suspension insulator. The failure occurred in October of 2016 on tower number 382 of circuit C28C. The failed insulator and the two sister insulators from the same tower were removed and provided to EPRI for inspection. This report summarizes the findings of the insulator examination and provides recommendations based on the findings.

Insulator Examination

Three 230 kV insulators manufactured by K-Line Insulator Company were provided to EPRI for visual examination. The three insulators had been removed from tower number 382 of circuit C28C following the mechanical failure of one of the units.

A photograph of the three insulator is shown in Figure A-1.

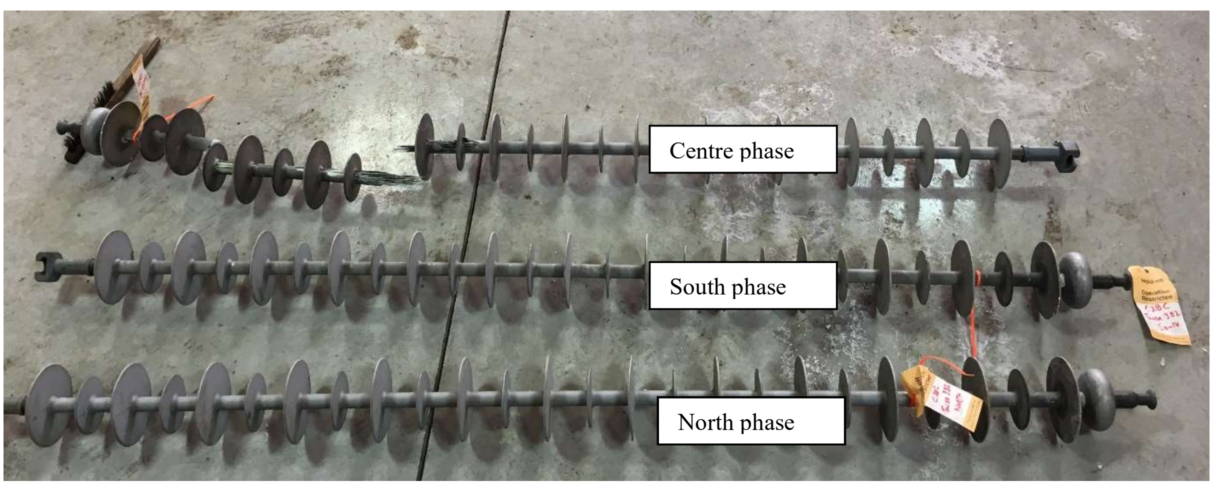


Figure A-1
Insulators provided for inspection

As shown in the photograph, the insulators were equipped with small corona rings at their line ends. The centre phase insulator which had failed mechanically in two locations along its length was severely damaged. The rubber housing was severely eroded and the exposed rod showed extensive tracking due to discharge activity along a significant portion of its length. The extent of the damage is illustrated in the photograph given in Figure A-2. Close ups of the three sections of the failed centre phase insulator are shown in Figure A-3.

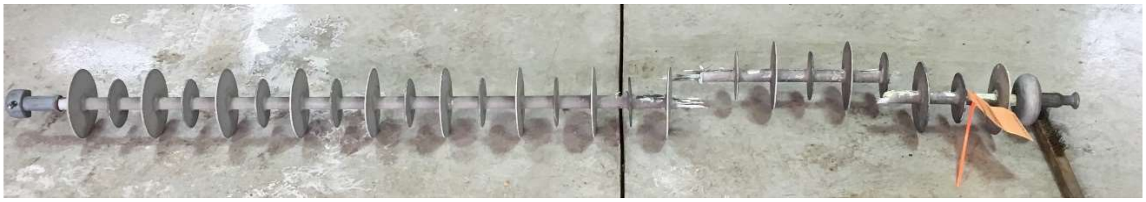
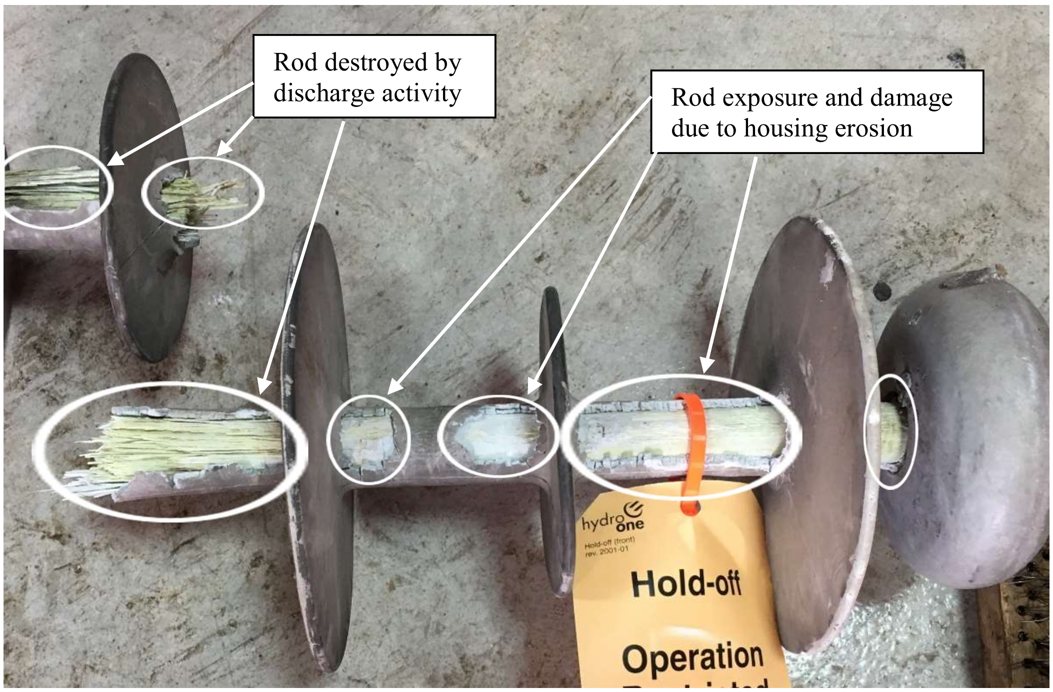
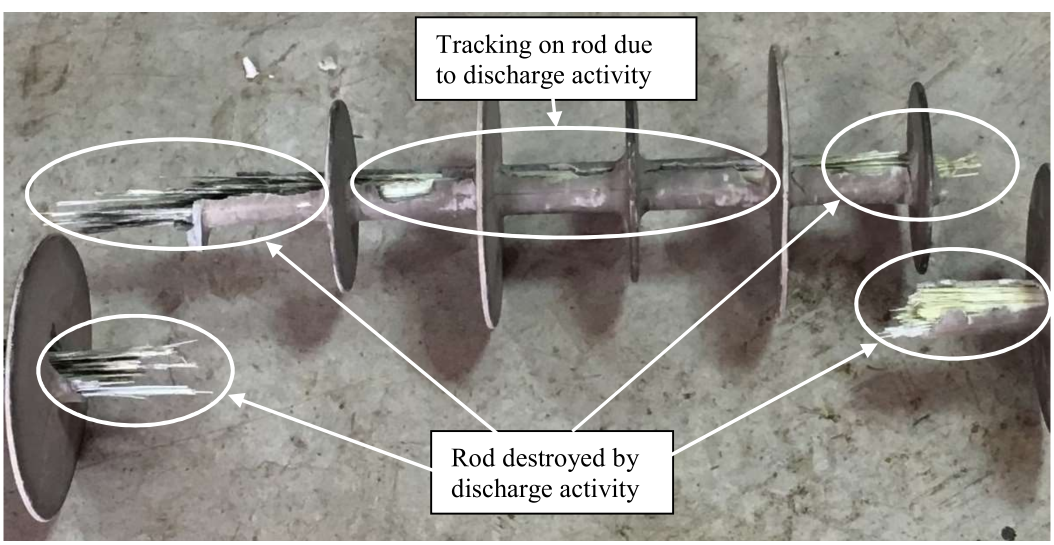


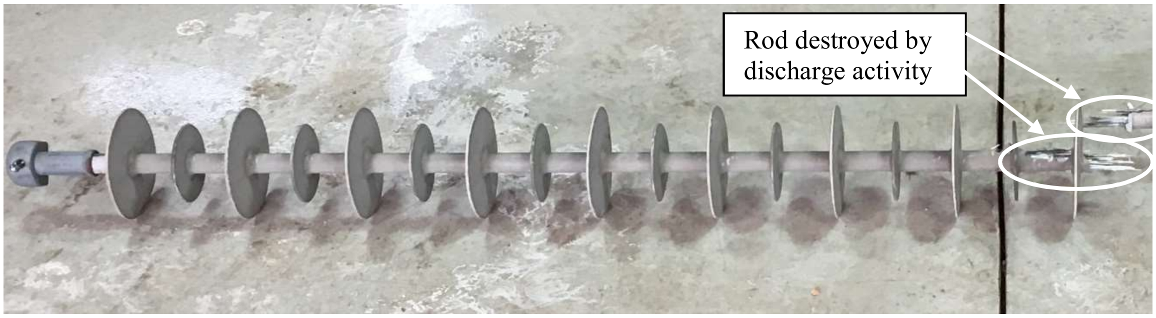
Figure A-2
Failed center phase insulator



(a) Line end section



(b) Middle section



(c) Ground end section

Figure A-3
Close up views of the portions of the center phase insulator

Figure A-4 and Figure A-5 show the south and north phase insulators respectively.

Figure A-4

Figure 4: North phase insulator

Figure A-5
South phase insulator

The south and north phase insulators showed varying degrees of erosion of the rubber housing at their line ends but no visually apparent damage in any other areas. The housing erosion present on the south and north phase insulators is shown in Figure A-6 and Figure A-7 respectively.

Figure 6 shows the extent of housing erosion and rod exposure as seen by rotating the south phase insulator along its axis.

Figure A-6
Housing erosion and rod exposure present on the line-end of the south phase insulator

Figure 7 shows the extent of housing erosion as seen by rotating the south phase insulator along its axis.

Figure A-7
Housing erosion present on the line-end of the north phase insulator

Findings and Recommendations

The center phase insulator failed mechanically due to erosion of the fiberglass rod. The failure was initiated due to inadequate grading of the electric rod at the insulator's line end. Corona discharges on the surface of the rubber housing at the insulator line-end eroded the housing. This lead to exposure of the fiberglass rod and subsequent tracking and burning along the section of rod which had been exposed. In parallel with this, the fact that the rod was no longer sealed from external moisture ingress allowed moisture to penetrate the rod up through its length making the rod partially conductive through tracking. The tracking weakened the rod to the point that the insulator separated resulting in a conductor drop. The sister insulator was damaged and if left in service would have deteriorated to the point of failure through the same mechanism.

It is recommended that any of these insulators be removed from service due to the almost certain probability of catastrophic mechanical failure.

B
230 KV AGING CHAMBER NGK-LOCKE FAILURE

230 kV Aging Chamber NGK-Locke Failure

Andrew Phillips
Project Manager
Transmission and Substations

EPRI

I-string - Failure

- NGK - I-String
  - IB1, Ser number: 3-00334-146 YR- 2000
  - Catalog # 251SS740YJ
- Aging to failure for the NGK are as follows:
  - Mechanical 30574 hrs (1273.9 days)
  - Electrical 22015.3 hrs (917.3 days)
- Unit was installed for 96 aging hours with 4" ring at start of test – then changed to 8" ring
  - NGK supplied TVA with 4" ring
  - Test started 01/24/2001 – 8" ring installed 01/30/2001
  - AJP contacted NGK to clarify appropriate ring recommendations
- Failure appears to be brittle fracture

2

EPRI

NGK Failure – Engagement with Manufacturer

- Proposal accepted by NGK:
  - NGK viewed insulator on 20th September
  - NGK provided information and images of failure
  - NGK provided aging and discharge images
  - Information was provided on Aging Test
  - NGK to provide a list of tests that they would suggest Task Force Meeting
    - Document received prior to TF meeting
  - NGK to provide a presentation at Task Force Meeting
  - NGK to view insulator again at TF meeting

EPRI

Proposed Evaluation by NGK

(1+2) EDX + SEM analysis of broken portion of FRP to detect decrease in aluminum relative to silicon

(3) GC-MS (Gas Chromatography – Mass Spectroscopy) of rubber surface samples from damaged and undamaged areas to see if there is a difference in the presence of small cyclics that indicate depolymerization by heat due to spot discharges. If water drop corona lead to loss of hydrophobicity and then sheeting out of water, it is possible that local spot discharges between water sheets damaged rubber.

(4) FT-IR analysis on the rubber at and around broken portion. FT-IR can check the existence or reduction of CH3 and ATH. It will be more effective to combine with EDX analysis for precise evaluation. It also can determine if damage to rubber was by acid attack

(5) Since the rubber at line end was damaged more on one side than the other, conceptually divide the insulation into two sides (damage portion being one side) then check ESDD to compare hydrophobicity on both sides of insulator along its length and repeat tests 3 and 4 on ground end rubber comparing sides. Maybe one side was more exposed to contamination in chamber, or one side is chemically a little different because of manufacturing process.

(6) Check degree of bonding between FRP and rubber at in region of broken portion

(7) Perform rubber strip check on insulator to determine degree of bonding between FRP & rubber.

(8) Put 2 new NGK insulators in chamber for a month. One with 4" ring and one with no ring, and closely monitor corona. At end of month inspect. It is possible the 4" ring damaged insulator in some manner and may be worse than no corona ring.

Modified insulator with 4" ring installed in aging chamber for X days, change in hydrophobicity and condition observed after test

(9) Test for ph levels on surface of insulators at line end in (8) immediately after wet cycles. Determine if acid is generated and if there are differences in amount of acid in various locations with different rings

(10) Perform 3D analysis on several ring size designs, 4", 8", 9.5" and 11" diameter rings and on different string configurations.

Summarized by AJP

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Failure as Discovered

5

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Condition
22,015.3 hrs

6

EPRI

Failure Site

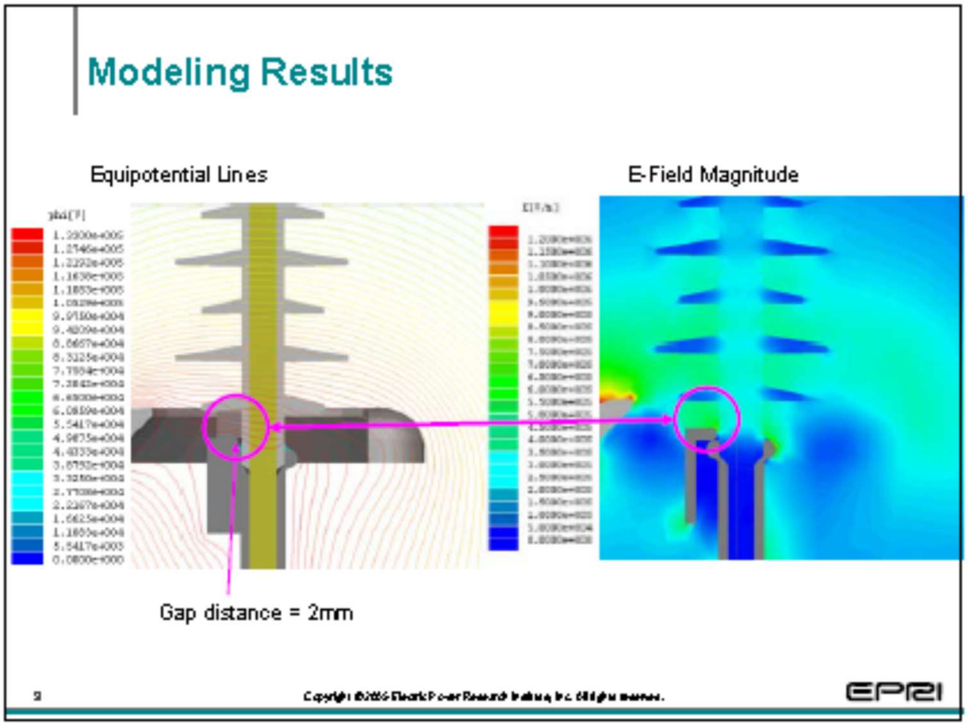
7

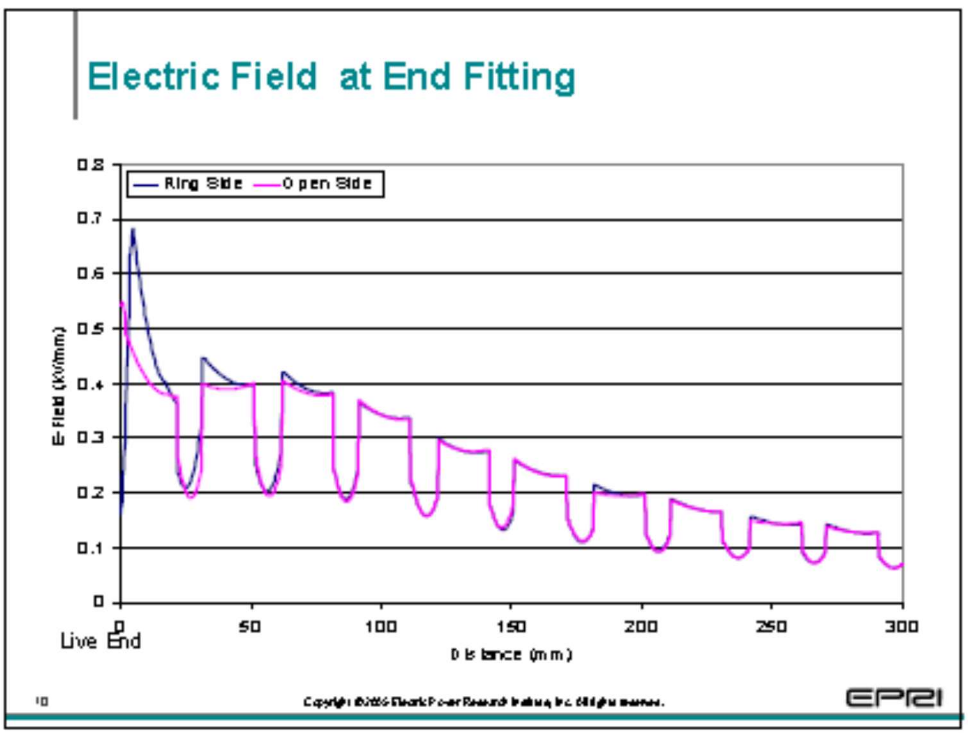
EPRI

Corona Ring Orientation

8

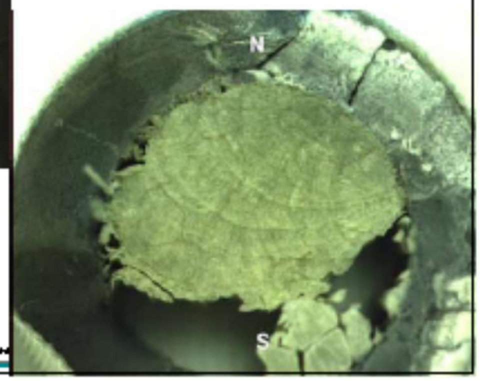
EPRI


Modeling Results
Equipotential Lines
E-Field Magnitude
Gap distance = 2mm
9
EPRI


Electric Field at End Fitting
Ring Side
Open Side
E-Field (kV/mm)
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0
50
100
150
200
250
300
Live End
Distance (mm)
10
EPRI

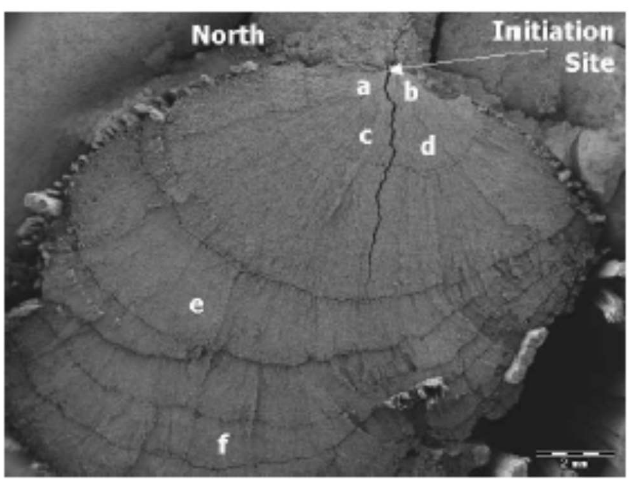
B-6

SEM Analysis



11

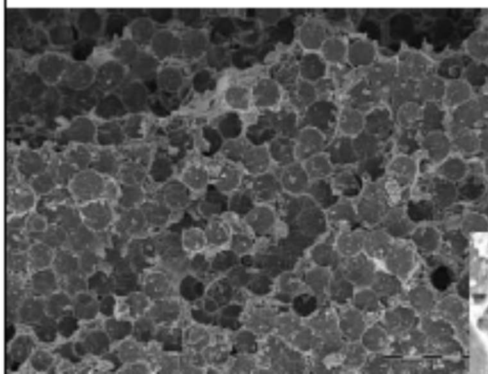
SEM Analysis

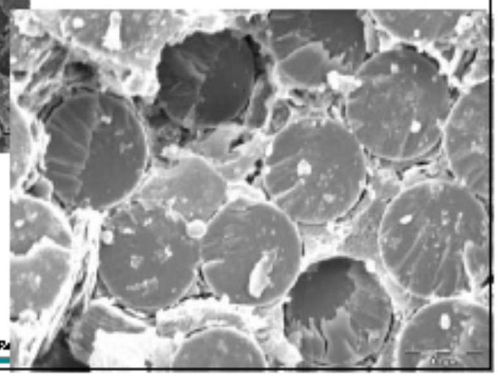


12

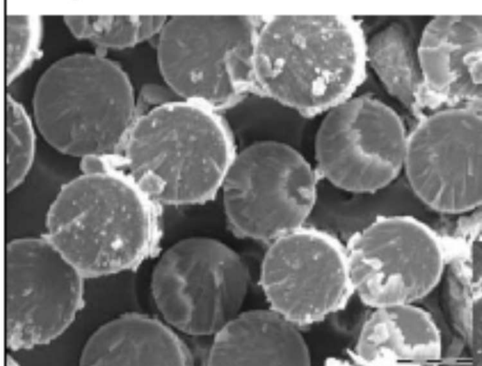
EPRI

Initiation Site "a"



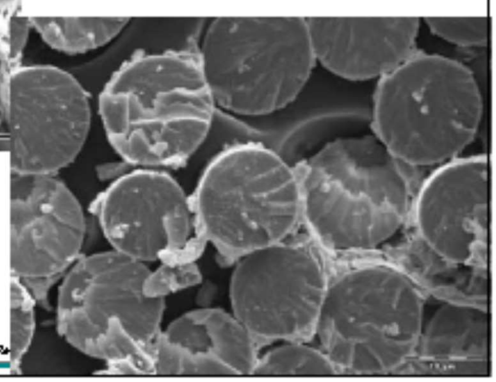


Fracture Sites "c" and "d"

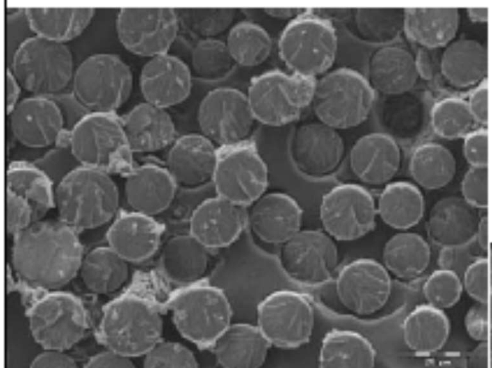


Fracture Site "c"

Fracture Site "d"

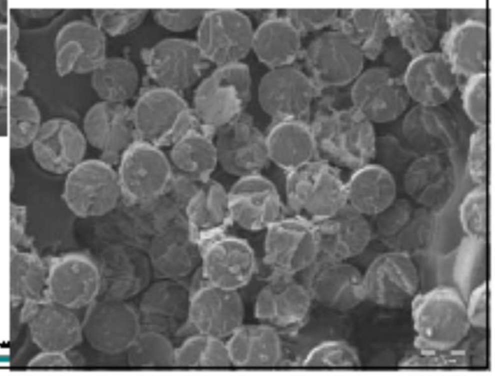


Fracture Sites “e” and “f”

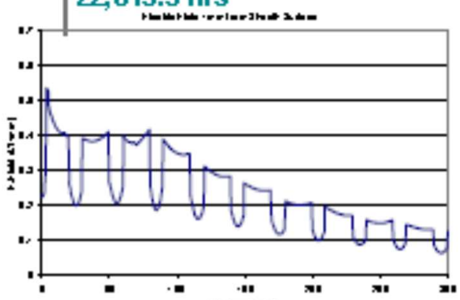


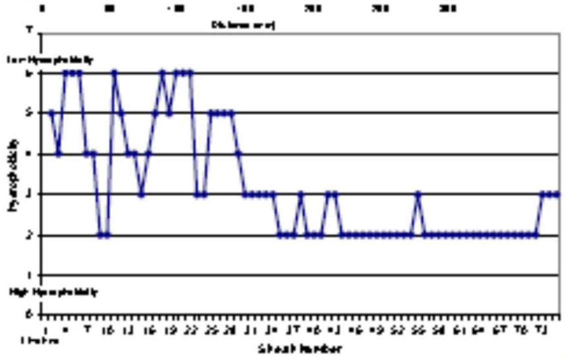
Fracture Site "e"

Fracture Site "f"

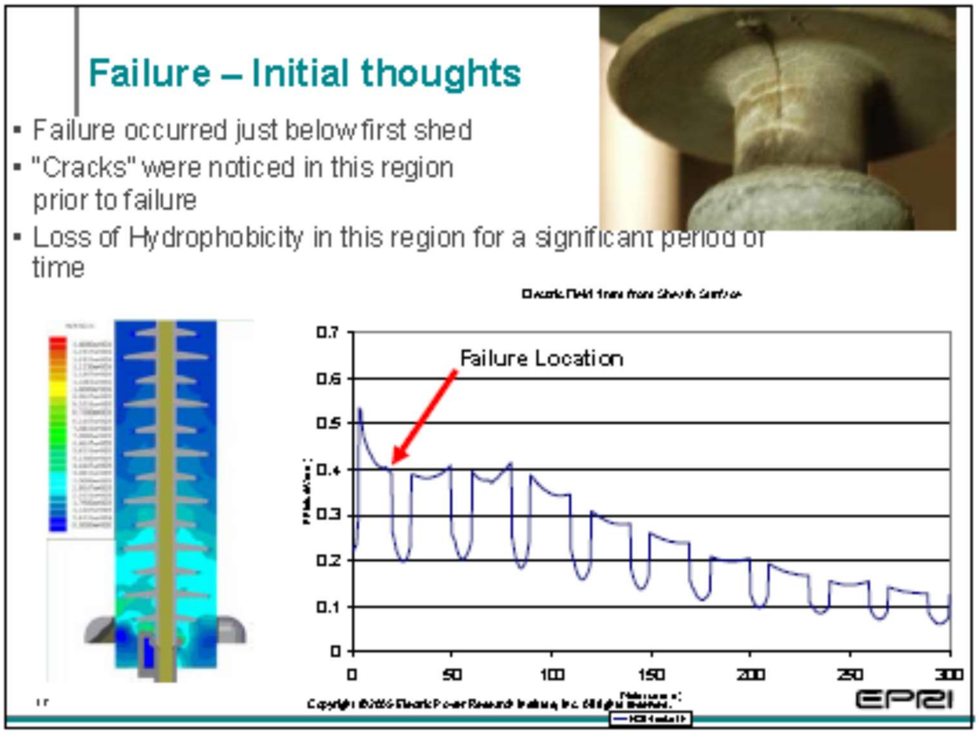


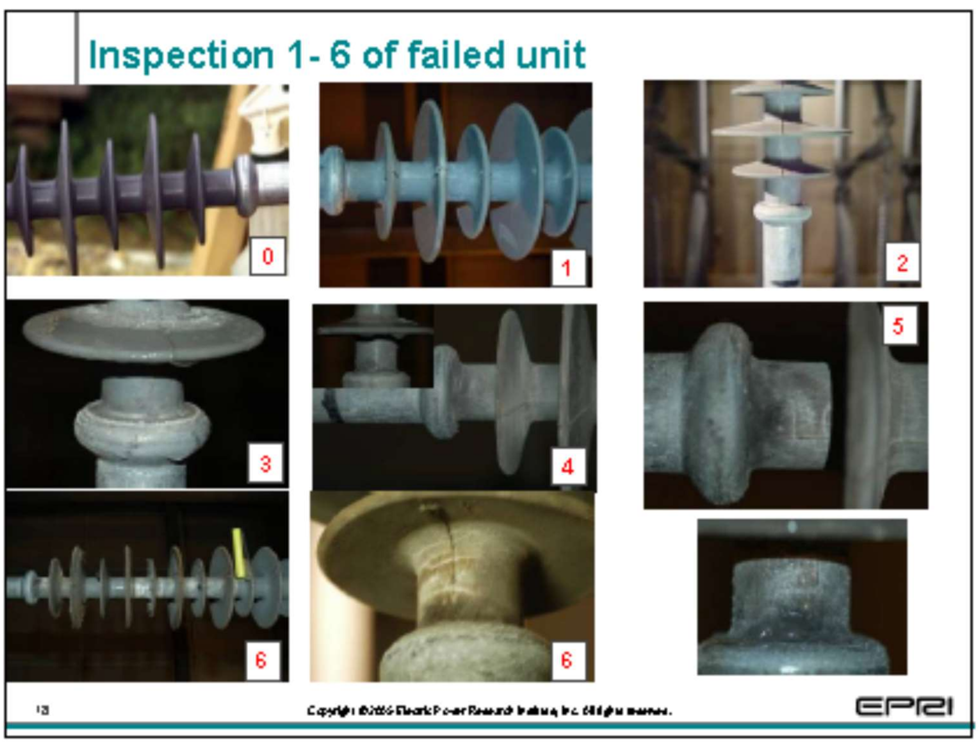
Hydrophobicity
22,015.3 hrs





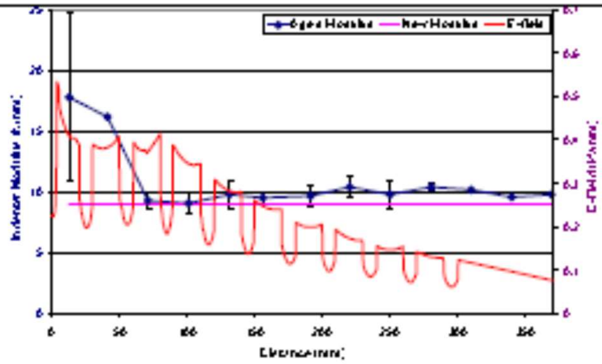
EPRI

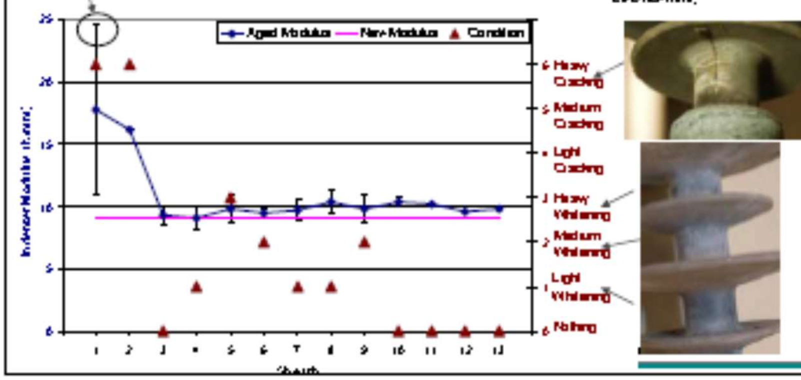

Failure – Initial thoughts
▪ Failure occurred just below first shed
▪ "Cracks" were noticed in this region prior to failure
▪ Loss of Hydrophobicity in this region for a significant period of time
Failure Location
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
50
100
150
200
250
300
EPRI


Inspection 1- 6 of failed unit
0
1
2
3
4
5
6
6
EPRI

NGK-Locke – SIR - Failed 22,015.3 Hrs

No correlation with Hydrophobicity changes was found



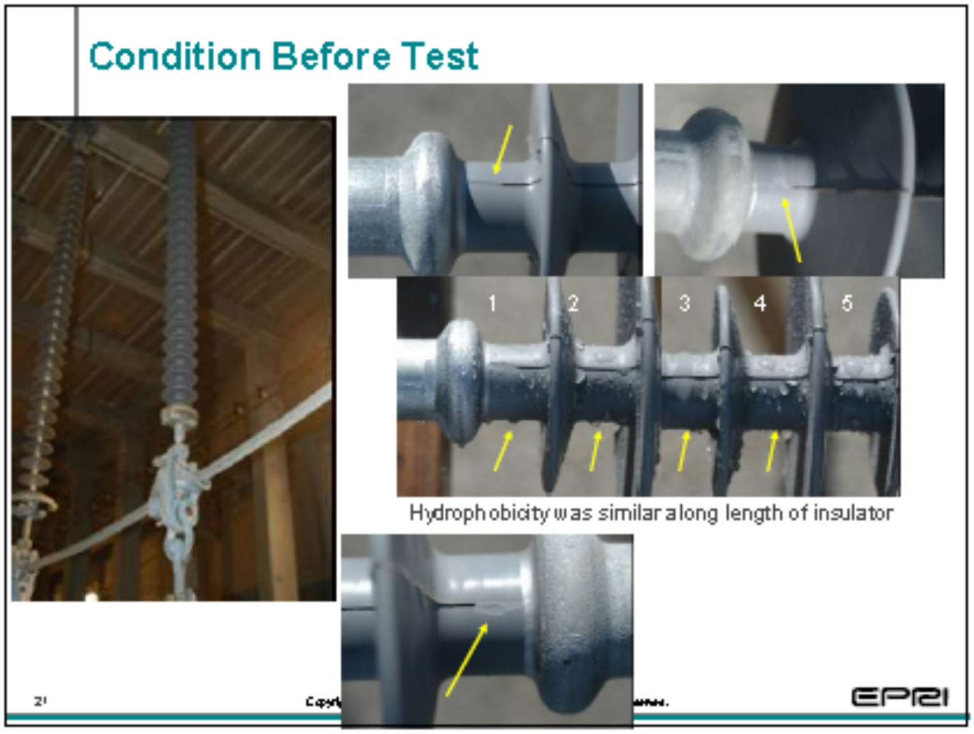


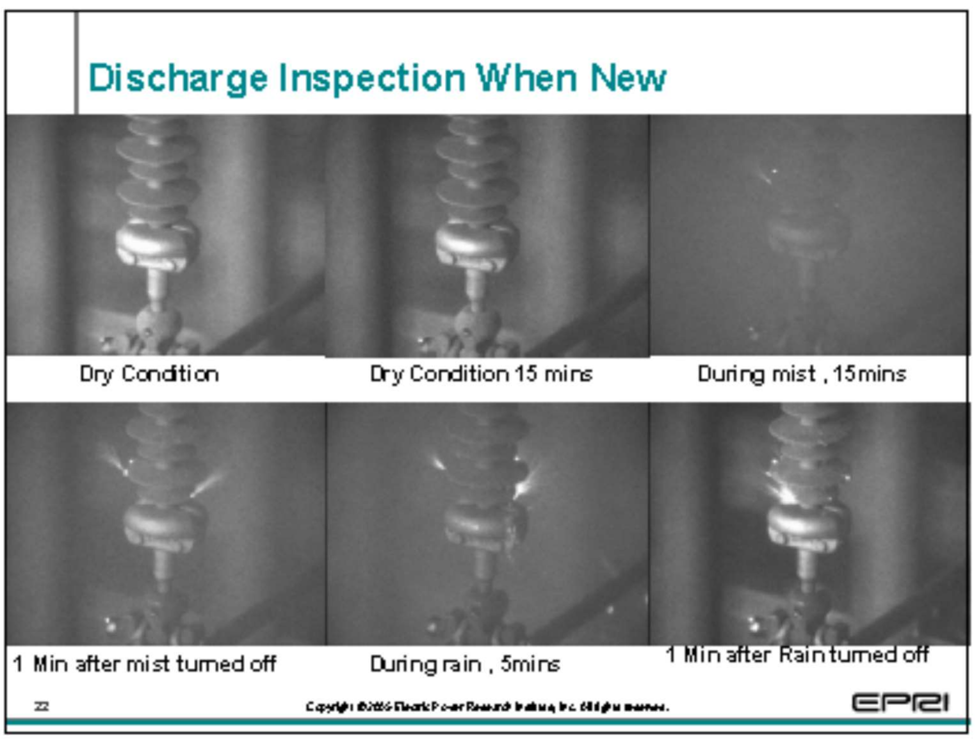
EPRI

Testing of New Unit with 4" ring

- Condition of new unit assessed
  - Hydrophobicity
  - Visual condition
- Installed in Aging Chamber
- Discharge Inspection Performed (viewing angle not perfect)
  - Dry
  - Mist
  - Rain
- Unit removed after 546 aging hours
- Condition of new unit assessed
  - Hydrophobicity
  - Visual condition

EPRI

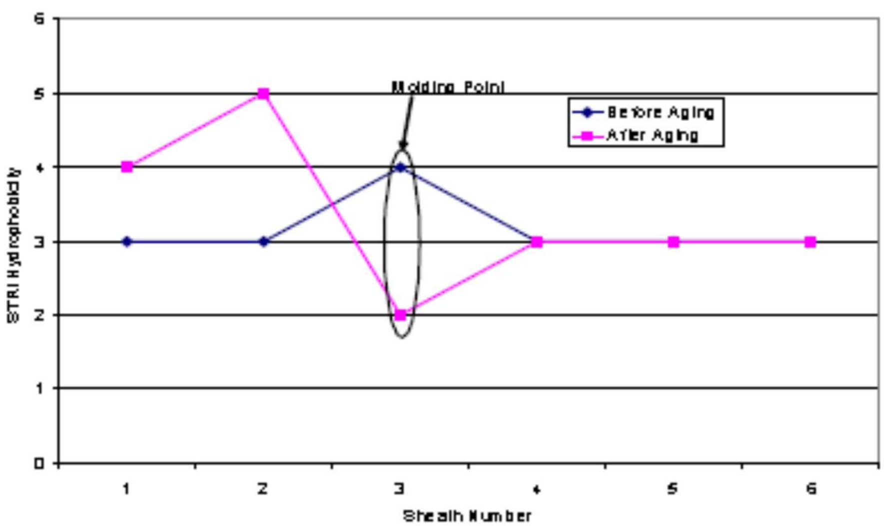

Condition Before Test
1
2
3
4
5
Hydrophobicity was similar along length of insulator
21
EPRI


Discharge Inspection When New
Dry Condition
Dry Condition 15 mins
During mist , 15mins
1 Min after mist turned off
During rain , 5mins
1 Min after Rain turned off
22
EPRI

Condition After 546 Hours of Aging

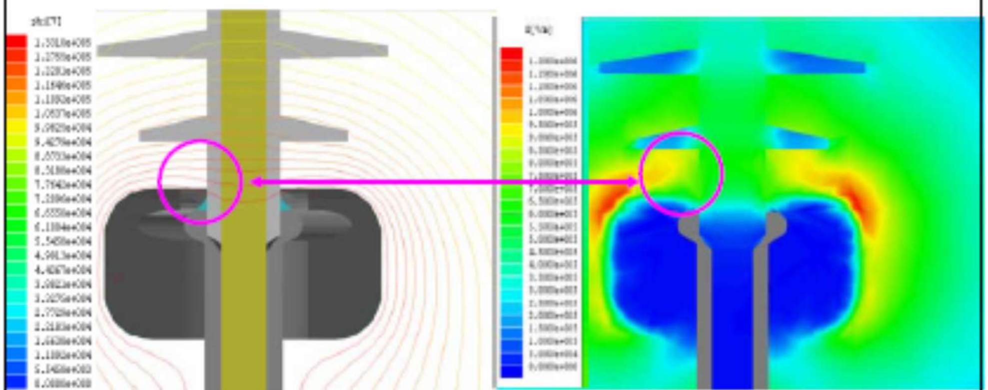
23 EPRI

Hydrophobicity Before and After 546 Hours of Aging



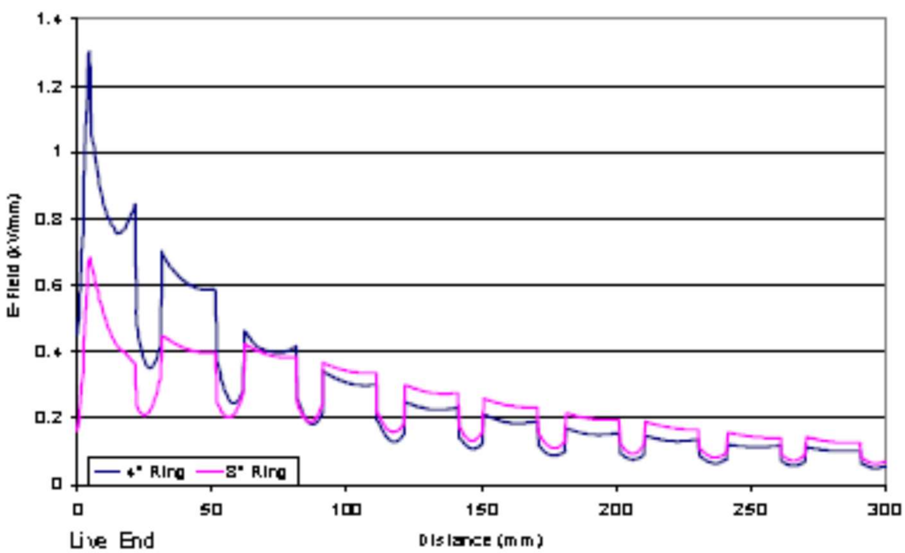
24 EPRI

Modeling Results



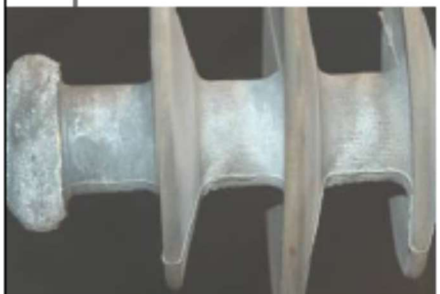
EPRI

Electric Field at End Fitting
4" ring compared to 8" ring



EPRI

Examples of different Insulators from Aging Chamber




Examples from the field – 161kV No Ring, 1998 manufactured, 2005 failure



Examples from the field – 138kV No Ring

Examples from the field –230kV No Ring - Installed 2000, Failed 200505

30

Examples from the field – 138kV No Ring

51

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230 kV insulator installed for 6 years in South Carolina without corona ring

52

EPRI

230kV No ring, high altitude

EPRI

138kV SDG&E Dead end Study

Preliminary Results

Timothy Shaw
Andrew Phillips

EPRI

Background

- Double Circuit Line @ SDG&E
  - 138kV
  - 69kV
- Dead End Structures
  - Steel Pole
  - NGK Polymer Insulators
  - Extra 10" long "Hot Link" (Y-clevis – Ball) between compression fitting and insulator
- Corona Activity Observed on 138kV Circuit
  - Middle phase only

EPRI

What we know

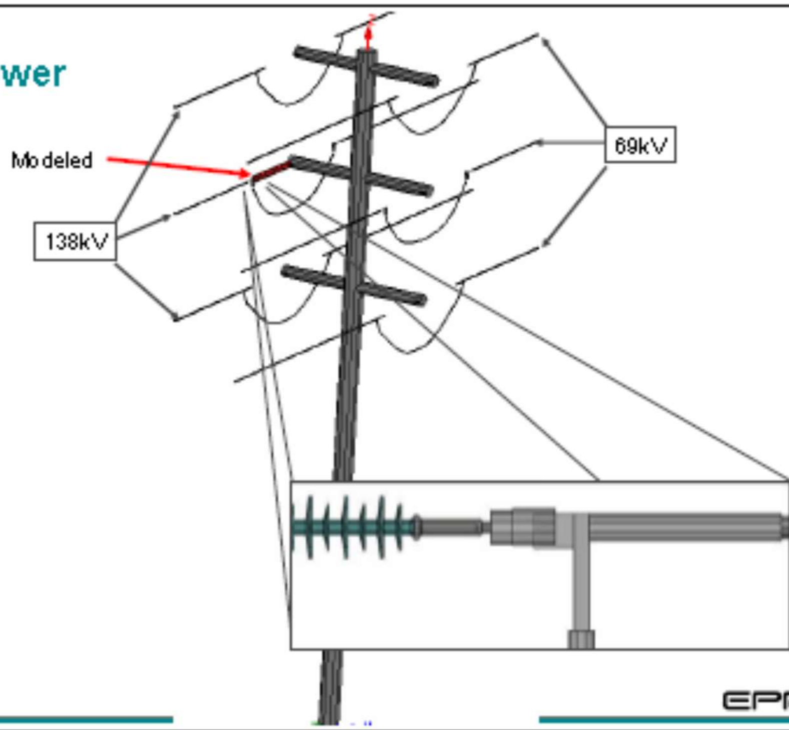
- Continuous dry corona activity degrades polymer material
- High E-field magnitudes on sheath result in non-uniform wetting discharge activity (when wet)
  - Degrades rubber
  - EPRI recommended E-fields <0.45kV/mm
- Dead-end polymer insulators have higher E-field magnitudes
  - Up to 15% higher than suspension (depends on configuration, etc.)
- Center Phase has highest E-fields due to nearby phases
- Extra Hardware such as hotlink increases E-field

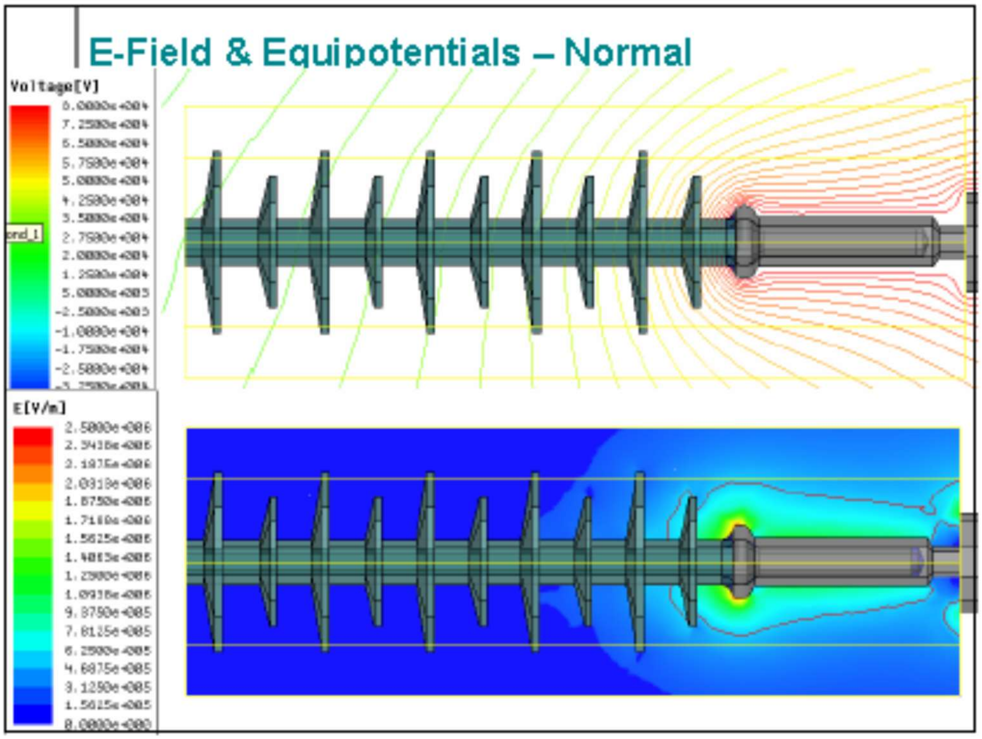
EPRI

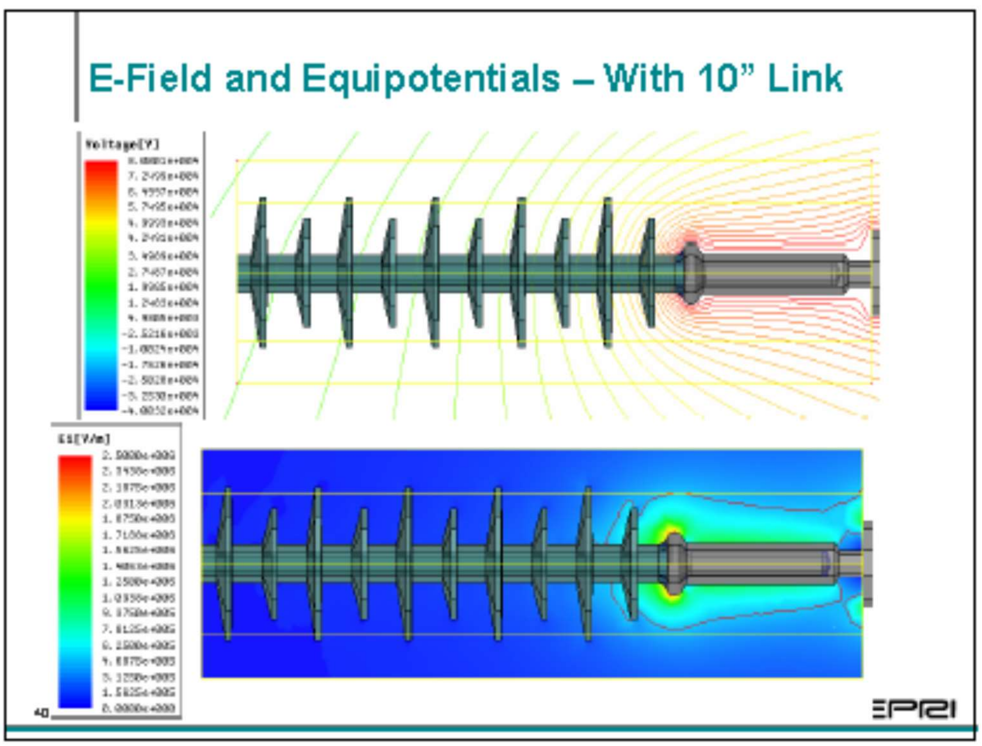
EPRI Involvement

- EPRI identified extra link as an issue while performing an aerial patrol on an unrelated project
- EPRI and SDG&E performed a corona inspection under dry conditions
  - Observed corona under dry conditions
  - No observations under wetting conditions
- E-field modeling
  - Without hotlink
  - With hotlink
  - Center phase
  - First order model

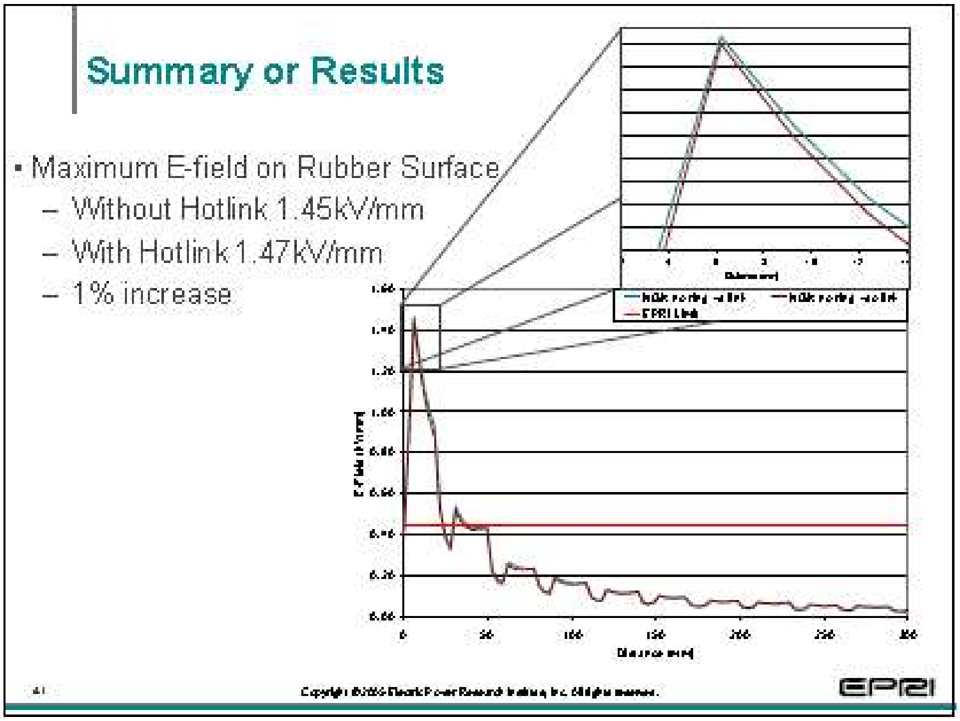
Tower




E-Field & Equipotentials – Normal
Voltage[V]
E[V/m]


E-Field and Equipotentials – With 10” Link
Voltage[V]
40
EPRI

B-21


Summary or Results
• Maximum E-field on Rubber Surface
– Without Hotlink 1.45kV/mm
– With Hotlink 1.47kV/mm
– 1% increase

B-22

Phase 2: CP/COB Porcelain Insulator Population Assessment

Final Report, February 2018

EPRI Project Manager other EPRI staff
J. Kuffel
A. Phillips
F. Bologna
T. Shaw

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

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ABSTRACT

Hydro One has concerns regarding the condition of in-service porcelain insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) installed between 1965 and 1982. These insulators are installed on 22,000 structures (33,600 Circuit structures). Approximately 10,000 of these structures (15,600 Circuit structures) are situated in locations such as road crossings, railway crossings, public spaces, etc. which Hydro One has assessed as safety critical locations. A decision has been made to replace the insulators on these critical structures over the next several years. Following completion of the critical structure string replacement, a decision on replacement of the insulators on the remaining 18,000 non-critical circuit structures will be made.

In order to assess the risk associated with the pace of replacement for both the critical and non-critical strings, and to assist in structuring the replacement program, the test program described below was carried out. The testing program comprised two phases. Phase 1 was completed in 2016. The phase 1 tests were carried out on 299 insulators removed from a combination of dead-end and suspension strings installed in safety critical locations. Phase 1 testing was intended to provide an expedient assessment of the condition of the in-service insulators in question. The results of Phase1 supported the urgent replacement of COB and CP insulators manufactured between 1965 and 1982 that are installed on critical structures where public safety is at risk. The complete findings of the phase 1 tests are presented in EPRI Report 108294, “Results and Analysis of Phase 1 Insulator Tests Performed in Support of Hydro One Insulator Replacement Program”, issued on August 19, 2016.

While Phase 1 quickly quantified the immediate magnitude of the existing problem, its limited test regimen could not generate data usable for estimating the continued rate of deterioration or remaining life of the insulator population. Phase 2 of the project focused on expanding the test program used in phase 1 by incorporating additional tests based on a CIGRE recommended procedure intended to assist utilities in determining when large populations of in-service insulators have reached their end of life and should be removed from service. The tests also included steep front puncture tests.

The Phase 2 results provided overwhelming evidence to support taking immediate action to mitigate the risk to the safety and reliability of Hydro One’s transmission system. The key recommendation made is that the population of defective COB and CP insulators installed between 1965 and 1982 be removed from service as soon as practically possible.

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1
INTRODUCTION

Transmission line insulators are required to perform two basic functions. They must provide mechanical support for overhead conductors and they must provide electrical isolation between the energized conductors they support and the grounded towers to which they are attached. It is recognized throughout the industry, that both the electrical and mechanical characteristics of line insulators manufactured between the late 1960's and early 1980's by Canadian Porcelain (CP) and Canadian Ohio Brass (COB) deteriorate significantly faster than other comparable insulators due to cement expansion as described in References [1] and [2].

Porcelain line insulators are specified in terms of their combined mechanical and electrical (M&E) strengths. For example, an insulator with an M&E rating of 36 kips (1 kip = 1,000 lbs.) is designed to withstand an applied tensile load in excess of 36 kips without mechanical or electrical failure. Mechanical failure is defined as a physical breakage of the insulator while electrical failure is defined as cracking of the insulator's porcelain body in the area between the cap and the pin which results in a significant reduction of the insulator's dielectric strength. Both international and Canadian standards specify test procedures and minimum acceptable performance requirements for M&E testing of new insulators.

Hydro One has concerns regarding the condition of in-service CP and COB porcelain insulators installed between 1965 and 1982. These insulators are installed on 22,000 structures (33,600 Circuit structures). Approximately 10,000 of these structures (15,600 Circuit structures) are situated in locations such as road crossings, railway crossings, public spaces, etc. which Hydro One has assessed as safety critical locations. A decision has been made to replace the insulators on these critical structures over the next several years. Following completion of the critical structure string replacement, a decision on replacement of the insulators on the remaining 18,000 non-critical circuit structures will be made.

In order to assess the risk associated with the pace of replacement for both the critical and non-critical strings, and to assist in structuring the replacement program, the tests described in this document and in Reference 1 were performed on insulators removed from service. The full test program was made up of two phases. The results of phase 1 are presented in Reference [3].

This report details the findings of phase 2 which comprised testing of approximately 600 insulators removed from a combination of dead-end, suspension, and idler positions. The results of the phase 1 tests, performed in 2016, were intended to expediently characterize the degree of urgency with which the insulator replacement at safety critical locations should be carried out based upon a snapshot in time of the condition of the phase 1 sample of insulators. Phase two of the testing was performed in 2017. Those tests were carried out on over 600 insulators. The intent of the phase 2 tests was to supplement the phase 1 data and to attempt to provide data on the rate of deterioration of the insulator population, which can be used to infer an estimate of their remaining life. This information will be used by Hydro One to optimize the overall replacement program with respect to the risk of in-service failure.

The project utilized the Kinectrics facility in Toronto for the performance of the testing under the direction of EPRI. Analysis of the results was performed by EPRI.

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SUMMARY OF PHASE 1 TEST PROGRAM

The goal of the Phase 1 tests was to provide a snapshot of the “as-removed” electrical and mechanical condition of the insulators. Each of the insulators removed from service were subjected to the following tests:

1. Each insulator was checked using a 10-kV Megger.
2. Each insulator was subjected to an applied ac voltage of approximately 60% of its rated flashover voltage for a period of 1 minute.
3. Each insulator was subjected to a destructive M&E (Mechanical and Electrical) test to determine its ultimate electrical and mechanical failing load.

Test 1 was used to identify units which were fully punctured and virtually short circuited internally. Test 2 was used to identify those insulators which were partially punctured and would fully puncture under an applied voltage which is lower than the unit’s external flashover voltage. Test 3 was used to generate data describing the insulators’ ultimate mechanical and electrical strength under tensile load.

The results of the phase 1 tests are summarized in Figure 2-1.

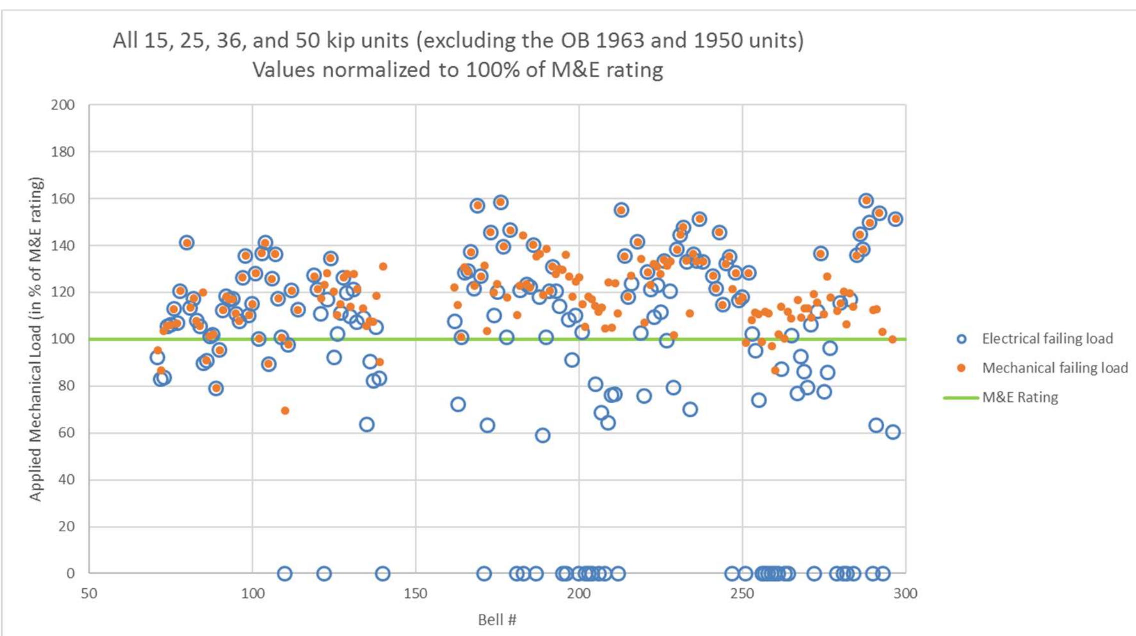


Figure 2-1
Normalized M&E test results from phase 1 testing

As can be seen from the data in Figure 2-1, a large proportion of the insulators tested (37%) failed electrically or mechanically at loads below their rated M&E strength. There was a significant number of punctured insulators (electrical failing load of zero), and the test data showed a large variation in failing loads which would not be expected for a healthy insulator population.

The condition of the Hydro One insulators was assessed through benchmarking to EPRI and public domain test data. This benchmarking data was obtained through testing of similar vintage insulators which had been in service for a comparable duration under similar field conditions. The performance of the Hydro One and the benchmarking insulators was also compared to current and historic requirements for new insulators.

The test results presented an initial snapshot of the condition of the population of defective insulators in-service on Hydro One's transmission system. Although the sample of insulators tested was not sufficient to perform a rigorous statistical analysis upon which to base recommendations, the results strongly suggested that the installed insulator population comprising CP and COB insulators manufactured between 1965 and 1982 had reached or was at least approaching the end of useful life. As such the test data supported the urgent replacement of COB and CP insulators manufactured between 1965 and 1982 that are installed on critical structures where public safety is at risk. Phase 1 included testing of 69 COB insulators manufactured in 1963. The results of those tests showed that the performance of these insulators was below expectations. Historically, Hydro One has been using a manufacturing window of between 1965 and 1982 to identify defective COB and CP insulators. These 69 COB insulators were manufactured prior to 1965 which indicates that the 1965 cut-off year may be inaccurate. Testing additional insulators from the early 1960s was recommended.

3
PHASE 2

The goal of the phase 2 testing was to generate data which can be used to qualify the current condition and continued rate of deterioration or remaining life of the insulator population. As mentioned in the introduction, following completion of the critical string replacement, the course of action to be taken with the insulators on the remaining 18,000 non-critical structures will have to be decided upon. The test results give an indication of the urgency with which suspect insulators installed in non-critical locations should be replaced based upon their as-removed condition and their anticipated end of useful life. As such, the results will provide critical input into the planning and fundamental structuring of the replacement program for the 18,000 non-critical structures.

Phase 2 Insulator Sample

The total number of insulators removed from service and made available for the project exceeded 1,500. They were removed from service in a variety of locations across Ontario. The details of these insulators are given in Table 3-1.

Table 3-1
Details of the 1500 insulators removed from service

Inventory Group	Line Voltage (kV)	Circuit	Structure	Manufacturer	Year of Manufacture	M&E rating (kips)	Number of Units	Colour
1	500	572T	25	COB	1975	50	66	White
2	500	572T	15	COB	1975	50	69	White
3	500	572T	36	COB	1977	36	69	White
4	500	572T	16	COB	1977	36	75	White
5	230		467	COB	1977	36	42	White
6	230			COB/CP	1966	25	78	Brown
7	230	Q11S	B15	COB	1979	25	42	White
8	230	Q11S	B17	COB	1979	25	42	White
9	230	C22J	10 towers	CP/COB	1952	15	540	Brown
10	230	P45, P46		COB	1963	15	84	Brown
11	115	B5C/B6C	21 towers	COB	1978	15	151	White
12	115	X2H	7 towers	COB	1972/1973	15	294	White

As shown in Table 3-1, the insulator inventory included insulators with M&E ratings of 50, 36, 25, and 15 kips. The inventory was divided into groups 1 through 10 based upon their M&E rating, the voltage rating of the circuit in which they had been installed, and their year of manufacture. Any insulators with significant portions of the shed broken off were discounted from the inventory.

From this inventory shown in Table 3-1, 591 insulators were selected for Phase 2 testing. The selection was made so as to have approximately 150 insulators of each strength category. Table 3-2 shows the details of the insulator sample selected for the phase 2 tests. As mentioned above, no insulators with significant shed breakage were chosen for testing.

Table 3-2
Details of the insulators selected for phase 2 testing

Details of Insulators Subjected to Testing										
Kinectrics ID Number From	Kinectrics ID Number To	Inventory Group	Line Voltage (kV)	Circuit	Structure	Manufacturer	Year of Manufacture	M&E rating (kips)	Number of Units	Colour
1	66	1	500	572T	25	COB	1975	50	66	White
67	141	2	500	572T	15	COB	1975	50	69	White
142	210	3	500	572T	36	COB	1977	36	69	White
211	285	4	500	572T	16	COB	1977	36	75	White
328	405	6	230		467	COB/CP	1966	25	78	Brown
406	447	7	230	Q11S	B15	COB	1979	25	42	White
448	489	8	230	Q11S	B17	COB	1979	25	42	White
490	566	11	115	B5C/B6C	21 towers	COB	1978	15	75	White
567	643	12	115	X2H	7 towers	COB	1972/1973	15	75	White

The breakdown according to M&E rating of the 591 insulators used for phase 2 testing is shown in Figure 3-1.

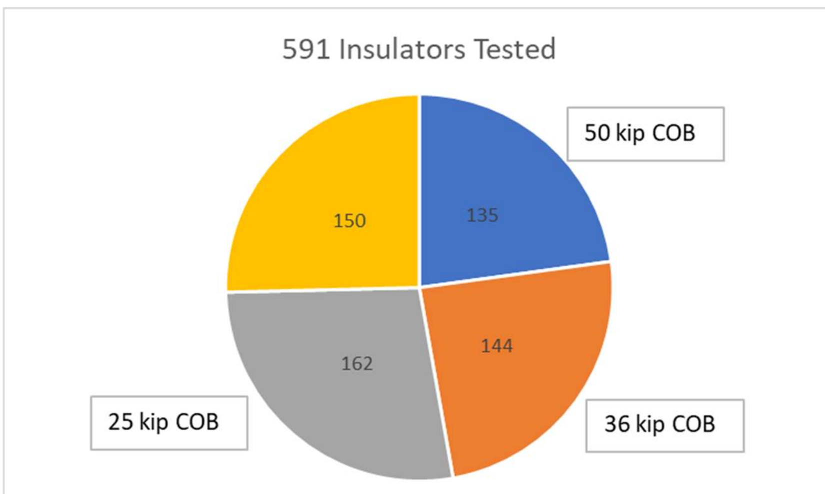


Figure 3-1
Breakdown of phase 2 insulators according to M&E rating

In addition to the insulators described in Table 3-2, 40 further insulators were chosen for limited testing. These insulators, defined in Table 3, were subjected to tests mirroring those performed in phase 1 of the test program. Phase 1 had included testing of 69 COB insulators manufactured in 1963. The results of those tests showed that the performance of these insulators was below expectations. Historically, Hydro One has been using a manufacturing window of between 1965 and 1982 to identify defective COB and CP insulators. Those 69 COB insulators were manufactured prior to 1965 which indicates that the 1965 cut-off year may be inaccurate. The insulators shown in Table 3-3 were manufactured in 1952 and 1963 and the tests were performed as a check on the accuracy of the 1965 to 1982 window historically used to define the period during which defective COB and CP insulators were manufactured.

Table 3-3
Details of additional pre-1965 insulators subjected to limited testing

Rating (kips)	# of samples to be tested	# of samples from each	
		# of samples from each inventory group	Inventory group
15	20	20	9
15	20	20	10

The results of these tests are given in Appendix A.

Phase 2 Test Program

The insulators selected for the phase 2 testing were visually inspected, photographed and catalogued. Following this process, the insulators were subjected to the phase 2 tests.

The primary phase 2 tests can be classified into two categories:

- as-found condition tests
- ageing test followed by evaluation test to infer rate of deterioration and remaining life.

The as-found condition tests were the same tests as those utilized in phase 1 of the project. Those tests included:

- Test 1: Checking each insulator using a 10-kV Megger (600 insulators)
- Test 2: Subjecting each insulator to an applied ac voltage of approximately 60% of its rated flashover voltage for a period of 1 minute (600 insulators)
- Test 3: Subjecting each insulator to a destructive M&E test (270 insulators).

Test 1 was used to identify units which were fully punctured and virtually short circuited internally. Test 2 was used to identify those insulators which are partially punctured and would fully puncture under an applied voltage which is lower than the unit's external flashover voltage. Test 3 was used to generate data describing the insulators' ultimate mechanical and electrical strength under tensile load.

The ageing test comprised:

- Test 4: Subjecting 270 insulators to thermal mechanical cycling tests

Test 4 was used as a conditioning/ageing test intended to accelerate any deterioration in the insulator performance that is related to weather cycles experienced by the remaining in-service insulators. Following this test, the conditioned/aged insulators were subjected to a destructive M&E test which followed the same procedure as Test 3. That M&E test was used to generate data describing the insulators' ultimate mechanical and electrical strength under tensile load following the ageing caused by the thermal mechanical cycling tests (Test 4). Detailed descriptions of tests 1 through 4 are provided in Appendix B.

The use of thermal mechanical cycling (Test 4) to age the insulators is based on the recommendations of a 2006 CIGRE WG B2.03 report [4]. That report outlines procedures developed for estimating the deterioration rate of in-service cap and pin insulators. Their recommended approach is to assess the rate of ageing through the performance of a combined set of M&E and Thermo-Mechanical tests. Cap and pin insulators are known to age through mechanical load and temperature cycling. Thermo-Mechanical testing of insulators comprises subjecting the insulators to a specified load (related to their M&E rated load) and cycling the temperature between two extremes for a specified duration, releasing the mechanical load, and then repeating the process for a specified number of cycles. Although the test is included in ANSI C29.2B [5], IEC 60575 “Thermal-Mechanical Performance Test and Mechanical Performance Test on String Insulator Units” [6], and CSA 411.1 “AC Suspension Insulators” [7], the test parameters vary between the standards. While there are differences between the standards, all three prescribe test conditions which are purposefully severe so as to subject brand new insulators to ageing which they may be subjected to during their expected in-service lifetime. Given that the insulators under test are both relatively old and known to be sub-standard, it was decided to apply a less severe form of thermal mechanical cycling. This approach was taken due to concern that subjecting the test insulators to the standard(s) Thermal Mechanical cycling would result in mechanical damage such as porcelain cracking (resulting in a reduction of the insulators’ electrical strength to practically zero) or physical breakage (separation of the insulator components) during the Thermal Mechanical cycling. The details of the difference in the thermal mechanical cycling parameters recommended in CSA 411.1, ANSI C29.2B, IEC 60575 and those employed during the phase 2 testing are summarized in Table 3-4.

Table 3-4
Thermal Mechanical Test Parameters

	T max	T min	Cycle Duration	# of Cycles	Applied Mechanical Load
CSA 411.1 recommendations	+50 C	-50 C	24 hrs	4	70% of M&E rating
IEC 60575 recommendations	+50 C	-50 C	24 hrs	4	65% of M&E rating
ANSI C29.2B recommendations	+40 C	-30 C	24 hrs	4	60% of M&E rating
Phase 2 test parameters	+50 C	-50 C	24 hrs	2	65% of M&E rating

As seen from Table 3-4, the Thermal Mechanical cycling parameters used in the Phase 2 tests most closely matched the IEC recommendations. T_{max}, T_{min}, cycle duration and applied mechanical load were identical to the IEC recommendations. The only deviation from the IEC procedure was a reduction in the number of cycles from the IEC recommended number of 4 to 2.

In addition to quantifying the effect of thermal mechanical cycling on the M&E strength of the sample insulators as recommended in the CIGRE report, steep front puncture tests were carried out on 60 insulators. Installed insulators are subject to steep front voltage transients generated by lightning. These transients can cause electrical breakdown of the porcelain between the cap and the pin due to the high electrical stress imposed across them. In order to evaluate the susceptibility of the as-received insulators to electrical puncture under simulated lightning voltages and to explore the effect of thermal mechanical cycling on this puncture strength, steep front puncture tests were performed before and after the thermal mechanical cycling described in the preceding paragraphs. Of the total 60 insulators subjected to steep front puncture testing, 30 were steep front puncture tested without thermal mechanical cycling and the other 30 were thermal mechanically cycled and then subjected to steep front puncture tests.

The steep front puncture tests described above are an important factor in the condition assessment because the root cause of the recent conductor drops (past few years) on Hydro One's system has been physical separation of punctured insulators when exposed to power arcs due to string flashover. If the rate of puncture is shown to increase as a consequence of thermal mechanical ageing, the finding will constitute an important input into the urgency with which the COB and CP insulators still in service on non-critical structures should be replaced.

Phase 2 Test Protocol

In preparation for testing, the insulators described in Table 3-2 were allocated to the various test regimen as show in Figure 3-2.

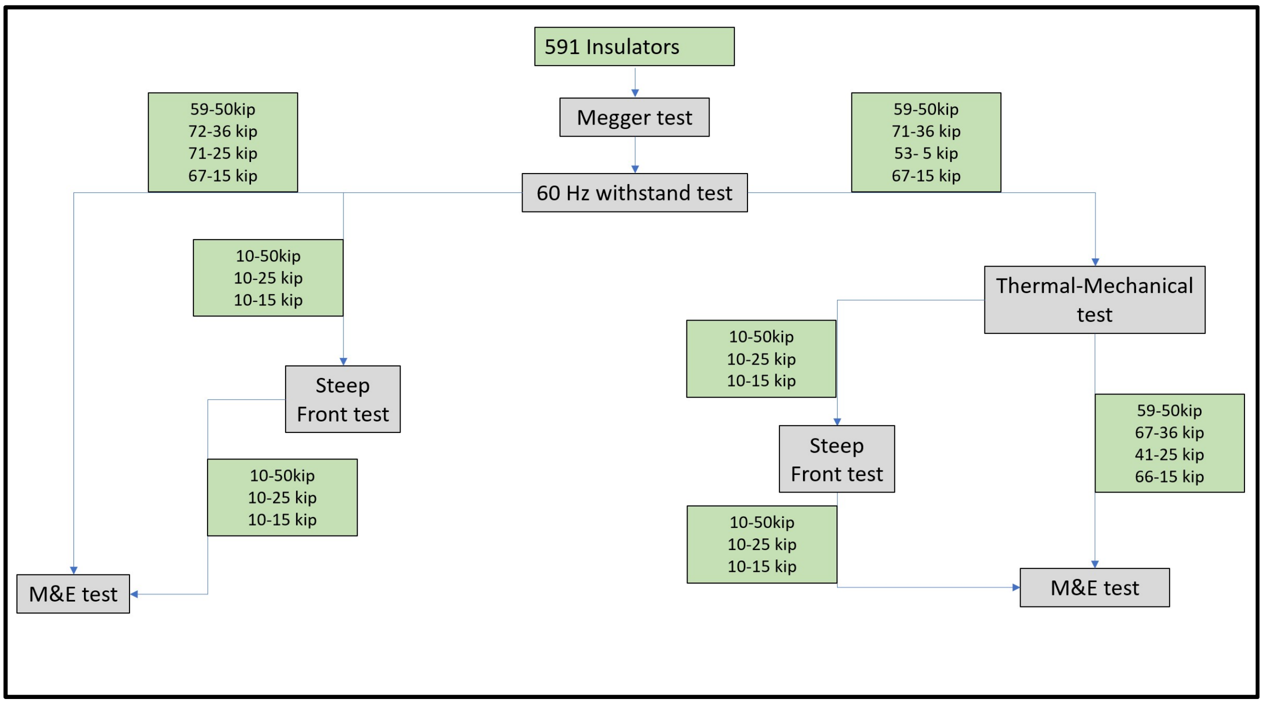


Figure 3-2
Testing protocol

Phase 2 Test Results

Megger and ac Withstand Test Results

The Megger and ac withstand tests (tests 1 and 2) were used to identify the units that were unable to support an applied voltage of 60 kV (approximately 70% of the rated withstand voltage) prior to the application of any tensile load. These insulators are referred to as punctured units because their inability to support voltage is due to a crack or puncture in the porcelain dielectric between the insulator cap and pin. Table 3-5 shows the number and percentage of units that fell into this category. As can be seen from that table, the percentage of punctured bells is low. In fact, the only punctured bells found were three 50 kip units and one 15-kip unit.

Table 3-5
Number of punctured units

Inventory Group	Line Voltage (kV)	Manufacturer	Year of Manufacture	M&E rating (kips)	# of Units	# of Units Failing Megger	# of Units Failing Hi-Pot	Number of Punctured Units	% of Punctured Units
1	500	COB	1975	50	66	2	2	2	3.0
2	500	COB	1975	50	69	1	1	1	1.4
3	500	COB	1977	36	69	0	0	0	0.0
4	500	COB	1977	36	75	0	0	0	0.0
6	230	COB/CP	1966	25	78	0	0	0	0.0
7	230	COB	1979	25	42	0	0	0	0.0
8	230	COB	1979	25	42	0	0	0	0.0
11	115	COB	1978	15	75	0	1	1	1.3
12	115	COB	1972/1973	15	75	0	0	0	0.0

M&E Test Results Without Thermal Mechanical Pre-Conditioning

While the methodology of the M&E testing procedure is described in Appendix B, it is important to note the definition of an insulator's M&E strength. During M&E testing, the insulator is subjected to a steady continuous electrical stress and a steadily increasing mechanical tensile stress. The insulator can undergo two failing modes. It can fail electrically due to the formation of a crack in the porcelain body due to mechanical loading, or it can fail mechanically due to the applied tensile load. The M&E failing load of an individual insulator is defined as the lowest mechanical load at which either electrical failure or mechanical separation of the insulator takes place. Analysis of M&E tests typically comprises fitting a normal distribution to the measured failing load data and comparing the distribution's mean and standard deviation to the insulators' M&E rating and or the maximum anticipated design load under which the insulators operate. In a healthy insulator population, the mean measured M&E strength should exceed the rated load by a given margin related to the measured standard deviation. In the analyses carried out in this report, in addition to above defined M&E failing load, the electrical and mechanical failing loads are examined individually.

As indicated previously, approximately half the insulators were subjected to M&E testing directly after the Megger and 60 Hz withstand tests. The other half of the insulators was subjected to Thermal Mechanical Conditioning followed by M&E testing. This section covers the M&E testing of the insulators not subjected to TMC conditioning. The M&E tests performed on the insulators which had undergone TMC conditioning are presented and discussed in section 3.3.4.

Figure 3-3 through Figure 3-8 show the results of the M&E tests for the individual lots of insulators tested without Thermal Mechanical pre-conditioning.

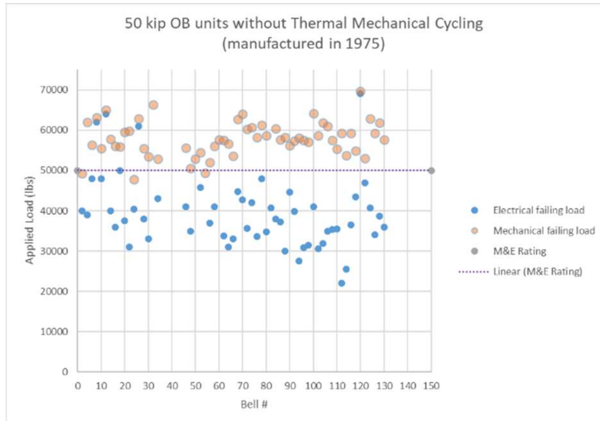


Figure 3-3
M&E test results for insulator lots 1 and 2

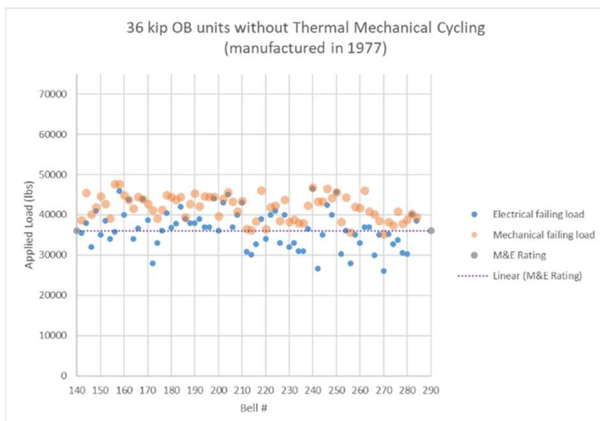


Figure 3-4
M&E test results for insulator lots 3 and 4

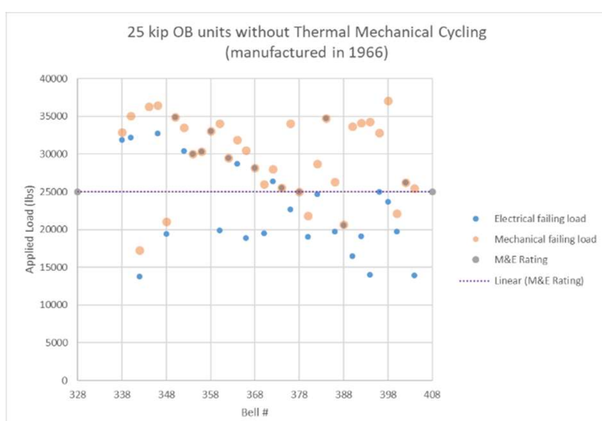


Figure 3-5
M&E test results for insulator lot 6

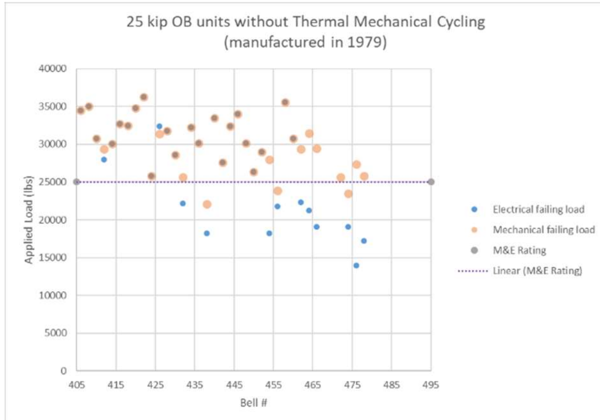


Figure 3-6
M&E test results for insulator lots 7 and 8

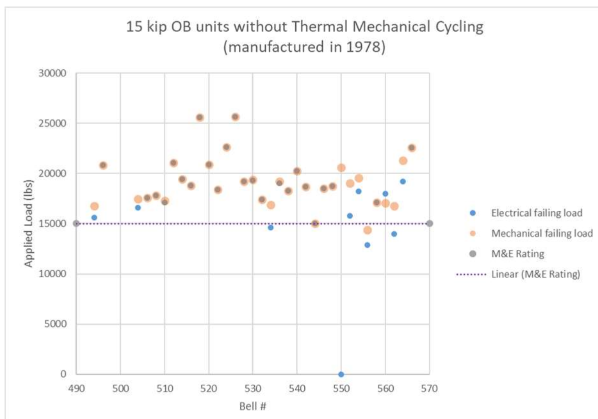


Figure 3-7
M&E test results for insulator lot 11

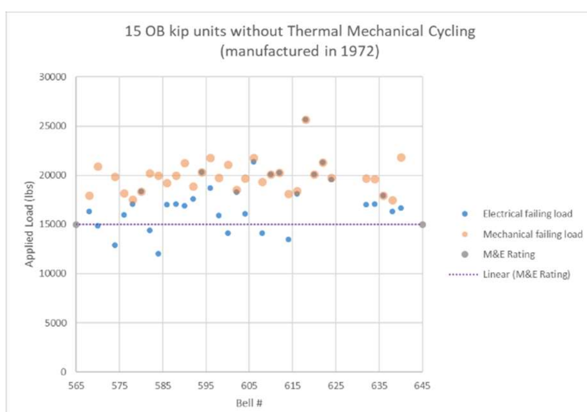


Figure 3-8
M&E test results for insulator lot 12

Examination of Figure 3-3 through Figure 3-8 yields a number of interesting observations. Looking at the graphs it is evident that for all the insulator groups tested:

- there are very few punctured insulators

- the electrical failing loads tend to be below the mechanical failing loads
- the mechanical failing loads appear be close to or above the rated failing load
- the electrical failing loads are generally below the rated failing loads
- while all of the tested insulator groups show electrical failures below the M&E rating, the number of electrical failures and the amount by which they fall short of the M&E rating appears to be greater for the higher rated units. The 50-kip insulator sample shows the highest incidence of electrical failures at loads below the rated M&E load and the greatest difference between the average electrical failing load and the M&E rated load. The number of electrical failures at below the M&E rated load and the difference between the average electrical failing load and the M&E rating both get smaller as the rating of the insulators decreases. These observations are consistent with the exception of the 25 kip units manufactured in 1966 (lot 6). This discrepancy is likely due to the fact that the lot 6 insulators have been in service for some 10 years longer than the other lots.

Table 3-6 shows the results of numerical analysis of the data behind Figure 3-3 through Figure 3-8.

Table 3-6
Percentage of insulators failing to meet their assigned M&E ratings

Data Set	M&E Rating	% failing to meet M&E rating		
-	-	Electric	Mechanical	Combined
50 kip COB units manufactured in 1975	50000	93.2	5.1	93.2
36 kip COB units manufactured in 1977	36000	47.2	2.8	47.2
25 kip COB/CP units manufactured in 1966	25000	52.9	14.7	52.9
25 kip COB units manufactured in 1979	25000	29.7	8.1	29.7
15 kip COB units manufactured in 1978	15000	11.8	2.9	11.8
15 kip COB units manufactured in 1972/3	15000	21.2	0.0	21.2

The data in Table 3-6 confirm the visual observations drawn from Figure 3-3 through Figure 3-8. All of the insulator groups fail to meet their assigned M&E rating with their M&E strength being far lower than rated value. As with the insulators tested in phase 1 of the project, this is primarily due to the extremely poor electrical strength. However, as shown in the table, the mechanical strength of these non-TMC conditioned insulators also falls short of the M&E requirement in all cases with the exception of the 15-kip COB units manufactured in 1972/3.

In comparing the Table 3-6 data to standard requirements, it should be remembered that in addition to the requirements for the calculated mean and standard deviation, most standards require that none of the tested insulators show an M&E failing load below the specified M&E

rating. Table 3-6 shows that the insulators tested fail to meet this requirement with the percentage of insulators having an overall M&E failing load below the required M&E rating varying from a maximum of 93% for the 50 kip units to a minimum of 12% for the 15 kip units manufactured in 1978.

Typical analysis of M&E testing is performed through fitting a normal distribution to the experimental M&E data. Table 3-7 shows the means and standard deviations of the normal distributions which best fit the measured electrical, the measured mechanical, and the measured overall M&E failing load data for the as-received insulators (without TMC).

Table 3-7
Best fit normal distributions of M&E data for units without TMC

Data Set	M&E rating	M&E Statistics (w/o TMC)					
		Mean Electrical Failing Load	Electrical Failing Load Sigma (%)	Mean Mechanical Failing Load	Mechanical Failing Load Sigma (%)	Mean M&E Failing Load	M&E Failing Load Sigma (%)
50 kip COB units manufactured in 1975	50000	39514	23	57850	7	39514	23
36 kip COB units manufactured in 1977	36000	36554	13	41808	8	36554	13
25 kip COB/CP units manufactured in 1966	25000	24542	26	29751	18	24542	26
25 kip COB units manufactured in 1979	25000	28690	24	30595	15	28690	24
15 kip COB units manufactured in 1978	15000	18077	24	19115	13	18077	24
15 kip COB units manufactured in 1972/3	15000	17367	16	19847	8	17367	16

The data in Table 3-7 indicates that for the 50 kip units and for the 25 kip units manufactured in 1966, the mean M&E failing load is below rating. In the case of the 50 kip units, the difference between the measured M&E rating and the rated M&E strength is 20%. For the 25 kip units manufactured in 1966 the difference is 2%. For the remaining groups of insulators, the mean M&E failing load is above the rating, however, with the large standard deviations shown in the table, it can be expected that significant numbers of installed insulators will fail electrically or mechanically under in-service loads considerably below their M&E rating.

Review of the results of the M&E testing (without TMC) shows that:

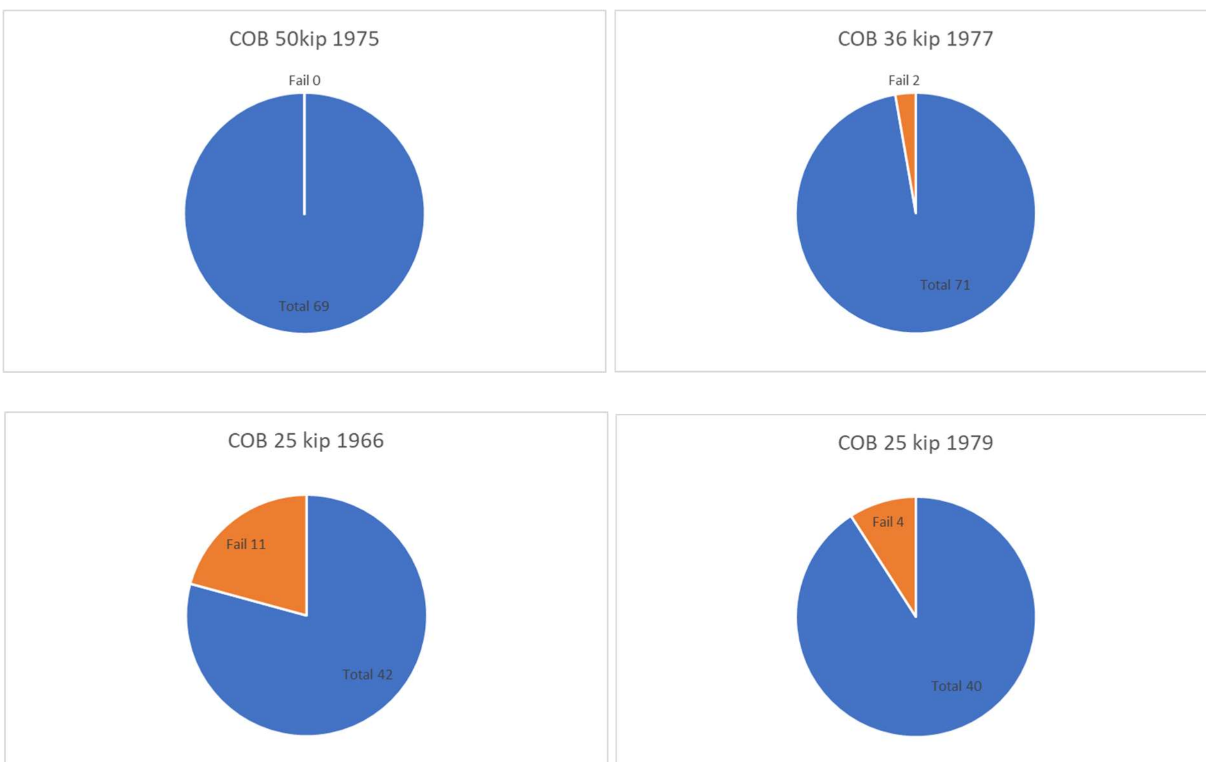
1. a large number of the tested insulators exhibited porcelain cracking (which in essence makes the insulator a punctured unit) at mechanical loads significantly below the insulators' M&E rating.
2. there is a large dispersion in the recorded M&E strengths, the recorded electrical failing loads and the recorded mechanical failing loads.

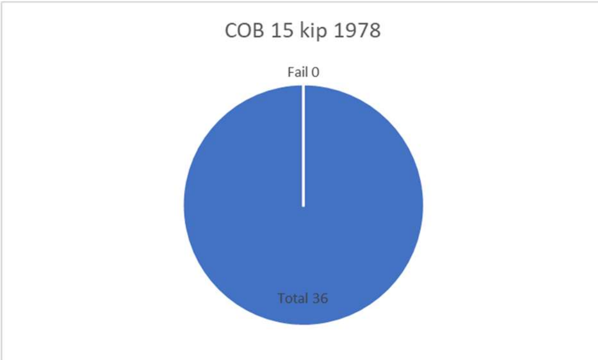
Item 1 above suggests that the number of in-service punctured units will increase as the insulators experience significant mechanical loading events. As explained in the previous section, the quality of insulators is often judged by the standard deviation of the M&E, the electrical, and the mechanical failing loads and by the margin between the recorded mean M&E strength and the M&E rating. Item 2 shows that the differences between the mean recorded M&E strengths and the M&E ratings are coupled with large standard deviations. This combination results in an increased probability of insulator failure at loads below their M&E rating. Both the above observations are atypical for a healthy insulator population.

Thermal Mechanical Cycling

Thermal Mechanical Cycling was performed on approximately half of the sample insulators. The procedure used is described in Appendix B.

A number of insulators physically separated during the TMC and a large number punctured (cracked). Figure 3-9 shows the number of insulators which physically separated. Most of these observed failures occurred during the heating cycle. In addition to the physical separation failures caused by the TMC and summarized in the figure, a number of additional insulators failed due to the recoil action which occurs when one insulator in a string undergoing TMC fails. Since these recoil failures are not directly attributable the TMC, any insulators that failed due to recoil were discounted from the analysis in Figure 3-9.





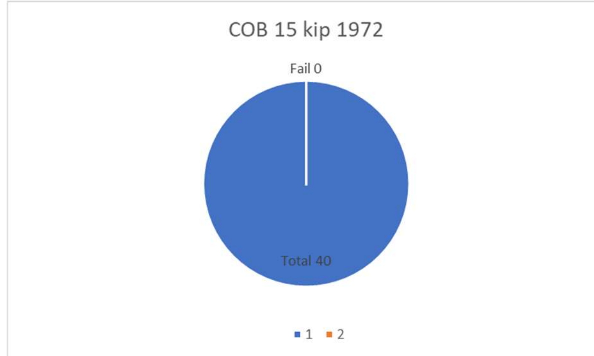


Figure 3-9
Proportion of insulators broken (physically separated) during the TMC.

The number of insulators punctured (cracked) during the TMC is summarized in Table 3-8. As the data show, the TMC induced in a disturbingly large number of punctures (cracks) in the test insulators, with the proportion of insulators punctured varying from a maximum of 90% to a minimum of 23%.

Table 3-8
Proportion of units punctured (cracked) during TMC

Group	Data Set	# of units in test lot	# of units punctured	% of units punctured
1 and 2	50 kip COB units manufactured in 1975	58	52	90
3 and 4	36 kip COB units manufactured in 1977	69	39	57
6	25 kip COB/CP units manufactured in 1966	21	13	62
7 and 8	25 kip COB units manufactured in 1979	31	7	23
11	15 kip COB units manufactured in 1978	33	9	27
12	15 kip COB units manufactured in 1972/3	34	13	38

Effect of Thermal Mechanical Cycling on M&E Strength

This section presents the results of the M&E testing performed on the insulators which had undergone TMC conditioning.

Figure 3-10 through Figure 3-15 show the results of the M&E tests for the individual lots of insulators tested with and without Thermal Mechanical pre-conditioning.

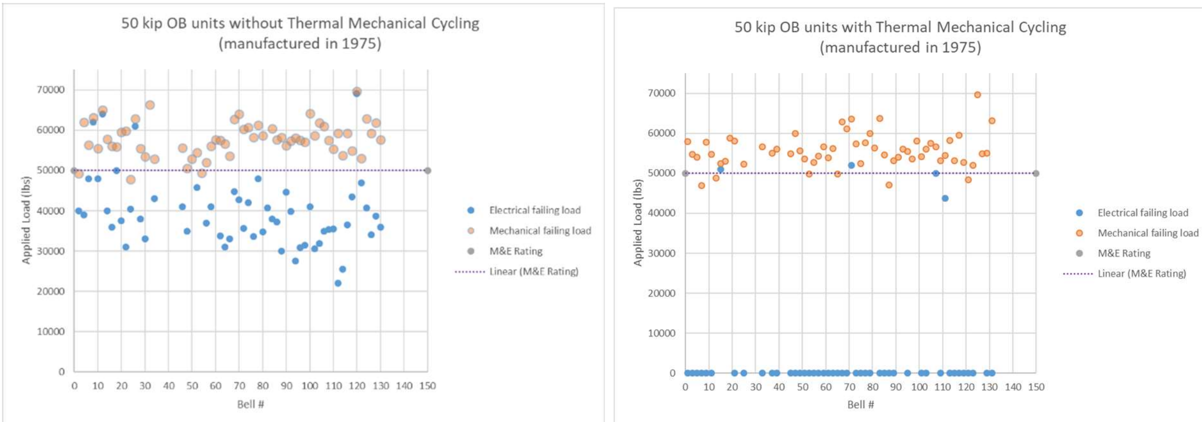


Figure 3-10
M&E test results for insulator lots 1 and 2

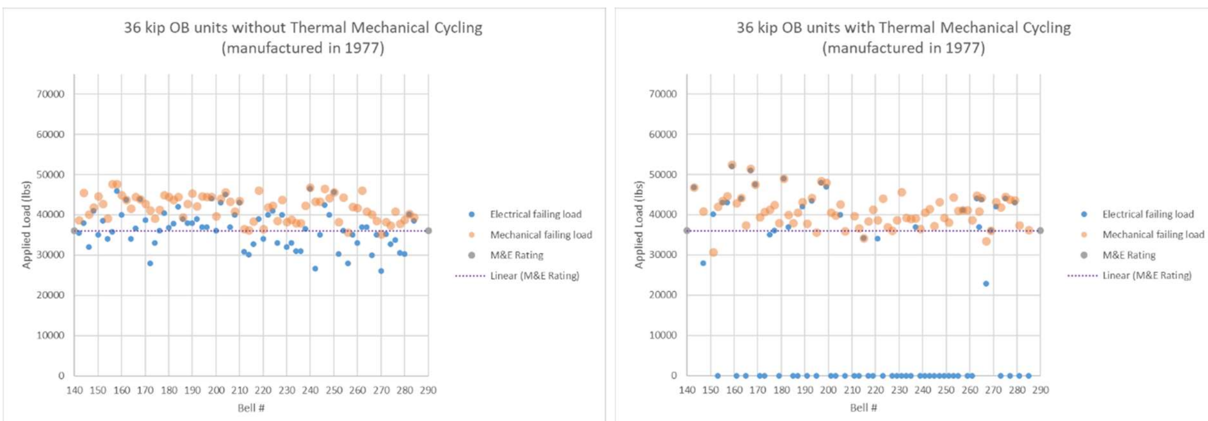


Figure 3-11
M&E test results for insulator lots 3 and 4

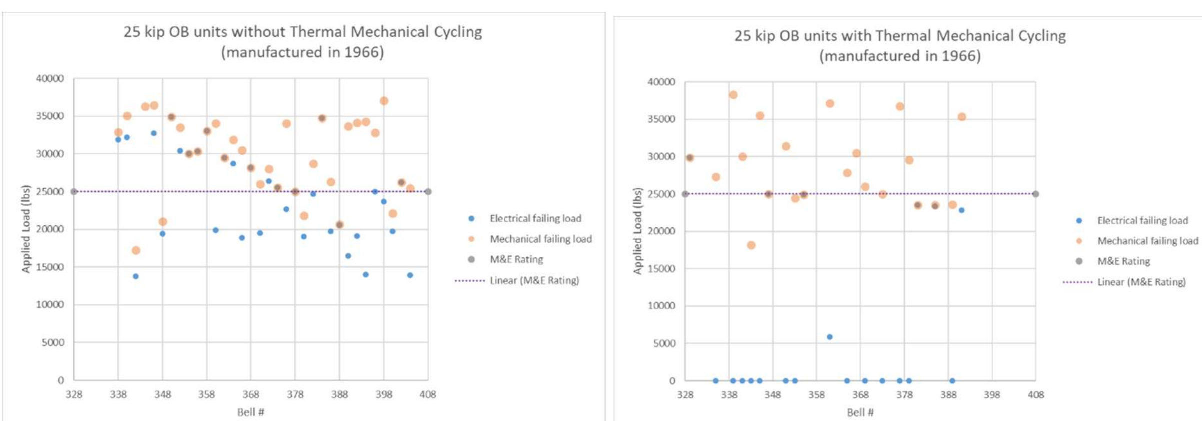


Figure 3-12
M&E test results for insulator lot 6

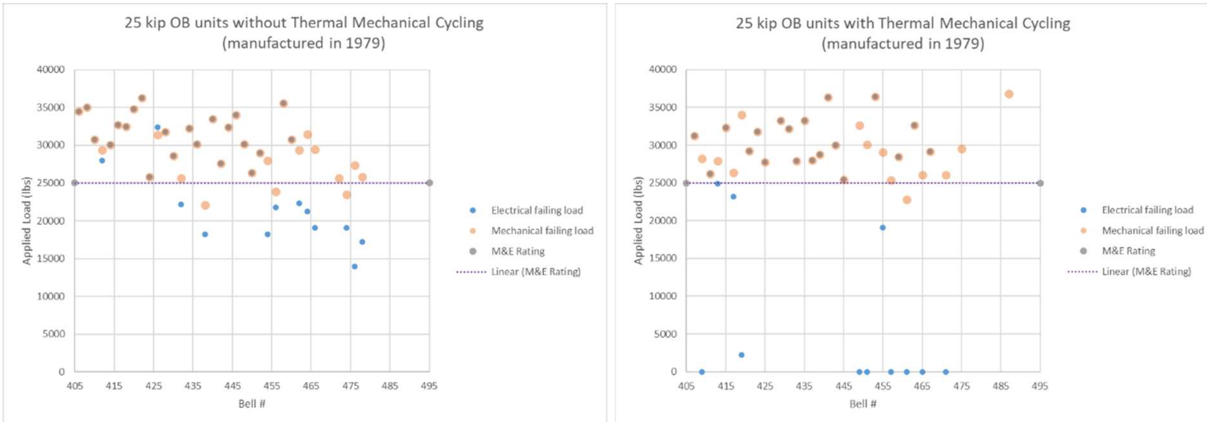


Figure 3-13
M&E test results for insulator lots 7 and 8

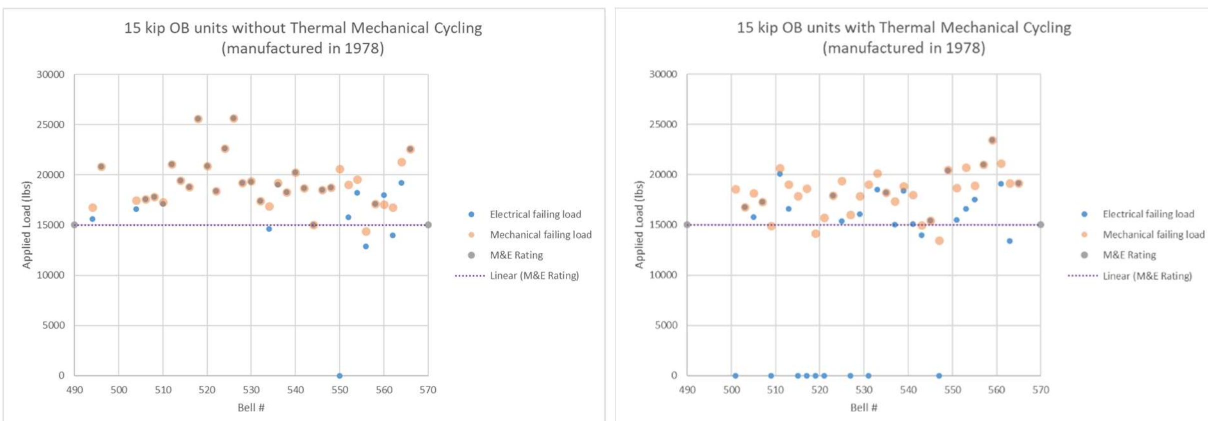


Figure 3-14
M&E test results for insulator lot 11

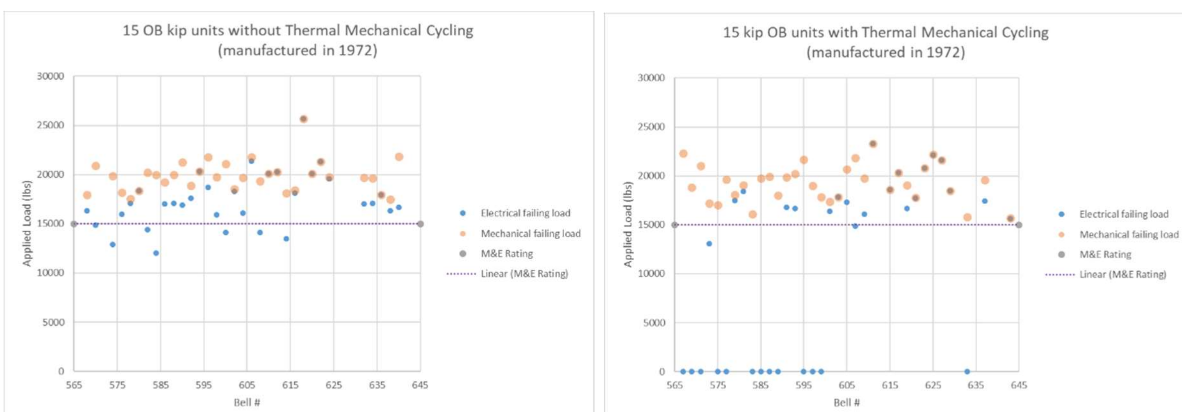


Figure 3-15
M&E test results for insulator lot 12

The left hand side of each figure gives the M&E results obtained on the insulators that had not undergone TMC conditioning (the same graphs as those shown in Figure 3-3 through Figure 3-8) while the results of the M&E tests performed on the insulators that had undergone TMC conditioning are given on the right hand sides of the figures.

Comparison of the graphs on the left hand side of each figure (representing the as-found insulators) with those on the right hand side (representing the insulators which had been subjected to TMC conditioning) reveals several obvious differences:

- the mechanical failing loads of the thermally cycled (TMC) insulators do not appear to be much lower than those of the as-found insulators
- a large number of the TMC insulators were punctured (cracked) during the thermal mechanical cycling and had virtually zero electrical strength remaining
- the proportion of insulators which punctured (cracked) during the thermal mechanical cycling appears to be greatest for the 50 kip insulators and decreases with the insulator rating.

Table 3-9 shows the results of numerical analysis of the data behind Figure 3-10 through Figure 3-15.

Table 3-9
Percentage of insulators failing to meet their assigned M&E ratings

Data Set	M&E Rating	% failing to meet M&E rating (without TMC)			% failing to meet M&E rating (with TMC)		
-	-	Electric	Mechanical	Combined	Electric	Mechanical	Combined
50 kip COB units manufactured in 1975	50000	93.2	5.1	93.2	96.6	8.6	96.6
36 kip COB units manufactured in 1977	36000	47.2	2.8	47.2	66.7	7.2	66.7
25 kip COB/CP units manufactured in 1966	25000	52.9	14.7	52.9	90.5	28.6	90.5
25 kip COB units manufactured in 1979	25000	29.7	8.1	29.7	70.8	52.3	70.8
15 kip COB units manufactured in 1978	15000	11.8	2.9	11.8	36.4	12.1	36.4
15 kip COB units manufactured in 1972/3	15000	21.2	0.0	21.2	44.1	0.0	44.1

As would be expected, the percentage of insulators failing to meet their M&E rating is larger for the insulators which were conditioned through TMC than for those not subjected to TMC.

Steep Front Testing

Steep front testing was performed on 50 kip, 25 kip, and 15 kip insulators in accordance with the test procedure detailed in Appendix B. A total of 60 of the sample insulators were tested. The tests were evenly divided between insulators that had and had not been subject to TMC. In addition to the testing of the Hydro One samples, steep front tests were performed on twenty 25 kip NGK insulators provided by EPRI. These insulators were of a similar vintage to the Hydro One insulators. The reason for testing the NGK insulators was to provide a platform for benchmarking the steep front test performance of the as-removed Hydro One 25 kip insulators. Steep front testing was not standardized until the 1980s, so the insulators tested in this work had not been subjected to steep front design tests when new. The breakdown of the steep front test samples is given in Table 3-10.

Table 3-10
Breakdown of the steep front test samples

Inventory Group	Data Set	M&E Rating	# of Units Tested	
-	-	-	Without TMC	With TMC
1	50 kip COB units manufactured in 1975	50000	5	5
2	50 kip COB units manufactured in 1975	50000	5	5
6	25 kip COB/CP units manufactured in 1966	25000	5	5
8	25 kip COB units manufactured in 1979	25000	5	5
11	15 kip COB units manufactured in 1978	15000	5	5
12	15 kip COB units manufactured in 1972/3	15000	5	5
EPRI insulators benchmarked against Hydro One units	25 kip NGK units	25000	20	-

The results of the steep front tests on the Hydro One insulators are shown in Figure 3-16 and the 25 kip NGK vs the 25-kip Hydro One benchmarking results are given in Figure 3-17. Due to the small number of samples, the results of the Hydro One insulator tests obtained for each M&E rating were grouped together. The 50 kip results reflect the aggregate results obtained with inventory groups 1 and 2, the 25 kip results combine the aggregate results obtained with inventory groups 6 and 8, and the 15 kip results combine the aggregate results obtained with inventory groups 11 and 12.

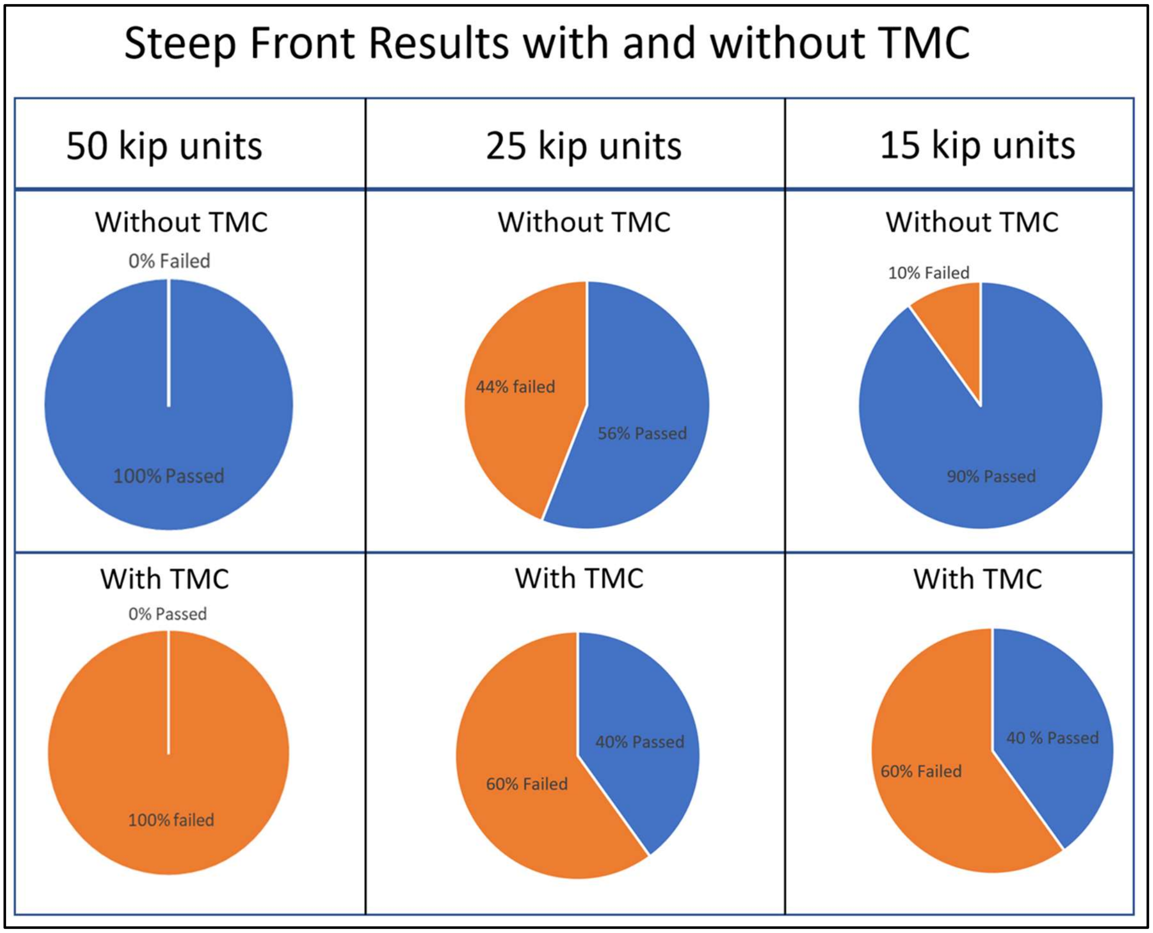


Figure 3-16
Steep front test results on Hydro One insulators with and without TMC

As can be seen from Figure 3-16, the TMC conditioning had a large influence on the percentage of Hydro One insulators passing the steep front test. The most drastic effect was observed with the 50 kip insulators which showed 100% passing without TMC and 100% failing with TMC. The 25 kip units showed 56% passing without TMC vs 40% passing with TMC, and the 90% pass rate for the 15 kip units without TMC was reduced to a 40% pass rate for insulators subjected to TMC.

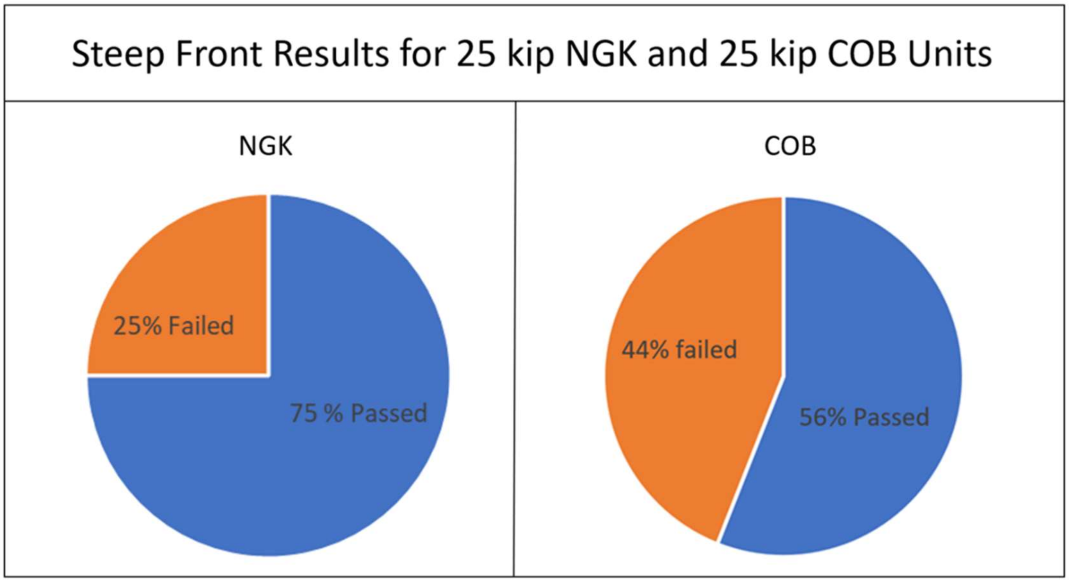


Figure 3-17
Steep front test results benchmarking Hydro One insulators against NGK units

Figure 3-17 shows that the 25-kip COB insulators (without TMC) had a steep front pass rate of 56% while the NGK benchmarking units had a pass rate of 75%. As mentioned earlier, steep front testing did not become standardized until a decade or so after these insulators were manufactured so neither design would have been exposed to this test when new. However, the 75% NGK pass rate vs the 56% COB pass rate shows that the NGK units are of a design that shows a higher resistance to steep front puncture than the Hydro One COB units.

4
COMPARISON TO STANDARDS

As mentioned at the onset of this report, M&E testing is a requirement in practically all standards prescribing the performance of insulators. The current applicable CSA standard, CSA 411.1-10: AC Suspension Insulators [7], requires that porcelain suspension insulators undergo M&E testing and that the results of the tests meet defined criteria.

CSA 411.1-10 requires that M&E tests be carried out on 10 insulators. The passing criteria for acceptance of the insulators is twofold. Firstly, the mean M&E failing load calculated for the ten insulators must equal or exceed the M&E rating plus 4 standard deviations, and secondly, each individual failing load must exceed the M&E rating. Other national standards have differing requirements but the lowest historic conformance criterion known to the authors of this report is that the mean M&E failing load calculated from the test data must exceed the rated M&E strength plus 1.2 standard deviations.

While insulators that have been in service may undergo ageing that reduces their M&E strength to below that demanded of new insulators, it is important that their M&E strength remain high enough to ensure that catastrophic insulator failures resulting in line drops do not occur. Table 4-1 shows the values of electrical, mechanical, and M&E failing loads obtained for the insulators subjected to M&E testing without TMC in light of the historic and current M&E test requirements for new insulators.

Table 4-1
Analysis of M&E data for all insulators in accordance with historic and current requirements for new insulators.

Data Set	M&E rating	M&E Statistics (w/o TMC)					
		Elect mean less 1.2 sigma	Mech mean less 1.2 sigma	M&E mean less 1.2 sigma	Elect mean less 4 sigma	Mech mean less 4 sigma	M&E mean less 4 sigma
50 kip COB units manufactured in 1975	50000	28700	52706	28700	3466	40705	3466
36 kip COB units manufactured in 1977	36000	30804	38027	30804	17389	29205	17389
25 kip COB/CP units manufactured in 1966	25000	17014	23486	17014	-551	8867	-551
25 kip COB units manufactured in 1979	25000	20336	25121	20336	843	12350	843
15 kip COB units manufactured in 1978	15000	12964	16124	12964	1033	9146	1033
15 kip COB units manufactured in 1972/3	15000	14006	17898	14006	6163	13350	6163

The data in Table 4-1 clearly demonstrate that all the groups of the as-found insulators fail to meet even the obsolete historic new insulator requirement of the mean M&E failing load being above the M&E rating plus 1.2 standard deviations. The substandard performance of the tested insulators becomes far more apparent when examined under today's requirements for new insulators which require that the mean M&E failing load exceed the M&E rating by at least 4 standard deviations. The insulator performance is so poor that the results for the group 6 insulators show that the recorded mean M&E strength less 4 standard deviations falls below 0. Such a result is clearly physically impossible and can be attributed to the combination of the extremely high 24 % standard deviation and low mean measured M&E strength.

Finally, when comparing the test data to standard requirements, it should be remembered that in addition to the requirements for the calculated mean and standard deviation, most standards require that none of the tested insulators show an M&E failing load below the specified M&E rating. Table 3-6 shows that the insulators tested (without TMC conditioning) fail to meet that requirement with the number of insulators having M&E failing loads below the specified value ranging between 93 and 12% for the six data sets.

5 APPLICATION OF THE EXPERIMENTAL FINDINGS

The state of the compromised in-service insulators can result in line drops due to two distinct mechanisms. When a string containing electrically punctured insulators undergoes a flashover due to lightning, contamination, or snow and ice bridging, there is a high likelihood that the ensuing power arc will pass through the punctured unit internally going from cap to pin [8]. This results in significant heating and pressure buildup which can cause the cap and pin to separate and the conductor to drop. The greater the number of punctured insulators in the string, the higher the probability of string flashover and string separation. Insulators which are not punctured, but have suffered a deterioration in ultimate mechanical strength do not exhibit this behavior. If a string contains mechanically compromised units, the insulators will fail if the maximum applied load exceeds the units remaining mechanical strength. The majority of conductor drops recently experienced on Hydro One's porcelain insulated transmission system fall into the former category.

In October of 2006, CIGRE WG B2.03 issued a report titled "Guide for the Assessment of Old Cap and Pin and Long-Rod Transmission Insulators Made of Porcelain or Glass: What to Check and When to Replace" [4]. The guide recommends that M&E tests be combined with Thermal Mechanical Cycling tests to assist in determining when insulator populations should be replaced. The use of TMC conditioning in our tests was based on their approach.

The CIGRE method suggests the following process:

1. Remove a sample of the suspect insulators from service.
2. Subject half of the insulators to M&E testing and calculate the mean (M1) and standard deviation ($\sigma 1$) of the measured mechanical strength.
3. Calculate the value of the mechanical load ($P1_{5\%}$) corresponding to a 5% probability of mechanical failure of the insulators based on the values of M1 and $\sigma 1$.
4. If $P1_{5\%}$ is not significantly higher than the insulators M&E rating, then subject the remaining half of the insulators to Thermal Mechanical Cycling (TMC) in accordance with IEC 60575 (see Table 3-4).
5. Perform M&E tests on the TMC insulators and calculate the mean (M2) and standard deviation ($\sigma 2$) of the measured mechanical strength and use those values to calculate the value of the mechanical load ($P2_{5\%}$) corresponding to a 5% probability of mechanical failure of the insulators based on the values of M2 and $\sigma 2$.
6. Compare the values of $P1_{5\%}$, $P2_{5\%}$ and the specified M&E rating.
7. If the value of $P2_{5\%}$ is lower than both $P1_{5\%}$ and the specified M&E strength, then the insulators should be expected to continue deteriorating and it is recommended that they be "re-tested and/or closely monitored and/or replaced". replaced have reached the end of their useful life and should be. In the case where both $P2_{5\%}$ is below $P1_{5\%}$ and both values are

lower than the specified M&E rating the insulators have reached the end of useful life and must be replaced.

The analysis concept described above is shown diagrammatically in Figure 5-1.

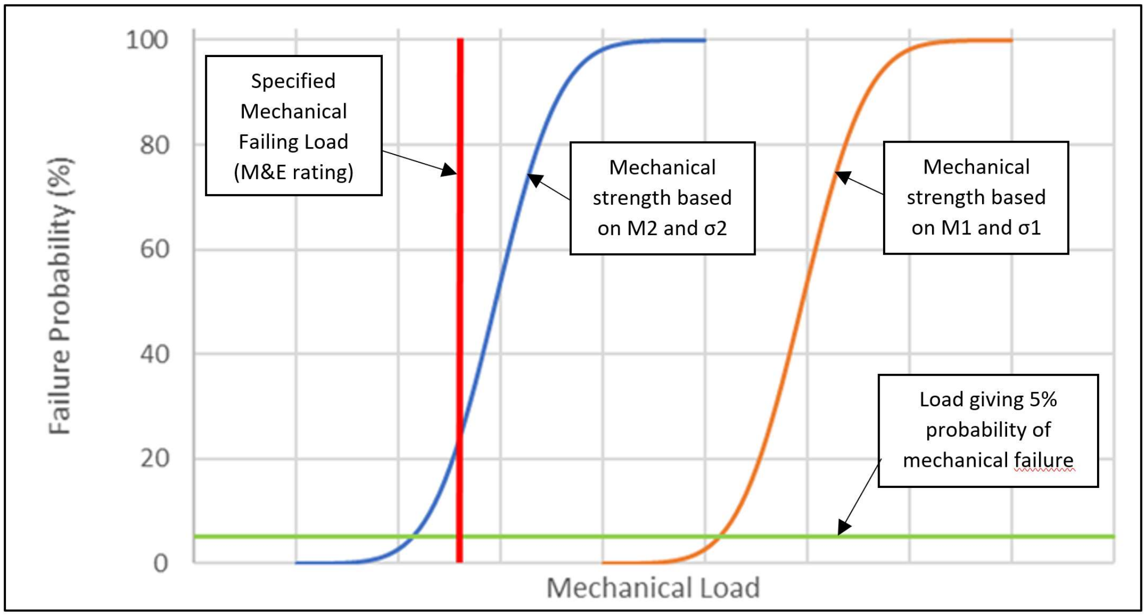


Figure 5-1
M&E and TMC analysis recommended by CIGRE

Our tests followed the above procedure with the exception that the TMC performed comprised only 2 cycles rather than the IEC recommended 4 cycles. As explained earlier, the number of cycles used in the TMC was reduced due to concern that the recommended 4 cycles would break too many of the insulators.

The IEC standard TMC procedure and the procedure that was followed in these tests are described in detail in Appendix B.

The analysis of the test results is given in Table 5-1.

Table 5-1
Results of the test analyzed in accordance with CIGRE recommendations

Inventory Group	Data Set	M&E Rating	Mechanical load corresponding to 5% failure probability without TMC ($P1_{5\%}$)	Mechanical load corresponding to 5% failure probability with TMC ($P2_{5\%}$)
		(lbs)	(lbs)	(lbs)
1 and 2	50 kip COB units manufactured in 1975	50000	49278	47305
3 and 4	36 kip COB units manufactured in 1977	36000	35506	32762
6	25 kip COB/CP units manufactured in 1966	25000	19309	17871
7 and 8	25 kip COB units manufactured in 1979	25000	21472	22896
11	15 kip COB units manufactured in 1978	15000	14131	13827
12	15 kip COB units manufactured in 1972/3	15000	16599	15464

As can be seen from the tabulated results, the mechanical load corresponding a 5% failure probability for the TMC insulators ($P2_{5\%}$) and is lower than both the mechanical load corresponding a 5% failure probability for the non TMC insulators ($P1_{5\%}$) and the specified mechanical strength (M&E rating) for all but the group 12 insulators. In addition, the data show that for the group 1, 2, 3, 4, 6, 7, 8, and 11 insulators, the mechanical load corresponding to a 5% failure probability for the non TMC insulators ($P1_{5\%}$) is below the specified M&E strength. Based on these results, it is clear that the insulators have reached the end of useful life and should be replaced. The only group of insulators not clearly requiring replacement is group 12. However, given that their performance is only marginally better than that where immediate replacement is recommended, the prudent course of action is to replace all of the insulators.

As mentioned earlier in this section, the CIGRE guidelines do not take insulator puncture into consideration. Given the fact that most of the recent line drops experienced by Hydro One have been caused by punctured insulator separation due to flashover and power follow current, further credence is given to the recommendation to replace the insulators because of:

- the propensity for the insulators to puncture (crack) during TMC
- the fact that the insulators are highly susceptible to electrical puncture under steep transient voltages due to lightning
- the finding that TMC drastically decreases the already weak ability of the insulators to withstand electrical puncture
- the fact that a significant number of insulators separated mechanically during the TMC.

6
RECOMMENDATIONS

The analysis of testing performed on the 591 insulators removed from service in 2017 provides overwhelming evidence supporting replacement to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation of this work is that the identified population of COB and CP insulators be removed from service as soon as practically possible.

7 REFERENCES

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[2] E. Cherney, A. Baker, B. Freimark, R. Gorur, Z. Lodi, M. Marzinotto, I. Ramirez-Vasquez and G. Stewart, "Evaluation of and Replacement Strategies for Aged High-Voltage Toughened Glass-Suspension Insulators," *IEEE Transactions on Power Delivery,* vol. 30, no. 3, pp. 1145-1152, 3 June 2015.

[3] "Results and Analysis of Phase 1 Insulator Tests Performed in Support of HydroOne Insulator Replacement Program," EPRI, Charlotte, 2016.108294.

[4] CIGRE WG B2.03, "Guide for the Assessment of Old Cap and Pin and Long Rod Transmission Insulators Made of Porcelain or Glass: What to Check and When to Replace," 2006.

[5] ANSI, "American National Standard for Insulators - Wet Process Porcelain and Toughened Glass - Transmission Suspension Type," National Electrical Manufacturers Association, Rosslyn, VA, 2013.C29.2B.

[6] IEC, "Thermal-mechanical performance test and mechancial performance test on string insulator units," International Electrotechnical Commission, Geneva, 1977.CEI/IEC 575:1977.

[7] CSA Group, "AC suspension insulators," Canadian Standards Association, Mississauga, 2010.C411.1-10.

[8] "Ceramic Insulator Assessment: Approach to Assessing a Population of Porcelain Disc," EPRI, Palo Alto, CA, 2007.1015277.

A
CHECK OF DEFECTIVE INSULATOR MANUFACTURING START DATE

Phase 1 of the testing identified potentially deficient performance in a sample of COB 1963 insulators, this raised the question as to whether 1965 is the correct cut-off year for defective insulator production. In order to explore this question, the as-found tests were performed on a 20 15 kip CP and COB insulators from 1952 and 20 15-kip COB insulators from 1963.

The Megger and ac withstand tests showed that there were no punctured insulators in either of the samples. The results of the M&E test are presented below in Figure A-1.

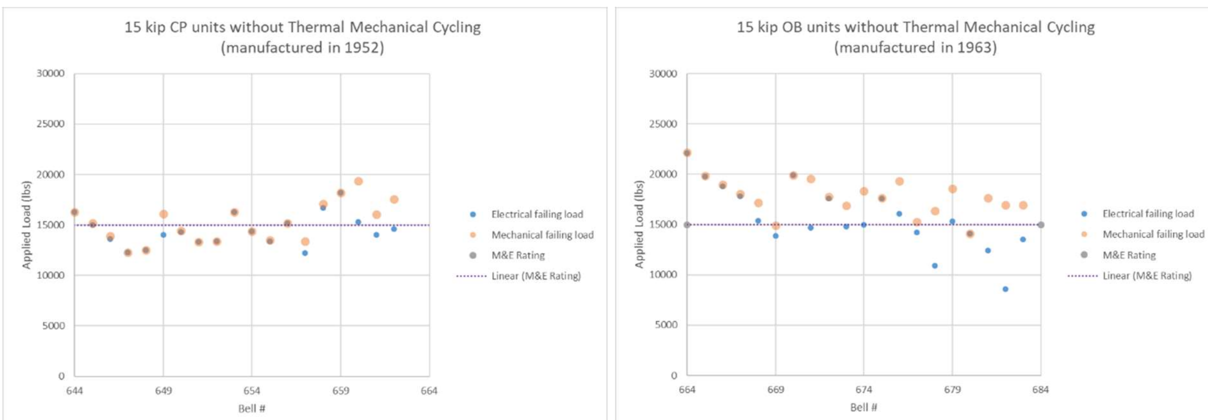

Figure A-1
Results of M&E tests on 1952 CP/COB and 1963 COB insulators

The data in Figure A-1 were analyzed as normal distributions to obtain the mean and standard deviations of the electrical strength, the mechanical strength and the M&E strength. The calculated mean and standard deviation for the two groups of insulators are shown in Table A-1.

Table A-1
M&E performance of 1952 CP/COB and 1963 COB insulators

Insulator Group	# of bells	# of bells meeting rating			M&E Statistics					
		Electric	Mech	Both	E mean (lbs)	E sigma %	M mean (lbs)	M sigma %	Comb mean (lbs)	Comb sigma %
15 kip CP units 1952	19	7	10	7	14469	11.0	15183	13.1	14469	11.0
15 kip OB units 1963	20	10	18	10	15625	20.6	17826	10.7	15625	20.6

The results shown in Table A-1 were not significantly different from those generated in the testing of the 15 kip insulators manufactured in 1978 and 1972/3. As such, the results of the tests on the 15 kip insulators manufactured in 1952 and 1963 were not sufficiently conclusive to verify the currently accepted cutoff year of 1965.

B DETAILED DESCRIPTION OF THE TEST PROTOCOLS

Megger Test

The insulator is tested using a 10 kV megger. The intent of the test is to determine the insulators resistance under a 10 kV dc voltage. The megger is connected between the cap and pin of the insulator, and insulators are tested individually with the measured resistance being recorded for each unit.

Figure B-1 shows the Megger test instrument and Figure B-2 shows insulators undergoing Megger testing.

Figure B-1
Example of a 10 kV Megger

Figure B-2
Insulators undergoing Megger test

AC Withstand Test

The ac withstand test is intended to assess the electrical condition of the insulators. The procedure comprises energizing several insulators at a time with a 60 Hz supply. The voltage is raised to approximately 70% of the insulators' power frequency flashover voltage and maintained for a period of 1 minute. If there is a breakdown in any of the units under test, the unit will be identified and assigned an internal flashover value.

Figure B-3 shows insulators undergoing the ac withstand test.

Figure B-3
Insulators undergoing ac withstand test

M&E TEST

The M&E test is performed on each of the insulators. The insulator is mounted in a tensile testing machine. The test comprises applying 60% of the insulator flashover voltage to the unit under test and gradually increasing the tensile load until failure occurs. Failure is defined as the load at which the insulator ceases to support either the mechanical load or the applied voltage. If the insulator ceases to withstand the applied voltage before mechanical failure, the load at electrical failure is recorded and the loading is increased until mechanical failure occurs. The failure mode can vary between insulators. Typical mechanical failure modes of aged insulators include pin breakage, cap breakage, pin slip-out, porcelain breakage, etc. and is recorded for each insulator. Figure B-4 shows the test setup and Figure B-5 shows several examples of different modes of failure.

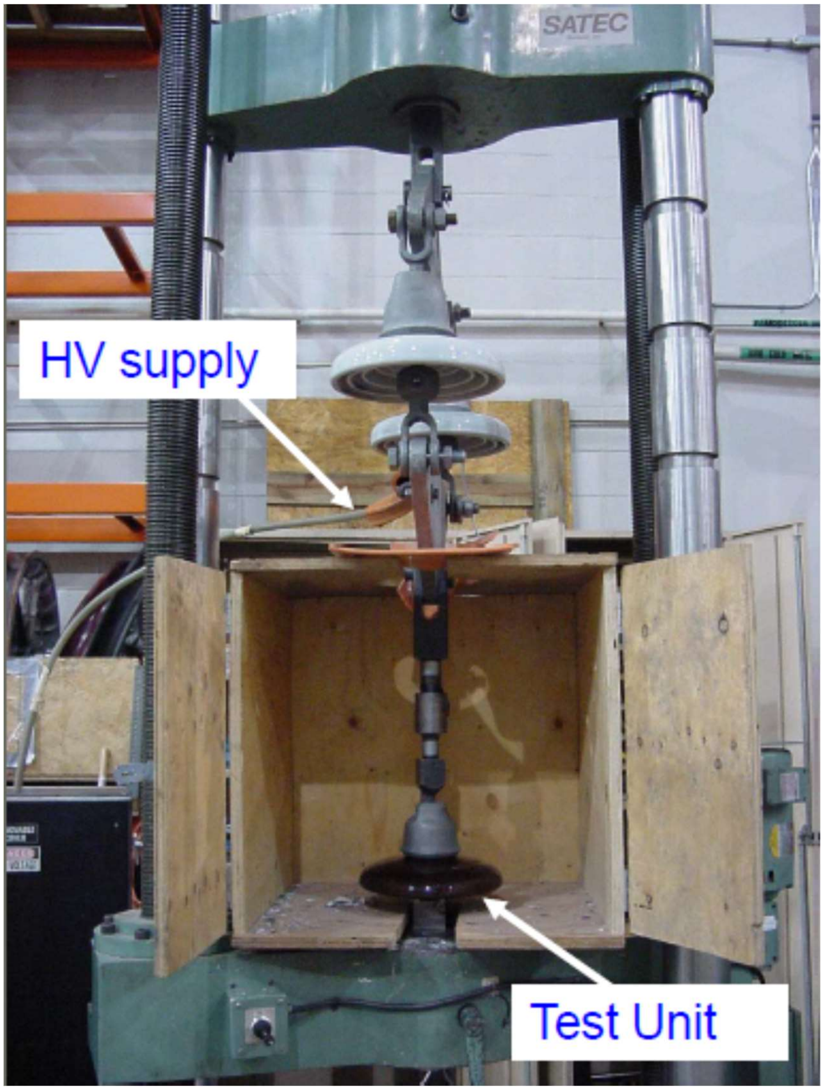

Figure B-4
M&E Test setup

B-4

Figure B-5
Typical modes of failure observed with the aged population of insulators being investigated

Thermo-Mechanical Test

The Thermal-Mechanical Load Cycle Test is designed to simulate the aggregation of everyday conditions that an insulator installed in Canada might experience during its lifetime in service. The test includes a superposition of at least three contributions to the mechanical stressing of the porcelain: the part due to the applied tension, the part due to the cement expansion, and the thermal strains.

During the Thermal-Mechanical Cycling Test described in IEC 60575, the insulators are subjected to four 24-hour cycles of ambient air cooling and heating with a simultaneously applied tensile load. Each 24-hour cycle starts with a cooling period followed by a heating period. The procedure requires that in the cooling period, a low temperature of -50 ℃ is maintained for at least a four-hour period while during the heating period a high temperature of 50 ℃ is maintained for a period of at least the same duration. During the two extreme temperature periods in each cycle, the tensile load applied to the insulators is maintained at 65% of the M&E rating of the insulators. Figure B-6 illustrates the test procedure.

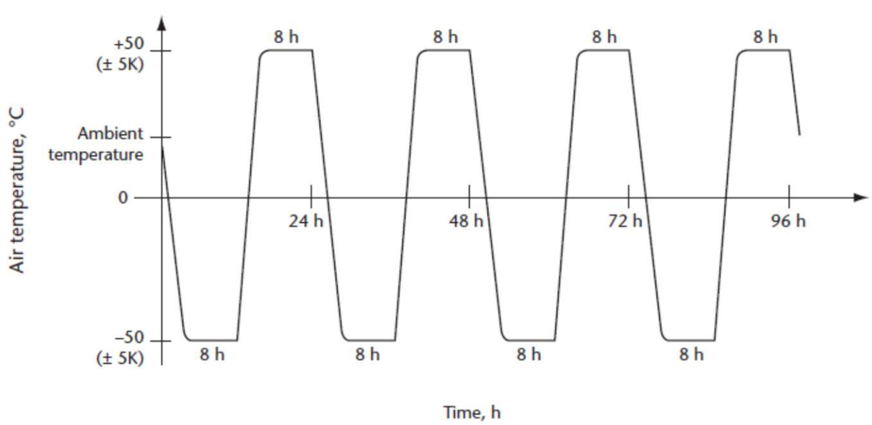

Figure B-6
Thermal-Mechanical Cycling Test Procedure

The tensile load is completely removed and reapplied at the end of each of the first three 24-hour thermal cycles. During testing, the ambient air temperature of the chamber is maintained, as required by the standard, at within 5℃ of the specified extreme temperatures in the two extreme temperature periods. At the end of the fourth thermal cycle, upon cooling the chamber to room temperature, the tensile load is removed.

The large temperature variation chosen for the test was to maximize the thermal stresses caused by the differential expansion of the steel pin, the cement and the porcelain. It is known that moisture ingress into the insulator cement is largely responsible for cement expansion.

Figure B-7 shows a set of insulators installed in the Thermal Mechanical chamber ready for testing.

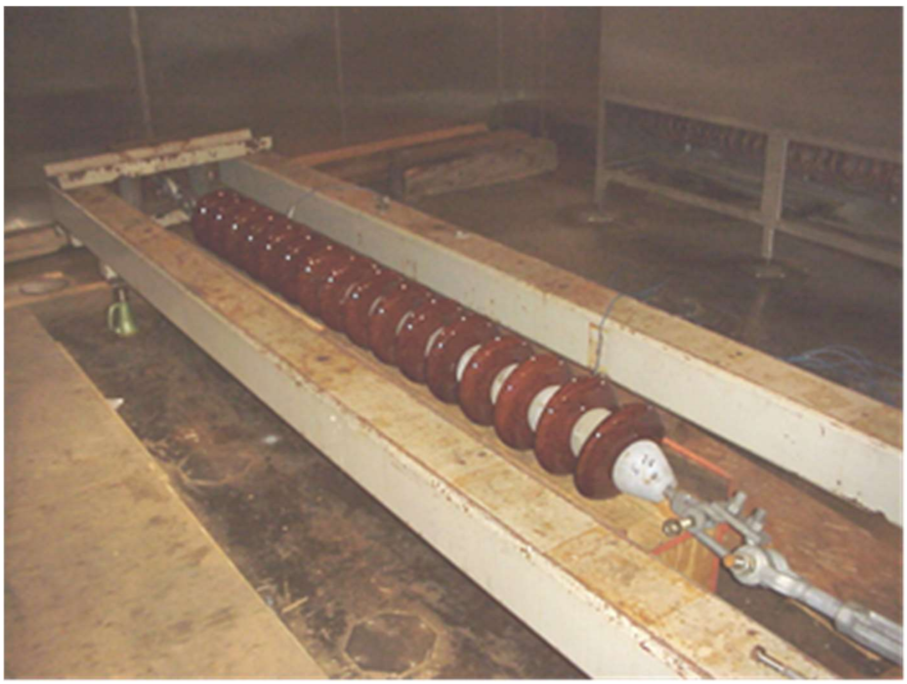

Figure B-7
Insulators installed in Thermal Mechanical test setup

Since the insulators that are to be aged through Thermal Mechanical testing have been significantly aged in-service and are known to be defective, there was concern that using the standard IEC test parameters (temperature, loading, number of cycles) as recommended for new insulators may result in mechanical failure of many of the insulators during the Thermal Mechanical test. Based upon the results of the phase 1 testing, it was elected to perform the test using the temperature, loading, and cycle duration recommended in the IEC standard (which is less severe than the CSA standard), but with the number of cycles reduced from 4 to 2.

Steep Front Puncture Test

The steep front puncture test is designed to simulate the voltage impressed on insulators as a consequence of lightning strikes. In-service line insulators are subjected to steep front overvoltages due to lightning. The rise times of these overvoltages vary from several hundred to several thousand kilovolts per microsecond. For the faster voltage surge rise times, i.e., 2,500 kV/µs, the formative time lag for external flashover of the insulator allows for a very high voltage to be reached before external flashover occurs. Although this voltage appears across the full insulator string, the non-linear voltage distribution along the string results in the development of a very high voltage stress across the first few line-end units. Repeated exposure to such high lightning generated stresses can lead to partial breakdown of the porcelain/glass dielectric, and eventual complete puncture of the dielectric within the head of the insulator.

In order to test an insulator's ability to withstand exposure to the very high lightning generated voltages which can occur in service, it is necessary to apply a very high voltage between the cap and the pin. If this is attempted in air using either power frequency or standard lightning impulse voltages, the air around the insulator always breaks down at a voltage much lower than the highest voltages seen in the field.

In the 1970's the industry expressed interest in developing a puncture test that was more representative of in-service conditions under which punctures occur. This prompted the investigation into and the development of the steep front impulse voltage puncture test. The following paragraphs explain the approach used in the development of the steep front impulse puncture test.

When a standard 1.2 x 50 us lightning impulse voltage of sufficiently high peak magnitude is applied to an insulator, a flashover through the air around the insulator will always occur. If the peak magnitude of the applied impulse is increased while the waveshape is maintained the same, the steepness of the applied voltage increases.

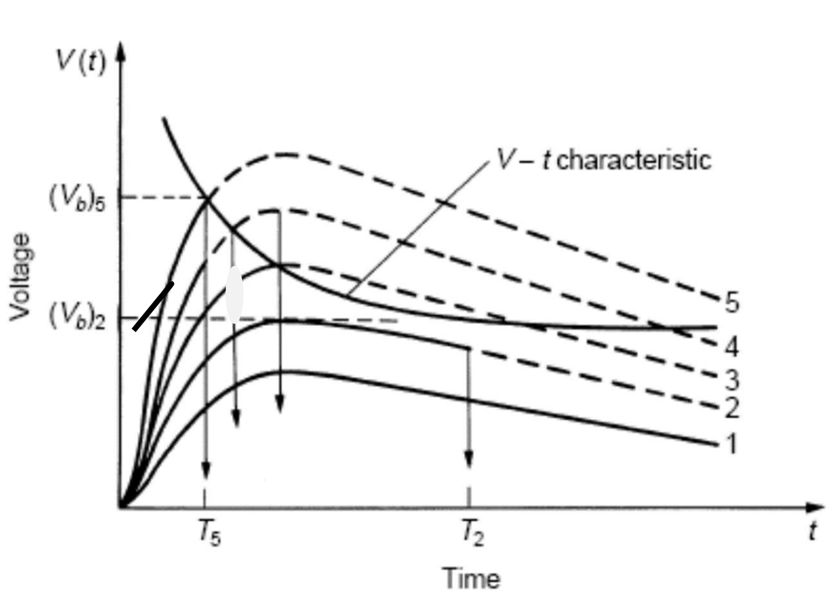

Figure B-8
Volt-time curve

Figure B-8 shows a set of 5 standard lightning impulses of constant shape but increasing peak value. Curve 1 has a peak value below the minimum breakdown voltage (Vb2) and therefore does not cause a breakdown. Curve 2 has a peak value approximately equal to the minimum breakdown voltage and therefore breakdown occurs, but takes place on the tail of the applied impulse. As the impulse magnitude is gradually increased (curves 3 through 5), the breakdown of the air occurs at progressively shorter times on the front of the impulse and at progressively higher voltages. The solid curve labeled “V-t characteristic” is the line obtained by drawing a curve through the points at which breakdown occurs under standard lightning impulses of increasing magnitude. As can be seen from the V-t curve, the voltage at which an air gap breaks down increases as the steepness of the applied voltage is increased. This phenomenon is due to the time lags associated with the development of discharges and is fully explained in the literature. This increase in the breakdown voltage of air with increasing steepness of the applied impulse is the fundamental principle upon which steep front impulse testing is based.

The primary advantage of the steep front impulse puncture test is that the voltage impressed across the solid dielectric within the insulator head is similar both in shape and magnitude to that encountered in service under lightning induced overvoltages. Figure B-9 shows the steep front test setup used for the puncture tests.

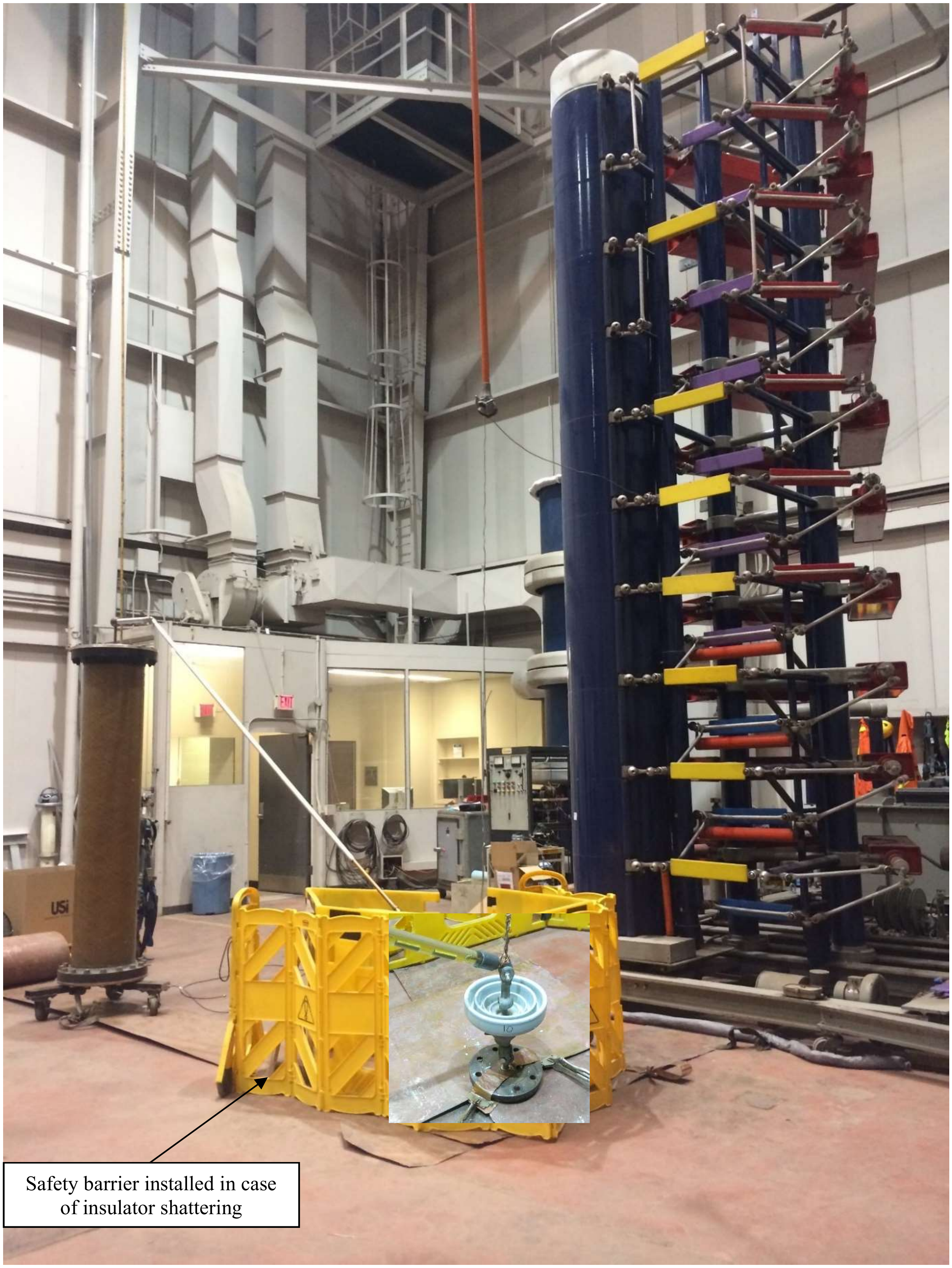

Figure B-9
Steep front test setup

The steep front puncture testing was carried out in accordance with IEC Standard 61211. Five insulators from each group were tested using a 20 impulse test sequence of

- Five positive impulses
- Five negative impulses
- Five positive impulses
- Five negative impulses

The impulse had a peak voltage of 2.8 times the CFO of the insulator. The insulator passes the test if no punctures occur.

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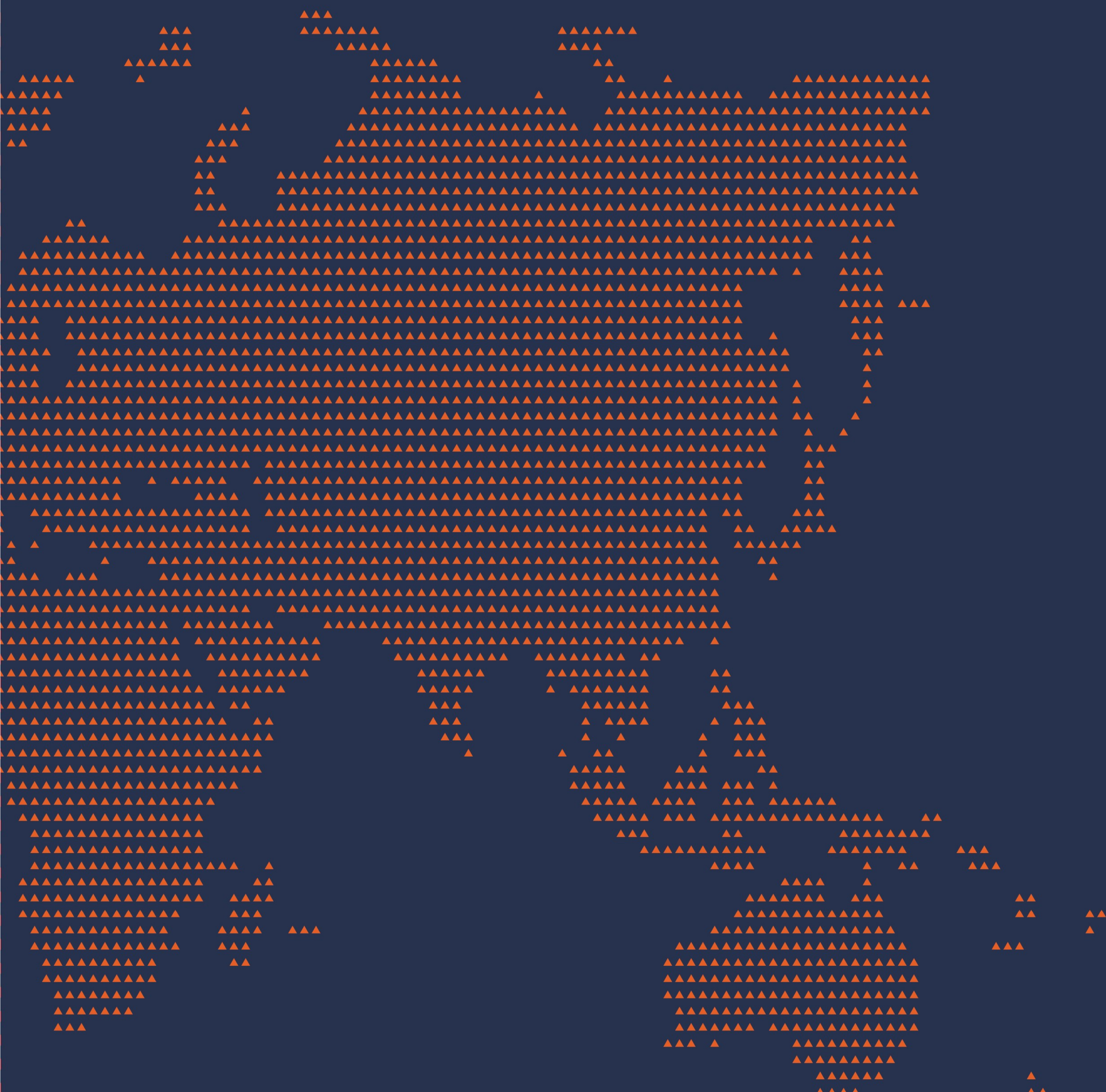

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Review of HONI's Capabilities in Transmission Asset Analytics and Reliability Risk Modelling

Final Report & Conclusions

May 8th, 2018

Prepared For:

Hydro One Networks Inc.

Prepared By:

METSCO Energy Solutions
2550 Matheson Blvd East
Mississauga, ON, L4W 4Z1

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Review of HONI's Capabilities in Transmission Asset Analytics and Reliability Risk Modelling

Final Draft Report

METSCO Report # 18-135

May 8th, 2018

Experts:

Alexander Bakulev
Vice President

Robert Otal, B.Eng., P.Eng
Director, Asset Management & Analytics

Dmitry Balashov, MBA, MPA
Director, Utility Strategy and Economic Regulation

Approved By:

Thor Hjartarson, M. Sc., P. Eng.
Chief Executive Officer

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Version	Date	Description
Version 1	April 17, 2018	Final draft report
Version 2	May 8, 2018	Final report

Executive Summary

Hydro One Networks Inc. ("HONI" or "Hydro One") retained METSCO Energy Solutions Inc. ("METSCO") to perform a third-party assessment of three elements of its transmission system asset planning process, namely the Asset Analytics (AA), Asset Risk Assessment (ARA) and Reliability Risk Model (RRM) frameworks. Each of the three capabilities plays a distinct role in the utility's transmission planning work, and along with other analytical, diagnostic and stakeholdering inputs, collectively manifest themselves in the form of Transmission System Plans (TSP) submitted to the Ontario Energy Board (OEB).

METSCO's involvement in this project entailed gathering of information and conducting document and data analysis – either through on-site interviews with HONI subject matter experts, or by way of independent review of information supplied by the utility. To structure our assessment and present our findings in both a comprehensive and a transparent manner, METSCO devised two discrete evaluation frameworks used for the AA/ARA, and the RRM frameworks respectively. We opted to rely on two separate evaluation frameworks in light of the relative degree of significance between the AA/ARA and RRM capabilities within HONI's capital planning process, and certain distinct technical attributes that warrant more focused attention.

In the case of the AA and ARA capabilities, which form the backbone of HONI's transmission system Asset Management (AM), we utilized a comprehensive three-level evaluation framework, assessing the Overall Process Integrity, Asset Class-specific Assessment Parameters, and Practical Outcomes of the Analysis. Our criteria and conclusions within each level of assessment reflect our extensive experience and expertise in the area of electricity system asset management, system planning and advanced analytics. In employing a three-level review structure, METSCO was able to consider multiple key dimensions of the AA and ARA capabilities, namely:

- Their overall robustness, completeness and sophistication;
- The suitability of technical parameters used in asset class-specific analysis;
- Whether the outputs can be expected to contribute to prudent planning.

The detailed evaluation parameters comprising each framework are outlined in the sections that follow.

Our evaluation of the RRM capability – a forecasting tool the output of which is used in customer engagement efforts to outline directional changes to reliability risk relative to expenditure levels, to demonstrate the value of proposed investments and help HONI elicit the input from customers – proceeded by way of a framework that evaluates the robustness, completeness and sophistication of system reliability forecasting.

METSCO developed this framework based on our experience of working in the issue area of reliability forecasting with utilities across North America, including development and implementation of reliability forecasting models, reliability forecasting best practices research, and third-party assessments of reliability predictive capabilities deployed by individual utilities.

In relation to the evaluation framework for the AA / ARA capabilities, the RRM evaluation framework is comparable to the top-level Overall Capability Sophistication framework, albeit using slightly modified criteria. Unlike the AA / ARA capabilities, however, METSCO did not conduct a deeper level of analysis for the RRM framework, such as the asset-class specific technical issues, or the manner in which the model's outputs inform further planning decisions. The reason for this comparatively lower granularity of review of the RRM relative to AA/ARA capabilities is the more limited degree of application of RRM results within the asset management processes. Since RRM is to show utilized within the customer engagement stage of asset planning work – an area out of scope of this report – METSCO is not in a position to opine about the merits of its practical application.

The following diagram provides a comprehensive overview of the evaluation frameworks presented in this report:

Assessment Level and Description	Asset Analytics (AA) & Asset Risk Assessment (ARA) Capabilities	Reliability Risk Model (RRM) Capability
	Criteria / Areas of Review	Criteria / Areas of Review
Level 1: **Overall Capability Sophistication** *How do HONI's capabilities rank in terms of their overall robustness, comprehensiveness and sophistication relative to common industry practices?*	Use of Risk-Based Analysis Data Utilization and Management Assessment Flexibility Ease of Comprehension Clear Sense of Gaps & Improvement Plans	Integration into the AM Process Approach Definition Forecasting Complexity Data Input Management Clear Sense of Gaps & Improvement Plans
Level 2: **Technical Parameter Robustness** *Do analytical approaches to the individual asset classes reflect the rigour expected of a utility of HONI's size and sophistication?*	Power Transformers Circuit Breakers Transmission Conductors Protection, Control & Telecom Station Ancillary Assets Underground Cables	No Further Assessments
Level 3: **Practical Application Issues** *How does HONI use the insights produced by these capabilities in practice?*	AA/ARA Application Case Studies: Projects supported by both AA & ARA Projects supported by AA but not ARA Projects Supported by ARA but not AA	No Further Assessments

METSCO Assessment Framework

Given their current methodological makeup and manner of utilization, we conclude that on balance across the categories of our assessment, the AA and ARA capabilities are comparable to advanced asset management practices found elsewhere in the industry.

Both AA and ARA capabilities are sufficiently rigorous and robust to accomplish their intended tasks, integrating within them all elements of advanced asset management capabilities, such as asset condition assessment, failure curves, and alternatives analysis, among many others. While we make a number of recommendations for further enhancements of the AA/ARA systems across the specific asset classes examined, we note that the status quo of asset-class specific evaluation parameters is predominantly in line with advanced industry practices, with certain analytical elements approaching best-in-class capabilities.

In assessing the practical application of outputs of both AA and ARA capabilities, METSCO observed case study examples supporting the complementary nature of both frameworks, including instances where the outputs of the AA framework were modified by the insights from the ARA analysis that incorporates a comparatively greater degree and variety of quantitative and qualitative information, and vice versa. In both cases, the complementary insights generated through the use of the two capabilities suggested the courses of action that were more beneficial for the utility and its ratepayers than the use of any one framework in isolation. While this is a positive finding in the context of HONI's asset management practices, it also highlights the potential pitfalls of overwhelmingly relying on automatically generated quantitative outputs alone, as we discuss in the section detailing our review of practical case studies.

With respect to the Reliability Risk Model, METSCO's finding is that the tool's analytical underpinnings and functionalities trail advanced industry system reliability practices where these are deployed in the asset management. In making this observation, we note that a number of utilities do not or have not until recently attempted to formally forecast system reliability in a comprehensive manner. This contextual observation suggests that the RRM capability constitutes a bona fide continuous improvement step. Given that the RRM tool is currently used primarily as a customer communications tool to convey indicative changes to reliability risk levels across spend scenarios, the observed gaps in its technical parameters pose no meaningful risks from the asset planning perspective. We observe that the RRM tool's outputs could add a valuable "technical implications" dimension to customer engagement efforts, so long as HONI is clear about the tool's purpose and the implications of its analysis.

Notwithstanding these findings, potential improvements to the RRM capability (or another reliability forecasting capability that HONI may choose to procure) that METSCO recommends in this report, would enhance its practical applicability and robustness, should HONI decide to integrate the tool as part of the asset management decision-making process more broadly.

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I Introduction

1.1. Purpose of the Study

METSCO Energy Solutions Inc. was contracted by Hydro One Networks Inc. to perform a third-party assessment of three elements of Hydro One's transmission asset management and capital planning process, namely the Asset Analytics, Asset Risk Assessment and Reliability Risk Model capabilities.

The overarching objective of our review was to establish whether the capabilities in question are sufficiently robust and rigorous to generate objective and valuable inputs into Hydro One's transmission system asset planning, given each tool's intended purpose. The scope of the study included a review of the AA/ARA processes in the broader context of the asset management decision-making process, a review of the AA methodology and the underlying scoring criteria, along with the data inputs and areas for improvement for the following asset classes: Substation Power Transformers, Circuit Breakers, Protection Control and Telecom, Station Ancillary, Transmission Conductors and Underground Cables.

The analysis of the RRM included a review and assessment of HONI's reliability risk projection approach and underlying mathematical algorithms, and identification areas of improvement with further recommendations. Our analysis and findings are grounded in extensive subject matter interviews, independent review of the documents, data and other materials provided by Hydro One.

Of the three capabilities that METSCO reviewed, the ARA and AA elements play a significantly more prominent role in HONI's asset planning processes compared to their RRM counterpart, which to date has been used exclusively as a directional risk communication indicator across multiple expenditure scenarios, with its outputs used in customer engagement efforts. Accordingly, we dedicated the bulk of our assessment efforts to the AA and ARA capabilities, given their comparatively greater scope, nature, and impact on Hydro One's planning and budgeting decisions.

1.2. Report Structure

The introductory chapter of this report describes the purpose of the study and the report structure, with the remainder outlining the details of the framework METSCO developed to conduct the review. Chapter 2 describes the key functional characteristics and nature of all three capabilities (AA, ARA and RRM) under review. Chapter 3 contains the details of assessment work performed in relation to the Asset Analytics and Asset

Risk Assessment methodologies, including several mini-case studies that describe the manner in which these frameworks' outputs affect the utility's actual asset management decisions. Chapter 4 contains the details of assessment of the Reliability Risk Model. The final Chapter of this report contains our conclusions and recommendations with respect to potential methodological and practical enhancements related to all three examined capabilities.

1.3. METSCO's Evaluation Frameworks Applied in the Report

Each of the three capabilities METSCO examined in the context of our engagement, represents a custom solution, emanating from Hydro One's legacy technical capabilities and data availability, emerging strategic and operational needs, its response to the incremental regulatory environment changes, and other utility-specific considerations. Notwithstanding the degree of incremental customization and continuous development (altogether common in the utilities industry), in METSCO's experience, most Asset Management analytics capabilities share a fundamental set of attributes that drive their overall effectiveness, efficiency and integrity.

At the core of any capability's value proposition are the logic, rigour, and comprehensiveness of its core analytical methodology, or the manner in which the capability selects and transforms the inputs of analysis into its ultimate outputs. Equally important, however, are the operational and organizational aspects of a given AM capability, including the form and function of its integration with other utility systems and processes; the clarity / ease of its comprehension by the utility's employees; and the manner in which it approaches unique aspects of individual asset classes or system components. Finally, an AM capability's value is ultimately reflected in the degree to which its outputs enable the utility to accomplish its intended objectives in practice.

The assessment framework that METSCO devised for the purposes of this engagement reflects all of these overarching considerations across its three levels or "layers" of assessment:

- At the highest level, entitled the *Overall Capability Sophistication*, we conduct a "system-level" review of the capabilities' key methodological and operational features, in an attempt to establish whether they are appropriate for a utility of HONI's size and sophistication. This is the only level of assessment we apply to all three capabilities.

- The second level of our assessment, which we call *Technical Parameter Robustness*, reviews in greater detail the technical elements of assessments applicable to the major asset classes. This assessment stage examines whether the tools utilize the appropriate data and analytical techniques for the major asset categories they review.

- The third and final level of our assessment – the *Practical Application Issues* – entails a review of case studies illustrating the manner in which the analytical insights generated by the capabilities under review help Hydro One make asset management decisions that maximize the value of their capital expenditures.

Figure 1 provides a visual overview of the assessment framework we applied in the course of this study:

Assessment Level and Description	Asset Analytics (AA) & Asset Risk Assessment (ARA) Capabilities	Reliability Risk Model (RRM) Capability
	Criteria / Areas of Review	**Criteria / Areas of Review**
Level 1: **Overall Capability Sophistication** *How do HONI's capabilities rank in terms of their overall robustness, comprehensiveness and sophistication relative to common industry practices?*	Use of Risk-Based Analysis Data Utilization and Management Assessment Flexibility Ease of Comprehension Clear Sense of Gaps & Improvement Plans	Integration into the AM Process Approach Definition Forecasting Complexity Data Input Management Clear Sense of Gaps & Improvement Plans
Level 2: **Technical Parameter Robustness** *Do analytical approaches to the individual asset classes reflect the rigour expected of a utility of HONI's size and sophistication?*	Power Transformers Circuit Breakers Transmission Conductors Protection, Control & Telecom Station Ancillary Assets Underground Cables	No Further Assessments
Level 3: **Practical Application Issues** *How does HONI use the insights produced by these capabilities in practice?*	AA/ARA Application Case Studies: Projects supported by both AA & ARA Projects supported by AA but not ARA Projects Supported by ARA but not AA	No Further Assessments

Figure 1. METSCO Assessment Framework

Our assessment of the Reliability Risk Model does not extend beyond this first level of assessment. The rationale for this decision is primarily grounded in the limited extent to which it is integrated Hydro One's asset management processes, (notwithstanding its use in customer engagement work as a risk communications and feedback generating tool)

Moreover, given the technical complexity of the AA and ARA capabilities and their relative significance in the utility's asset management work, our decision not to proceed with Levels 2 and 3 analysis for the RRM tool is also a practical matter of prioritizing among the project's multiple objectives on the basis of their significance, in an effort to concentrate the majority of our investigative efforts in the areas expected to be most relevant to this report's ultimate audience. For clarity, it is

METSCO's professional opinion that the assessment of the RRM framework that we do undertake in this report is sufficiently rigorous to render an informed opinion on the tool's effectiveness in the context of asset management today, and provide Hydro One with practical recommendations for further potential improvements to the model, or parameters of alternative reliability forecasting solutions it may wish to explore.

METSCO's selection of specific criteria underlying each level of this assessment, along with our expectations as to what constitutes an "appropriate" level of complexity and sophistication, is informed by our extensive experience in the field of utility asset management in most Canadian provinces and territories, and multiple jurisdictions in the United States and Europe.

In the course of these past engagements, METSCO developed theoretical methodologies and practical tools for optimization of capital asset lifecycles, independently reviewed the capabilities and asset management plans of multiple utilities, conducted inter-jurisdictional best practices reviews of asset management and reliability forecasting best practices, and contributed to academic literature on the related topics. While our assessment of Hydro One's capabilities does not amount to a direct peer-to-peer comparison across specific utilities, our mode of enquiry and the subsequent conclusions reflect a diversity of these experiences, along with the expertise we acquired and refined in process.

Prior to discussing the nature of each assessment step in more detail, we note that our review did not consider the additional "upstream" procedures associated with the inputs used within AA, such as mechanics of algorithms used to calculate the condition results, nor did this evaluation consider the additional "downstream" procedures such as the hand-offs between the planning group and the execution group, where planned work is formally scheduled, resourced and executed within the system.

1.3.1. *Assessment Level One: Overall Capability Sophistication*

The first level of METSCO's assessment, applied to all of AA, ARA and RRM capabilities, entails a system-level review across the key technical, operating, and methodological dimensions that enable these tools and processes to achieve their desired objectives. The goal at this stage of analysis is to establish whether a capability exhibits the combination and quality of key features that can be reasonably expected of a similar tool for a utility of Hydro One's size and complexity. We refer to this level of assessment as the Overall Capability Sophistication review.

A complicating feature of our review at this level arises from the fact that the three capabilities subjected to our analysis are substantially different from a functional perspective. While the RRM capability amounts to a discrete tool used for a single purpose, the ARA functionality represents an overarching process that integrates multiple tools, activity systems, and types of analytical, diagnostic and consultative data. Finally, the AA capability is positioned between the two extremes in terms of complexity of its outputs and the processes that generate them.

To account for this functional variety, METSCO opted to use two separate sets of criteria – one for AA and ARA capabilities, and another for the RRM. In doing so, we were able to highlight certain issues that are specifically relevant for each set of capabilities, while ensuring that the overarching considerations (e.g. treatment of data, integration into the AM process, etc.) are incorporated into both sets of criteria.

The following Figure illustrates the criteria comprising our first level of the framework, followed by a brief description of each individual criterion:

Overall Capability Sophistication Assessment		
Capability	**AA & ARA**	**RRM**
Assessment Criteria	1. Use of Risk-Based Analysis 2. Data Utilization and Management 3. Assessment Flexibility 4. Ease of Comprehension & Downstream Application 5. Clear Sense of Gaps & Improvement Plans	1. Integration into the AM Process. 2. Approach Definition. 3. Forecasting Complexity 4. Data Input Management 5. Clear Sense of Gaps & Improvement Plans

Figure 2. Overall Capability Sophistication Assessment

<u>AA and ARA Assessment Criteria:</u>

1. Use of Risk-Based Analysis – whether and to what extent a capability utilizes the key principles of risk-based analysis, as captured by asset management standards such as ISO 5500x, where risk assessment involves consideration of both probability and impact of asset failure.

2. *Data Utilization and Management* – the degree to which an AM capability / framework is supplied with electronic data inputs from a utility's enterprise systems and databases, such that the resulting AM analytical outputs can be updated in real-time and with little to no manual intervention. Within this criterion, we also assess whether an AM tool's outputs are expressed, in whole or in part, in a numerical form (such as

an index), to facilitate their subsequent consideration on balance with outputs from other AM tools and processes in a way that facilitates objective consideration.

3. *Assessment Flexibility* – the manner in which an AM framework balances the objectives of methodological consistency and flexibility required to account for the diversity of factors influencing asset performance across the different asset classes. While flexible approaches are generally preferred to "one-size-fits-all" frameworks, a successful approach will nevertheless exhibit meaningful features of discipline and consistency across all the individual asset classes.

4. *Ease of Comprehension and Downstream Application* – the extent to which the utility's staff and other key relevant stakeholders understand the nature, implications, and the manner of presentation of its outputs. While the AM analytics landscape is becoming increasingly more sophisticated, it is nevertheless desirable that the outputs of a given tool can be meaningfully explained and presented in a simple and transparent form, to ensure that its asset planners, managers and other key staff members involved in AM planning and implementation, understand the strategic objectives, operational mechanics, and methodological limitations of a given AM functionality, to enable consistent and objective decision making downstream from the tool itself.

5. *Clear Sense of Current Gaps and Continuous Improvement Plans* – whether and to what extent the conclusion of a discrete investment project, or a broader planning cycle involving an AM capability, includes a review stage to identify any functional or methodological gaps, and assess the plans for their rectification in the future. More generally, the utility deploying AM analytics capabilities should possess an understanding of their current gaps, while recognizing that continuous improvement of its asset analytics is necessary to ensure that AM decision-making continues to evolve.

RRM Assessment Criteria:

1. *Integration into the AM process* – the extent to which a given reliability forecasting capability is integrated into the utility's overall asset management process and the tools that support it, such that the forecasted reliability outcomes are functionally incorporated into the tools and processes that determine the scope, nature and type of intervention activities across the capital and maintenance programs.

2. *Approach Definition* – the breadth and granularity of analysis underlying the forecasting methodology, including length of forecasting horizons and source data periods, the extent of and methodologies used for data exclusions, along with the manner in which outage drivers are analyzed, and system components are modelled.

3. Forecasting Complexity – sophistication of mathematical calculations supporting the forecasting model, including the degree to which it utilizes empirically derived correlations between outage modes, durations, and performance of specific asset classes and other relevant phenomena (e.g. weather/climate, human errors, foreign interference, etc.).

4. Data Input Management – efficiency of data collection procedures, and the degree to which tools and processes are in place to optimize and validate the integrity of input data used in model calculations.

5. Clear Sense of Current Gaps and Continuous Improvement Plans – consistent with the framework for the AA/ARA functionalities, this criterion assesses the degree to which the utility conducts periodic assessments of effectiveness of the forecasting tool, develops plans for its improvement, and exhibits an understanding of the tool's key gaps, along with the expectation that continuous improvement is both necessary and desirable.

1.3.2. *Assessment Level Two: Technical Parameter Robustness*

The second level of assessment in METSCO's evaluation framework concerns only the AA and ARA capabilities for reasons noted above and further substantiated in the concluding parts of the Level 1 RRM assessment. Recalling that one of the categories of our Level 1 assessment of these two capabilities is the degree of flexibility applied to analysis of various asset classes, our Level 2 assessment reviews the AA and ARA frameworks from the perspective of six major asset classes that undergo analysis by these two frameworks. These asset classes are:

- Power Transformers
- Circuit Breakers
- Protection, Control & Telecom Infrastructure
- Station Ancillary Equipment
- Overhead Transmission Conductors
- Underground Transmission Cables

Building on findings from the Level 1 assessment, Level 2 review considers the key aspects underlying the evaluation of each asset class, including (as relevant) the nature and composition of asset condition parameters, the manner of application of additional analytical and diagnostic tools, and the related strategies, policies, and implementation plans. Similar to the first level of analysis, in assessing these and other related elements of Hydro One's AM capabilities on an asset class level, we make periodic references to the state of the broader utilities industry with respect to similar issues.

METSCO notes that unlike the first level of assessment, we do not employ a single set of evaluation criteria across the six asset classes we assessed, but rather discuss the issues that we see as most pertinent in every particular case.

1.3.3. *Assessment Level Three: Practical Application Issues*

The final assessment level in our three-step framework involved the examination of practical application of the AA and ARA outputs in Hydro One's asset management and capital planning processes. Following a substantive assessment of technical and operational matters in the previous two steps of the framework, METSCO's objective in the final stage was to examine a range of practical case studies that illustrate the manner and outcomes of Hydro One's actual utilization of the AA and ARA results in the course of making real-life asset management decisions.

In practical terms, we carried out this stage of our engagement by way of interviews and collaborative record reviews with Hydro One's Subject Matter Experts (SMEs) responsible for the Stations and Lines programs. In the course of these engagements, METSCO asked Hydro One SMEs to produce examples illustrative of typical process flow within AA and ARA frameworks, as well as examples where the insights from one functionality did not align with those generated by the other. In reviewing these mini-case studies we sought to examine whether their ultimate outcomes – that is the practical decisions as to the scope, manner and timing of asset interventions – were objective and logical from the perspective of Asset Analytics, and consistent with the intended objectives of the functionalities examined.

METSCO notes that the nature of our examination within this stage (and by extension, its findings) did not constitute a detailed audit, but rather amounted to a survey of representative examples, accompanied by contextual commentary from Hydro One specialists. Given the number of projects that comprise Hydro One's capital work program each year, the scope of our survey within this Level of assessment does not give us sufficient grounds for making any broad-based conclusions about the efficiency of the utility's overall capital investment plan. However, when examined alongside our findings from the previous two levels of assessment, Level 3 insights enable METSCO to conclude whether the technical elements of the capabilities examined and opined on in earlier stages, manifest themselves in practice in a manner consistent with their intended use.

In other words, while the first two stages of our assessment entailed a static review of key process dimension and individual mechanic components, Level 3 assessment is comparable to the examination of results of a live test run, where the combination and interaction of individual components produced outcomes in a realistic setting, shaped by Hydro One's organizational dynamics at the time that these assessments took place.

The remainder of this report provides a more detailed description of the three capabilities within the scope of this assessment and relays our findings across the three levels of assessment, concluding with detailed recommendations aimed at continuous improvement of the three capabilities.

2. Scope, Nature and Function of the Asset Management Capabilities Under Assessment

Prior to proceeding with our assessment, this section provides a more detailed explanation of the Asset Analytics, Asset Risk Assessment and Reliability Risk Model capabilities. With respect to AA and ARA in particular, and as noted earlier, the AA capability represents a distinct component of the ARA process, singled out for the purposes of this assessment given its role as a quantitative analysis "engine" positioned at the outset of the broader multi-component asset need identification process that ARA represents. Yet, the AA capability is ultimately a component of the broader ARA functionality, meaning that the assessment of the latter inevitably involves the assessment of the former. As such, for the purposes of our review, we discuss the two capabilities together, specifying where our comments concern one capability or another, where relevant. This chapter concludes with the description of the Reliability Risk Model to which we apply a distinct set of evaluation criteria.

2.1. Asset Analytics and Asset Risk Assessment Capabilities Overview

HONI's AA and ARA frameworks combine to form a crucial part of the utility's asset management process. Results from AA, which include the overall composite risk score, as well as the underlying sub-index components of this composite score (e.g. condition results), provide HONI asset managers and planners with an initial means of prioritizing the assets undergoing the assessment, subject to further evaluations.

Upon the completion of the AA analysis, Hydro One proceeds to perform further steps of the ARA procedure, supplementing the comprehensive numerical index and multiple component sub-indices generated by the AA capability with additional input categories generated through other processes, such as customer preferences, regulatory constraints, etc., in order to perform a comprehensive options analysis and establish a preferred risk treatment, that is, the specific scope and nature of recommended asset interventions.

Importantly, in the course of the ARA process, Hydro One also performs a number of verification and validation steps, including site visits, and other types of needs confirmation / screening tests to ensure that the analytical insights generated thus far, are reflective of reality in the field, and sufficiently robust to be incorporated into the final prioritization assessments, passed on further down the investment planning chain.

2.1.1. *Asset Analytics Capability Characteristics*

Asset Analytics is quantitative decision-support tool which analyzes the aggregated data supplied by various enterprise platforms (ultimately organized into a centralized data warehouse) in order to produce a series of quantitative indices based upon pre-defined criteria and methodologies.

The outputs of the AA process are a Composite Risk Score and a framework of individual analytical parameter Risk Score Sub-Indices, ranging from zero (lowest risk) to 100 (highest risk). These scores are derived for each individual asset. The sub-indices represent the following assessment sub-categories:

- *Condition*: considers the data on the physical state of assets and their core components along the relevant degradation factors expected to compromise the overall condition of an asset. Condition data used in the index development is sourced from field inspections, as well as Preventative Maintenance, Defect, and Trouble Call Reports, as relevant.

    - *Demographics*: Takes into consideration the assets' physical age in relation to its projected service life value or "Expected Service Life" (ESL), along with other demographic criteria like type, batch, manufacturer, etc. Hydro One defines asset ESL as the "average time duration in years that an asset can be expected to operate under normal system conditions and is determined by considering manufacturer guidelines and Hydro One historical asset retirement data." The ESL criteria for particular asset classes were derived from the results of a 2014 Asset Failure Analysis study conducted by Foster Associates, in which asset class-specific failure curves were validated using Hydro One's own historical failure data, and Iowa curve functions [3].

- *Criticality*: Takes into consideration the impact of failure at the individual asset, asset class, and station levels respectively. Input information for the formulation of this index includes factors like total customer load, voltage rating, critical customers and interconnections related to a given asset.

- *Performance*: Considers historical performance of a given asset, including the historical outage frequency and duration, as well as results from a Laplace trend test, which provide a measure of the difference in interval time between multiple forced outages.

- *Utilization*: provides the measure of asset deterioration related to the increased rate of asset utilization. Inputs such as the summer and winter peak loads, tap changer counter readings, and unit capacity data are used to formulate the index in this category for each asset.

- *Economics*: Takes into consideration the weighted average of emergency and corrective costs required to maintain the existing asset, as compared to the benchmark cost for the specific asset type/class.

Each of the AA evaluation category sub-indices, along with the overall composite score, contain references to "risk-based" calculations, incorporating parameters related to "probability" and/or "impact" of asset failure.

In cases where not all data input points underlying the indices are available, the AA tool can still produce a normalized evaluation category score, adjusting for the missing data. Every input data parameter used in the formulation carries a flag to indicate the status of data availability. A "Normal" flag indicates that the data is available to fully support the calculation. A "Default" flag, however, means that the input data parameter is missing, and has been substituted with a standard default value defined by HONI's subject matter experts. Finally, a "Missing" flag indicates where the input data parameter is missing, and no default value is available for substitution.

To account for these flags and the data gaps they represent, the AA functionality generates a Data Completeness Score – expressed as a percentage – to indicate to the end user how many actual and default supporting factors were used in the derivation of an index score. The system also generates a confidence level (expressed as a percentage), to indicate the degree of confidence in the calculated score, given the relative significance of the individual index parameters where data is missing, or a default value is in use. Critically, the flags and data completeness / confidence scores enable Hydro One staff to exercise additional judgment when assessing the AA outputs on balance with other inputs in the subsequent stages of the ARA process.

METSCO notes that not each of the six evaluation sub-indices is used in the generation of a Composite Risk Score for all asset classes, reflecting the relevance of a particular risk sub-category to a given asset class. Moreover, in the case of Protection, Control & Telecommunications assets, the AA framework is not substantially utilized in the ARA process, for reasons discussed further in this report.

The following section describes how the AA outputs, once generated in accordance with specifications related to each asset class, undergo further assessments in the subsequent stages of the ARA process.

2.1.2. *Asset Risk Assessment (ARA) Capability Characteristics*

Asset Risk Assessment (ARA) entails a full-spectrum asset management planning process that identifies the asset candidates to be included in the scope of the investment projects, of which AA is an input component used in conjunction with other input parameters, including:

- Asset class strategy and technical assessment documents, which utilize AA results and underlying data points in their analysis;
- Customer needs and preferences related to particular asset classes;
- Legal and regulatory requirements relevant for consideration;
- System planning and coordination requirements affecting potential intervention options;
- Health & Safety, environmental, and obsolescence-related;
- Field inputs, maintenance notifications, and relevant event investigations;
- Results of detailed assessments and diagnostic testing; and
- Field visit validation of asset needs suggested by ARA analysis.

Figure 3 illustrates the entire scope of the ARA process.

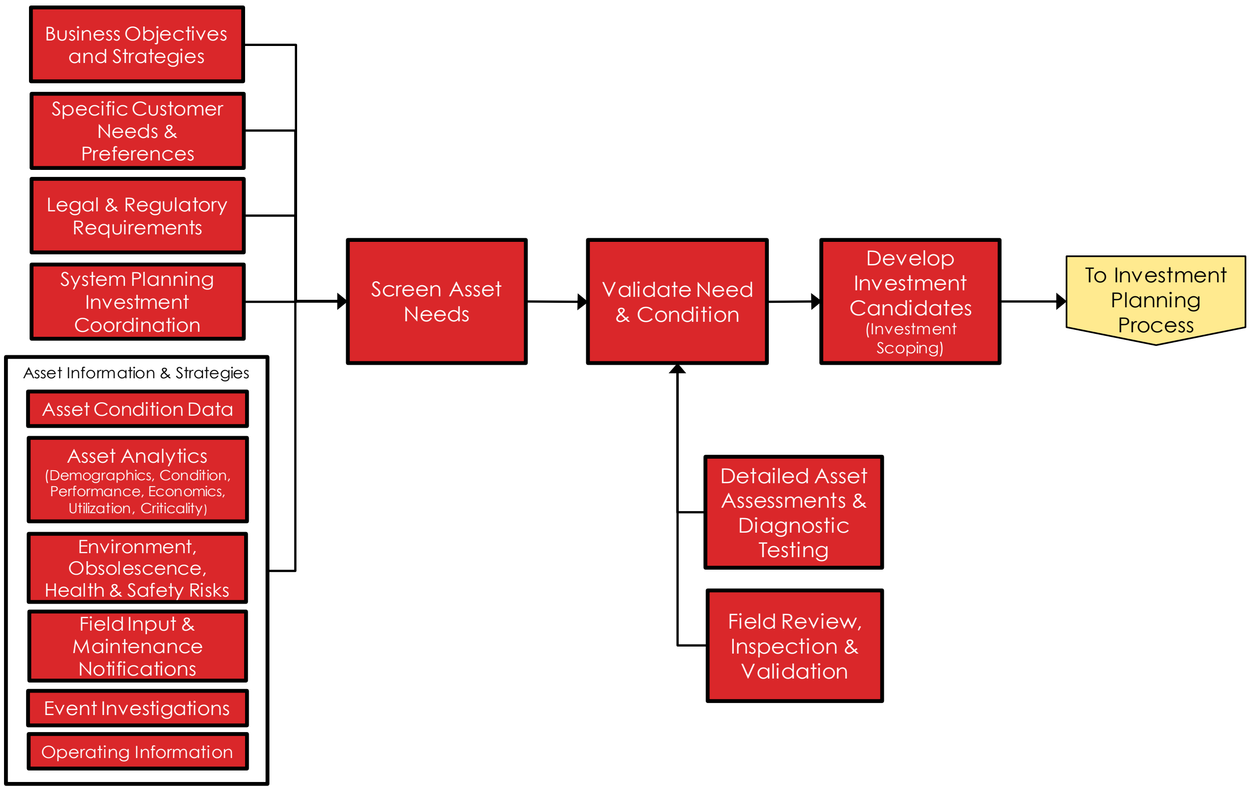


Figure 3. Asset Risk Assessment Process

Overall, the ARA functionality serves to expand upon the initial prioritization as established by AA, by allowing asset planners and managers to assess and stress-test the insights produced by the AA functionality in the context of incremental data points, and considerations that connection field data with the broader strategic, planning, and regulatory environment in which Hydro One operates.

2.1.3. *Reliability Risk Forecasting Capability Characteristics*

Reliability Risk Model is a standalone tool designed to develop system-level forecasts of changes in values of reliability risk relative to the capital investment levels underlying a particular scenario. METSCO understands that up to this point in its existence, the RRM's outputs were only used in the context of customer engagement meetings, to represent directional implications of reliability risk relative to the range of investment levels contemplated by the utility.

Given its current utilization, the tool and its outputs help contextualize Hydro One's investment considerations to customers, acting as a supporting mechanism in gathering customer feedback that is considered in the course of investment planning. With the exception of this indirect contribution into the investment planning activities, the tool and its outputs do not currently figure as input factors at any stage of the asset management process. For clarity, METSCO understands that the RRM analysis only takes place after the AM decision-making processes – including the use of AA and ARA capabilities – has been completed.

From a functional perspective, the RRM tool is grounded in failure probability curves derived in an aforementioned 2014 Asset Failure Analysis report [3], and asset demographics data of select asset classes. Using this data, the model ultimately predicts the age profile of assets over the forecasting horizon. Based on the replacement budget assumptions (i.e. the input investment scenario), the model then establishes links between investments and reliability risk.

Having described the tools within the scope of METSCO's assessment, the next chapter of this report contains our discussion of our findings with respect to the AA and the ARA functionalities.

3. Asset Analytics and Asset Risk Assessment Capabilities Evaluation

We begin the discussion of the findings of our assessment with the first system-level analysis across the following five criteria: (a) Use of Risk-Based Analysis; (b) Data Utilization and Management; (c) Assessment Flexibility; (d) Ease of Comprehension and Downstream Application; and (e) Clear Sense of Gaps & Improvement Plans.

Upon completion of the first Level of analysis, this chapter turns to the asset-class specific considerations affecting the use of AA and ARA capabilities, and finally, the results of our observations of the functional test cases showcasing the AA and ARA capabilities in action.

3.1. Level 1 Assessment: Overall Capability Sophistication

3.1.1. *Use of Risk-Based Analysis*

At the outset of this section, METSCO notes that Hydro One's process nomenclature uses the term risk extensively (including in the name of the ARA process undergoing assessment) to denote a variety of potential conditions, incidents, and contingencies that could potentially bring about adverse consequences to the utility's assets, systems and operations.[1] While we do not dispute the validity of Hydro One's use of the term "risk" and generally endorse the wide array of factors that the utility considers within its asset-related risk universe, we note that the definition of "risk" underlying this particular criterion of our assessment framework carries a particular meaning, consistent with the ISO 5500x asset management frameworks referenced in the criterion's definition.

In this context, the notion "risk" entails a single quantifiable number that combines the quantitative expressions of probability (%) and impact of an asset's failure expressed in numerical terms (e.g. outage impact that may be expressed in monetary terms) as a multiplication between the two parameters. Such an expression of risk (or risk costs) is considered to be an asset management best practice since it captures both likelihood and consequence of failure in a single numerical value – making prioritization across individual assets, asset classes, or intervention options both simpler and more transparent.

[1] We note that this is METSCO's formulation, established by way of our incremental interviews with Hydro One SMEs, rather than a definition in use at the utility.

When reviewing Hydro One's AA and ARA capabilities, we found multiple instances where failure probability and impact calculations are factored into the derivation of the AA Composite Index and its sub-components. For instance, elements of probability analysis are deployed within the calculation of the "Demographics" sub-category, which utilizes ESL criteria and failure curve calculations in deriving the sub-index score.

Similarly, parameters pertaining to probability of asset failure are present within the "Performance", "Utilization" and "Condition" evaluation category approaches. The "Criticality", "Utilization" and "Performance" categories similarly contain components that relate to the impact of Asset Failure. Of these, the "Criticality" sub-index is particularly notable from the perspective of failure impact, as it measures the relative importance of a given asset on the system in light of its electrical position relative to customers and other system components. As such, the Asset Analytics capability contains multiple elements that consider the probability and impact of asset failures, with the former largely tied to the asset condition-related criteria typically found in standalone Health Index formulations, and the latter grounded in system criticality of a particular asset, the economic considerations of proactive vs. reactive failure, etc.

While all of these risk-related factors are ultimately present in the expression of the final Composite Risk Score and individual Sub-Indices, at no point in the calculation process is risk explicitly expressed as *Failure Probability* × *Failure Impact*. Importantly, the fact that Hydro One's framework does not utilize the more commonly adopted expression of risk associated with leading technical standards, only implies than the manifestation of the relationship between the quantitative probability and impact-related elements of the Hydro One AA approach is less clear and more complex (in light of the presence of multiple other factors in the calculation of the index) than it otherwise could be. It does not, however, indicate that the model lacks quantitative considerations of probability and impact of failure into its calculations.

Accordingly, while the way the AA capability crystalizes the notion of risk are not fully aligned with the "model-derived" risk notion characterizing industry leaders, Hydro One's risk-related capabilities are nevertheless materially ahead of the more simplistic, and/or not fully quantitative asset risk definition methodologies that continue to be employed by most electric utilities in Canada and North America.

Elements of risk management and validation are also present throughout the broader ARA framework, where additional criteria related to environmental, safety, legal and other types of risks undergo assessment alongside the results of the AA capability. Ultimately, however, the comparison of AA outputs – expressed as non-dollar indices –

with the risk definitions established through other ARA inputs, is more complicated, and less intuitive than it could have been had all units were defined in numerical (preferably monetary) terms, as outcomes of Probability × Impact calculation. This representation of risk implies that the criteria comprising the assessment of asset failure Probability are clearly separated from the criteria comprising the Impact assessment if the asset failure occurs.

Accordingly, while we acknowledge the quantitative definition and application of risk principles within the AA and ARA frameworks differs from those used by other utilities, we are confident that Hydro One's current capabilities within this area place it in line with, or ahead of the majority of Canadian electric utilities. Modest incremental adjustments to the AA framework to clearly define asset probability and impact would place the utility within the best practice utilities.

Based on our findings, METSCO provides the following recommendation:

- Consider clearly separating the risk factors/criteria in AA to define probability of failure of a specific asset, and the impact of asset failure to explicitly assess a broader variety of outage consequence costs, such as utility's and socioeconomic costs, including the costs associated with the environment, safety/collateral damages, environment, customer interruption costs and financial impacts.

- In making the above recommendation, we are cognizant that many of these components are already included and evaluated as a part of the broader ARA process. As such, these potential enhancements should be considered only at the juncture where HONI may consider a more fundamental reorganization of asset management processes.

3.1.2. Data Utilization and Management

Data integration and automation of interfaces between key utility processes continue to pose challenges for many utilities in the context of asset management. This is largely the case given that many processes that generate inputs for asset management analytics occur in isolated and siloed manner, often using incompatible and/or non-electronic formats for capturing the data. Hydro One, however, is a notable exception to this common tendency given the utility's system integration advancements in the recent years.

As illustrated in Figure 4, the AA capability automatically retrieves all of its input data from a series of enterprise systems across HONI's network, centralizing it in a single data warehouse.

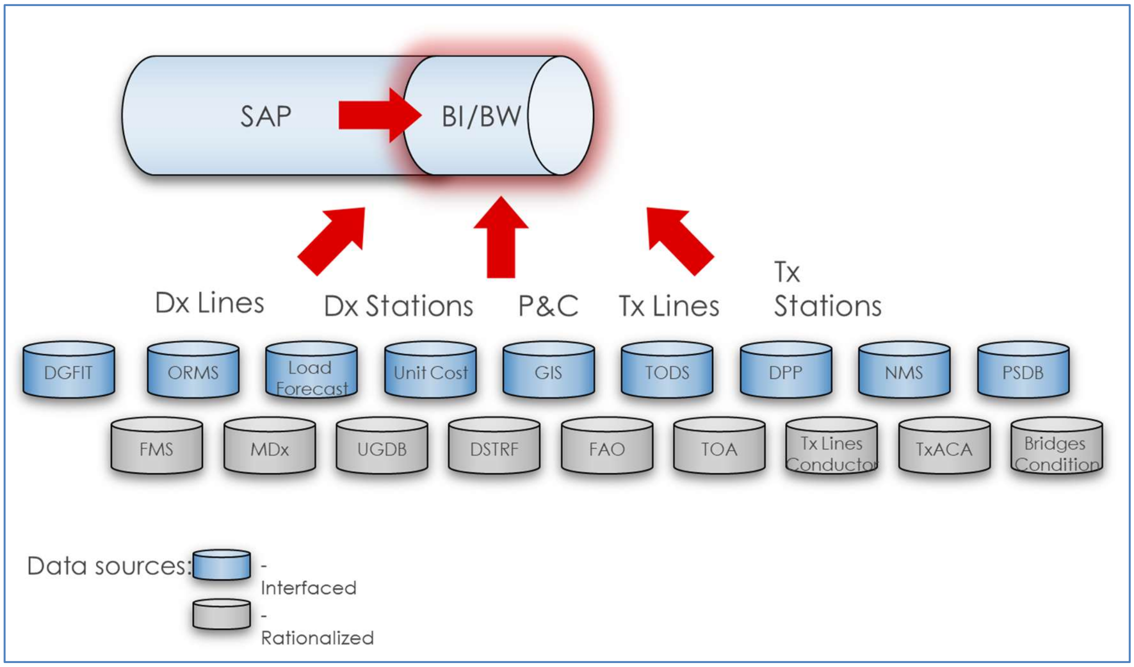


Figure 4. Data Sourcing for the Asset Analytics Capability (HONI Illustration)

The data is automatically updated on a weekly basis, as well as whenever any changes to the transmission system are reflected in the source IT systems. Importantly, once the AA analysis for a given procedure involving a group of assets is completed, its results are also automatically stored back into the SAP system. The completed results can be visualized through the utility's Space-Time Insight (STI) software, which places the assets in question in geographical context and enables disaggregation of the Composite Index into its six sub-components, as showcased in the figure below.

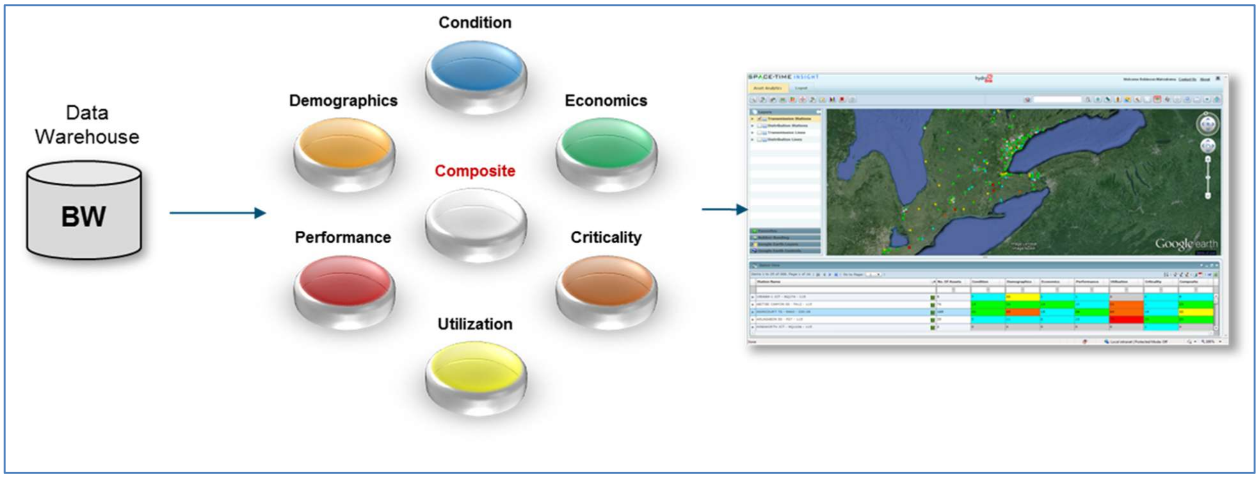


Figure 5. AA Results Storage, Retrieval and Visualization Through HONI IT Capabilities

Notwithstanding our earlier comments regarding the specific numerical form in which the AA outputs are presented, the fact that they are presented in the manner of a consistent quantitative index is in and of itself a decidedly positive feature, as this manner of presentation ensures that the subsequent consideration of outputs will be consistent across different stages of the ARA process, or different individuals conducting further assessments and diagnostics.

Equally notable is the presence and consistent utilization of the data completeness "flag" system and confidence score framework described in Section 2.1.1. Differentiating between the AA output indices where all requisite data is present, those where some inputs are filled with default settings and those where certain data is missing outright, the flag system and data confidence score framework unambiguously alert the asset management personnel conducting the ARA process of potential issues underlying a particular index calculated through the AA framework.

While we see the manner in which Hydro One alerts its staff of the instances of incomplete data as unambiguously positive, the instances of data unavailability themselves constitute a continuous improvement opportunity – for Hydro One and virtually every other utility. While our assessment's scope did not include any data accuracy verification checks, we generally see the overall scope and diversity of data inputs that Hydro One incorporates into its AA and ARA processes as a reasonable mitigation step in the instances of missing data – ensuring that the ultimate prioritization outputs are robust and reflective of a multitude of sources.

METSCO understands that Hydro One is undertaking a number of initiatives to improve the quality and completeness of its data. Although we thoroughly endorse these endeavors, we note that in pursuing them on a large scale, Hydro One should consider the opportunity costs of resources expended in the course of such projects. This consideration is particularly relevant with respect to the large populations of assets that Hydro One can reasonably expect to replace on the basis of their condition or other relevant factors in the next few years. Since all of the information related to the replacement assets would be stored in the systems, Hydro One may choose to carefully examine the value proposition of interim efforts to replenish the current records for older asset vintages.

On balance of the above-noted factors, METSCO concludes that Hydro One's data utilization and management practices are consistent with industry best practices and are substantially ahead of most Canadian utilities. This is largely because the assessment processes are quantitative data-driven, while the instances of reliance on manual data handling (which are both inefficient and carry the risks of human errors) are minor.

3.1.3. *Assessment Flexibility*

In light of the number of discrete asset classes, models, vintages and other unique or cohort-specific features related to assets that comprise a typical utility's system, any asset management /analytics methodology should embed a reasonable amount of flexibility to manage the adverse implications of any "one size fits all" approaches. As we elaborate in our description of our Second, asset-class specific Level of assessment, we found Hydro One's AA and ARA frameworks to be appropriately flexible and modular to account for relevant asset-specific considerations.

Aside from the utilization of asset-class specific condition parameters, failure curves, equipment performance thresholds, etc. inherent in the design of the AA capability, a crucial factor that facilitates flexibility of assessment is the sole existence of the ARA process that incorporates a variety of additional assessments relevant to a particular type of assets. While the overall purpose and nomenclature of the steps and stages comprising the ARA process are considered to be standard across the asset classes (see Figure 3) the form and specific content examined in the course of these assessments depends on the key performance characteristics of a particular asset class.

For instance, in the course of the ARA process for stations assets, Hydro One produces and/or updates a Station Assessment Document, which along with the AA-derived index value, considers such factors as reports of stranded load risks, capacity constraints analysis, loading stability assessment, short circuit levels, PCB-related issues of any oil-filled assets, station security concerns, and a number of others.

While it supplements Hydro One's asset management process with a degree of flexibility, ARA functionality also contains features like asset needs screening and field review validation, which provide a degree of rigour and discipline to the overall process, to ensure that the lists of asset needs produced at the end of the process are generally robust and reflective of operating reality. Combined with the data-centric nature inherent in the AA functionality, these process steps facilitate a degree of consistency and discipline that balances the considerations of flexibility.

In consideration of the above-noted factors, METSCO finds that Hydro One's AA and ARA capabilities embed an appropriate degree of assessment flexibility, balanced with overall procedural discipline that may be expected of a robust asset management framework.

3.1.4. *Ease of Comprehension and Downstream Application*

It is important not to underestimate the importance of a utility's asset management and investment planning staff possessing a clear and comprehensive understanding of the asset management capabilities' purpose, methodology, limitations, and implications of their results. In METSCO's assessment, possessing this understanding is equally important for staff operating in the areas conducting AM assessments, and their counterparts performing downstream tasks that rely on the outputs of these assessments. Absent this understanding across the relevant organizational units, the system's operation and utilization of its outputs may carry a number of risks that can compromise the accuracy of the results, compliance with process steps, or even particular courses of action suggested by the results of AM analysis.

In the course of conducting our interviews with Hydro One's asset management staff and management, METSCO found that they possessed a clear and in-depth understanding of the AM process as a whole, and the AA/ARA functionalities in particular. In most cases in METSCO's experience, only a small group of individuals within a utility may possess the specific knowledge of the AM analytics and implications of their results. In Hydro One's case, however, we found that the methodologies were clearly understood by most professional AM staff. Most importantly, the understanding of the frameworks' crucial elements appeared to be consistent between the different asset managers, planners and groups responsible for executing particular process steps or managing performance of certain asset classes.

While this finding generally positions Hydro One well for consistent and accurate application of the AA and ARA principles to its asset base, METSCO does have concerns in this area. Chief among them is the fact of the sheer complexity of the frameworks, particularly in the case of AA capability, where the assessment results are at once presented as a single index, and six component sub-indices, each reliant on unique sub-processes, assumptions and calculations, the impact of which in not readily apparent when reviewing the aggregated index results. While the AA capability enables asset managers to disaggregate the composite index into its individual components (allowing, for instance, for asset condition data to be extracted separately for a detailed assessment), we view this procedure as somewhat cumbersome to any person not deeply involved in the process.

Moreover, the methodological disaggregation of AA analysis into six discrete "pre-final" sub-indices and its subsequent incorporation into the ARA process containing other major data points, increases the conceptual complexity of the entire process, when assessed by an outside party (including METSCO staff who reviewed these processes). Considering that most of the six discrete AA risk variables / sub-indices are commonly expressed as components of a single Asset Health Index variable (a well understood industry term, which along with condition of asset components typically includes data like loading levels, demographics, etc.) Hydro One's nomenclature and the manner of derivation of its AA formula is, in our assessment, more complex in its presentation than it could be.

The potential impact of this consideration is somewhat amplified by lacking documentation practices with respect to formal explanatory literature on the scope and nature of detailed analytical steps comprising the AA and ARA functionalities. In discussing this issue with Hydro One, METSCO understands that this is in large part a product of the rapid evolution of successive asset management capabilities in recent years – the fact that the utility also indicated in its previous transmission rate application.

Although the observed difficulty of initial comprehension is not a concern for the utility's current staff that are well versed in the process mechanics, we believe that the present formulation carries a risk of being initially misinterpreted or misunderstood when explained to a new employee, a contractor, a party in a regulatory proceeding, or a peer utility in the context of best practices sharing.

On one hand, we were impressed with both the depth and consistency of the current staff's understanding of the processes, their implications and methodological limitations. On the other hand, however, it took METSCO considerable effort to fully internalize the nature of certain AA and ARA components, and reconcile them with approaches used elsewhere in the industry. Accordingly, we conclude that the downstream application of the outputs of AA and ARA processes is relatively straightforward within the context of Hydro One's current organizational structure and staffing complement. However, we find that the methodologies underlying the frameworks are moderately difficult to comprehend, which presents potential risks in the context of internal knowledge transfers, or best practices sharing.

To conclude the assessment of the Ease of Comprehension and Downstream Application, METSCO provides the recommendation that is similar in nature to the Use of Risk-Based Analysis:

- Re-visit the present formulation of the AA framework components and consider potential regrouping / renaming of assessment factors to better align it with commonly understood industry terminology (such as condition assessment/health index, or impact assessment/consequence cost), and take steps to develop more comprehensive explanatory manuals for its AA capabilities.

3.1.5. *Clear Sense of Current Gaps and Continuous Improvement Opportunities*

In our discussions with Hydro One throughout the duration of this engagement, we found the utility's staff to be cognizant of the current systems' limitations, receptive to the feedback provided by METSCO, and motivated to undertake further enhancements to its asset management capabilities. We note that the utility has clear governance protocols for identification and management of the identified gaps, which includes the aforementioned data completeness flag and confidence score frameworks, along with periodic initiatives aimed at enhancing the system's analytical robustness. For instance, METSCO understands that Hydro One is in the process of procuring professional services to enhance certain aspects of its AA algorithms, while also taking steps to address the findings of the recent successive Internal Audit reviews.

Overall, while our engagement highlighted the sense of pride in the existing analytical capabilities and the processes that support them among Hydro One's engineering and planning staff, this sentiment was invariably balanced by the realistic assessment of the systems' status quo issues, and genuine curiosity as to the practices employed elsewhere in the industry. Accordingly, we find Hydro One's understanding of current gaps inherent in their systems and plans for continuous improvement opportunities to be reflective of a utility committed to continuous improvement.

3.2. Level 2 Assessment: Technical Parameters Robustness

Having completed the first level of our assessment, this section examines the AA and ARA capabilities from the perspective of tests, diagnostics and assessment applied to individual asset classes that the capabilities evaluate. To accomplish this, METSCO examined the scope of input data and the analytical methodologies applied to derive the AA Composite Risk Index for each of the evaluated asset classes. We also reviewed the input information supporting the broader ARA procedure, along with the strategic and operational documents, developed on the basis of, and in the course of collecting the insights generated through the ARA process.

In this context, our review of asset class-specific information considered in the scope of AA and ARA assessments is structured around three issue areas (where they are relevant), namely:

- *Input Data Supporting the AA Framework*: Integrity of the inputs used to support the AA framework, by measuring the sample sizes of the data that was utilized.

- *AA Evaluation Score Criteria & Results:* Completeness of the criteria used and methodologies applied to support the evaluation category scoring results.

- *Asset Risk Assessment Components*: Assessment on the incremental inputs used in supporting the ARA procedure, including strategic and operational documents.

We supply our observations and recommendations grounded in our in-depth review and assessment within each subsection.

3.2.1. Station Power Transformers

Input Data Supporting the Power Transformer AA Framework

The Asset Analytics formulation for Station Power Transformers leverages all six evaluation categories (i.e. Demographics, Condition, Performance, Utilization, Economics, Criticality) in order to produce an overall composite risk score. Our review of data availability across all input variables supporting each evaluation category score, suggests that on average, approximately 80% of requisite data entries across evaluation categories are populated with actual data, the remainder being supplied by default scores devised by SMEs, and/or missing. Figure 6 illustrates the average data availability across the inputs for each evaluation category[2].

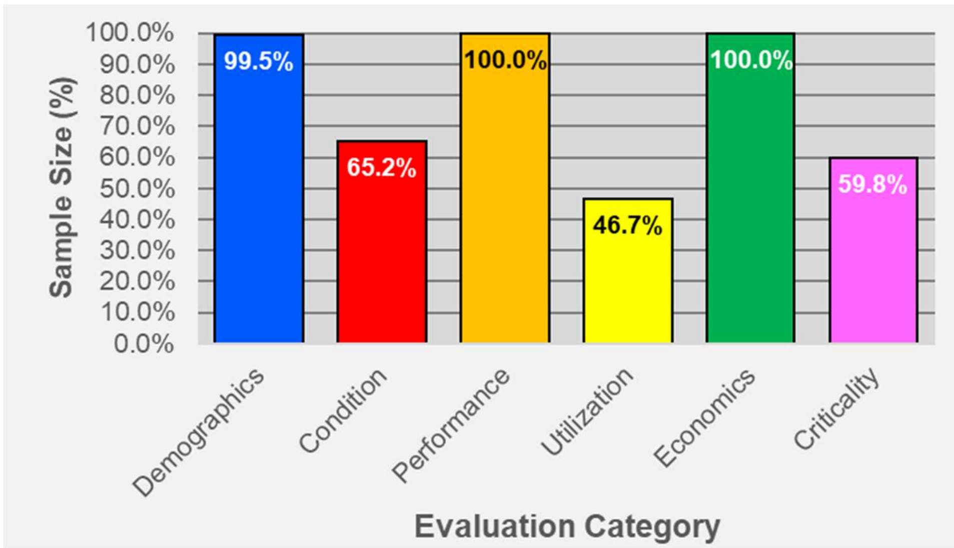


Figure 6. Station Power Transformer Average Sample Sizes for each Evaluation Category

On balance, METSCO finds that the average data availability levels across all six categories is satisfactory to make inferences and construct sub-indices for further evaluation (recall that the AA capability generates flags and scores to indicate missing or default data to notify asset managers where caution is required).

While the actual Condition data availability score of 65.2% may seem insufficient, METSCO finds it to be robust, considering the size of HONI's asset base, the span of its territory, and the manner of presentation of the condition score relative to many other utilities. Notably, and unlike most condition scores that feature in rate applications in the form of Health Indices (HI), Hydro One's condition data availability score does not include any age or utilization data (each captured in their separate demographic category), which are often included in Health Index formulas and are used (correctly) to represent discrete facets of asset health. Instead, the condition captured within HONI's Condition category is related solely to data on asset's extent of degradation, as assessed by Hydro One's field crews, and established by empirical tests like Dissolved

[2] The overall data availability score referenced above was calculated on the basis of average across all individual input values in all categories - not across the averages of each individual category

Gas Analysis (DGA). When assessed in this important context, the amount of condition-based information available for this critical asset class is substantial.

We also note that the relatively low scores across some of the six categories are a function of the number of parameters that HONI is seeking to track in the ideal circumstances and is making steps to acquire the data for. In METSCO's assessment, a lower availability score as a result of seeking to track more individual variables is more preferable that a high availability score that reflects one or two parameters only.

Notwithstanding these observations, data gaps are present, and we recommend HONI to:

- Continue to mitigate the data gaps as part of continual improvements, such that the sample sizes of evaluation categories (and overall sample size within AA) can continue to improve over time.

It should be noted, however, that all power transformer assets ultimately receive an evaluation category score as well as an overall composite risk score through the use of the data completeness procedure as discussed in Section 2.1.1.

Power Transformer AA Evaluation Score Criteria & Results

Each of the evaluation category scores for power transformers contains references to "risk-based" calculations, in which these variables refer to either the "probability" or "impact" of asset failure.

The demographics score, for instance, contains probability-related elements, as it compares the transformers existing' age to its ESL criteria, defined by the failure curve study performed by Foster Associates [3].

The Condition evaluation category score for power transformers also includes probability-related elements, taking into consideration the following criteria:

- Dissolved gas analysis (DGA) testing results;
- Furan analysis results;
- Doble testing results;
- Defect report and trouble call notifications.

The Utilization evaluation category score takes into consideration the loading and usage that the transformer has experienced, including the summer and winter peak load, 10-day limited time rating (LTR), tap changer counter reading and maximum number of operations – all of which represent an extension of condition-related components and relate to the assets' probability of failure. This score also accounts for the capacity of the transformer, where a higher risk score is assigned to a greater size of transformer, which would relate to the assets' impact of failure.

The Performance evaluation category score takes into consideration historical performance associated with the power transformer, including frequency and duration of forced outages, as well as the Laplace trend test designed to measure the difference in internal time between the forced outage occurrences. An increasing Laplace trend, coupled with decreasing interval times between outages, indicates that the condition of the power transformer is worsening. As is the case with demographics, condition and utilization, this result represents further insight into the assets' probability of failure.

The Economics category scoring accounts for the ongoing costs to manage the power transformer when a problem emerges, including emergency and corrective costs that would be associated with historical failure events. While the economic score may include the costs already taken to refurbish the transformer, typically it represents the ongoing costs of maintaining the transformer in the current fleet.

The Criticality evaluation category assigns a criticality score to the evaluated power transformer based upon the station that it is installed within, the type of power transformer as well as the individual asset voltage rating, MVA rating and single point of vulnerability.

Both the Economics and Criticality scores relate to the impact of asset failure or the impact of the asset continuing to require significant on-going spending to maintain the transformer in service.

As probability and impact components are identified within the individual evaluation scoring categories and criteria, the final output from the AA framework is representative of the overall risks applicable to the asset. However, when viewed on its own, the produced composite risk score for power transformers can be complex to understand, due to the integration of probability and impact components into a singular value. It is notable, however, that the underlying evaluation category results are modular and can be extracted as part of further analysis within the ARA procedure.

While this unnecessary score complexity is applicable to the other asset classes, the recommendation to integrate commonly employed variables for risk-based calculations is discussed in Section 3.1.4.

With respect to condition evaluation, HONI's current scoring considers the most critical testing results performed by utilities, such as DGA, Furan and Doble testing. However, METSCO recommends that HONI integrate the additional condition parameters which it already collects and applies as a part of the ARA process directly into the AA framework:

- Condition of cooling system, including radiator and fans;
- Condition of gaskets and seals;
- Condition of transformer tank;
- Foundation condition;
- Condition of connectors.

It is also notable that certain inspection parameters are considered as part of the condition scoring, but are integrated within other categories rather than individually scored and weighted. As an example, the Condition category contains a scoring parameter relating to historical defect report notifications, which can contain underlying inputs such as bushing/support insulator inspection results and infrared scanning results. As part of continual improvements, we recommend that HONI consider breaking out these parameters in order to introduce a more transparent calculation.

Overall, when examining the "highest risk" power transformers, as prioritized through the AA Composite Risk score result, we observed that the composite results reflected the underlying inputs, providing reasonable indications across the criteria. As an example, the highest-risk power transformer on the list was (a) past its ESL, (b) had a very poor condition score; and (c) had sustained a series of outage events over the past five-year period, which precipitated extensive and costly corrective and emergency repairs within that time period.

We observed similar findings for the 20 highest priority (in terms of overall risk) power transformers – the majority of which were found to be past their ESL and having encountered some form of performance issues over the past five-year period along with corrective and emergency costs.

Power Transformer ARA Analysis Components

As part of the ARA process, HONI supplements AA-generated scores with a range of additional data inputs. The combination of these factors informs the utility's power transformer strategy and technical assessment documents, which underlie its long- and short-term decision-making for a given asset class, respectively. METSCO examined these documents and discussed their content with HONI SMEs, as a means of establishing the scope and nature of additional information comprising the ARA review.

METSCO found HONI's power transformer strategy document to further supplement the AA framework results with incremental analysis conducted for each of the six evaluation categories as a part of the ARA process. Key additional parameters considered in the strategic document include:

- Demographics: Demonstrating the current and future replacement needs through assessment of units that are currently beyond their expected service life, along with their projected failure rates as derived from HONI's failure curves.

- Condition: additional assessment of operating considerations related to power transformers diagnosed to have specific condition-related issues, such as poor DGA results and oil leaks.

- Performance: Assessment of historical reliability events, including outage frequency, outage duration, frequency of asset component failures (e.g. transformer core, cooling equipment, auxiliary equipment, windings, etc.) and oil leak events (separating major and minor leaks).

- Utilization: Discussion of Summer and Winter 10-Day Limited Load capabilities across the utility's transformer fleet.

- Criticality: Discussion of critical customer types, design and voltage-related criticality impacts on these customers, along with environmental impacts.

- Economics: Discussion of economic impacts, including financial impacts to utility and socio-economic impacts to customer (e.g. customer interruption costs).

Figure 7 illustrates an example of the incremental information captured in HONI's strategy document and collected as a part of ARA - in this case with respect to transformer oil leaks across the fleet. Oil leakage information represents a significant indicator of the overall degradation and failure of a power transformer. As such, while it is not captured in the AA score, this critical information is nevertheless integrated into the decision-making process prior to concluding asset prioritization work.

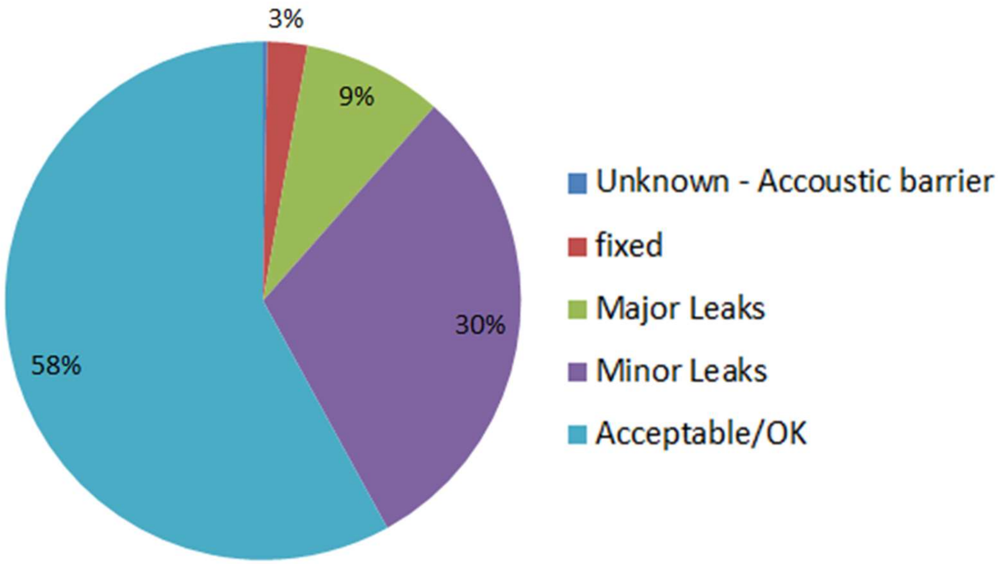


Figure 7. Hydro One Transmission Class Overview – Leak Overview [4]

The strategy documents also include additional risk factors as identified within the ARA process to further assess the need for and prudence of power transformer replacements, including obsolescence, safety and environmental impacts. Throughout this document, HONI articulates the processes applied in order to capture this input data (e.g. process for condition assessment) and also explains the consequences of no action taken (e.g. projected failure rates).

Key ARA outputs reflected in the strategy document include the master list of power transformers recommended for replacement intervention, along with strategic recommendations for how existing risks can be mitigated into the future.

In addition to strategy documents ARA assessment results also drive the development of technical assessment document produced for individual power transformers. These individual assessments provide an even greater granularity of information as to the current risks associated with individual asset, along with incremental justification of intervention. These information categories include:

- Demographics: Age of the evaluated asset when compared to its ESL as well as overall demographics across all power transformers.

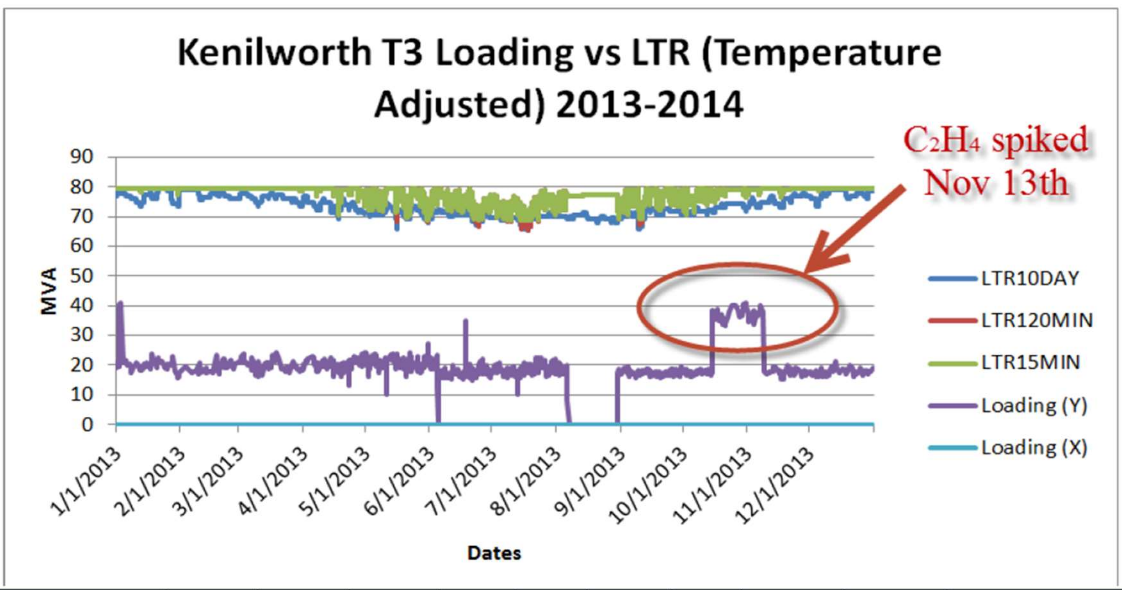
- Condition: Detailed discussion on individual testing results concerning the transformer, including findings of oil analysis (DGA), moisture analysis, oil leaks (with photos), infrared scanning results (with photos) as well as maintenance history, trouble calls and deficiency reports.

- Environment: Spill risk assessment and discussion on recent PCB testing results.

- Equipment Loading: Detailed year-by-year assessment of historical loading on power transformer versus limited time rating (LTR) limits.

- Economics: Breakdown of historical spending required to maintain the evaluated transformer, including OM&A spending.

Taken as a whole, the information noted above is used to identify serious issues that drive justification for the need and prudence of short-term intervention. An example of this is illustrated in Figure 8, where results from a yearly load profile on a particular power transformer identified a spike in loading, which was subsequently correlated to the gassing pattern as identified from the DGA analysis results.



Date	C2H2	C2H4	C2H6	CH4	CO	CO2	H2	N2	O2	Total Dissolved Gas (%)
08/29/2012	0	70	13	19	227	1870	0	67900	28700	9.84
11/13/2013	0	143	22	69	246	2130	20	70900	32100	10.51
01/31/2014	0	148	26.5	69	217	1735	30	64400	28400	9.5

Figure 8. Establishing Correlations between DGA Results and Load Profiles [2]

The technical assessment document concludes with a net present value (NPV) analysis, where different options (e.g. status quo, repair/refurbish, replacement) are compared and contrasted with each other, using the annual investment requirements as an input for each investment option in order to identify the preferred option that yields the lowest NPV result. An example of this assessment is illustrated in Figure 9.

Overall, through the technical assessment for power transformers, METSCO confirmed that HONI's decision-making does not simply rely upon the AA index results but in fact moves far beyond these scores using detailed incremental analysis of quantitative factors. As such, the ARA analysis serves to further justify the final decision to be made. Further examination of the input data supplied by AA into the strategy and assessment documents serves to validate the results of the AA framework and results, ensuring that intervention decisions consider a broad array of quantitative information.

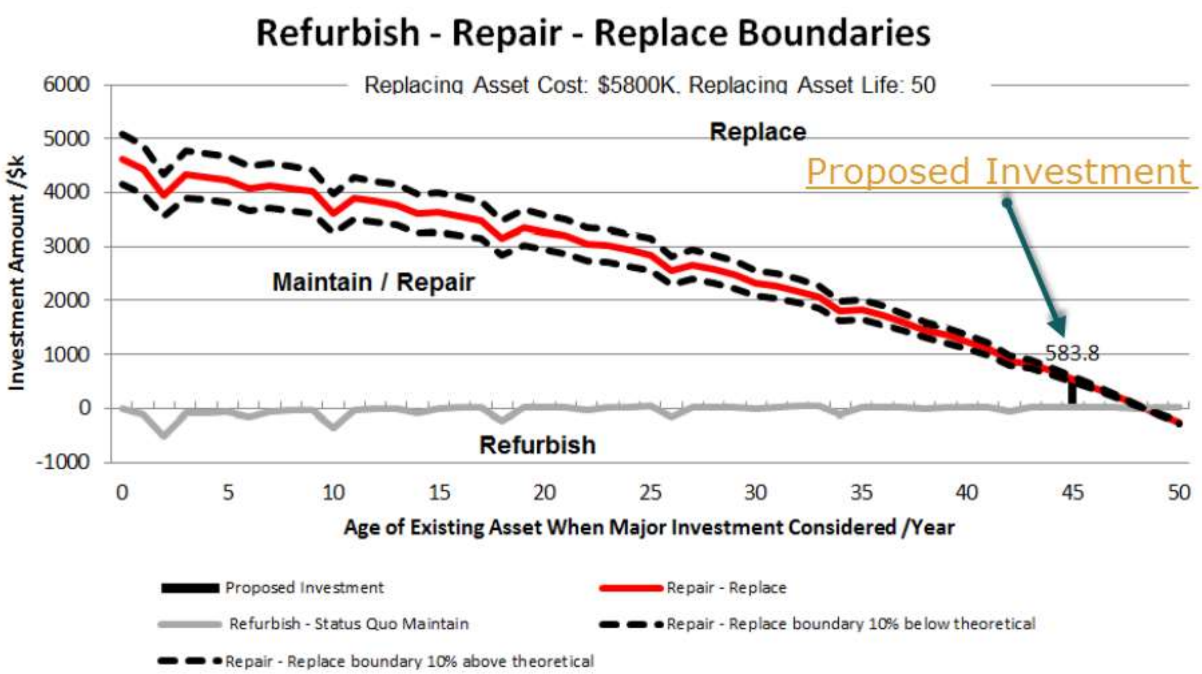


Figure 9. Net Present Value Comparison of Different Investment Options [2]

As a part of continual improvement, METSCO recommends HONI to:

- Consider integrating useful incremental asset data that exist outside of the current AA score (e.g. environmental and safety factors, along with other condition information types) directly into the condition evaluation category scoring as part of the AA framework, should HONI contemplate a substantial upgrade/reorganization of its AM processes.

- Consider integrating broader socio-economic factors into the evaluation, including costs to the customer (customer interruption costs), as well as environmental and safety-related monetary cost factors, such that the full range of economic costs (including those that go beyond those incurred by a utility or its customers).

3.2.2. *Station Circuit Breakers*

Input Data Supporting the Circuit Breaker AA Framework

Similar to Power Transformers, the Asset Analytics formulation for Station Circuit Breakers leverages all six evaluation categories (i.e. Demographics, Condition, Performance, Utilization, Economics, Criticality) in order to produce an overall composite risk score. The average data availability score across all individual input variables supporting the evaluation category scores is approximately 90%.

Figure 10 illustrates the average sample sizes across the inputs for each evaluation category[3].

[3] The overall data availability scores referenced above were calculated on the basis of an average across all individual input values in all categories – not across the averages of each individual category presented in the tables below. Individual input data availability also takes into consideration the relevance of the particular input parameter for evaluating the specified circuit breaker type.

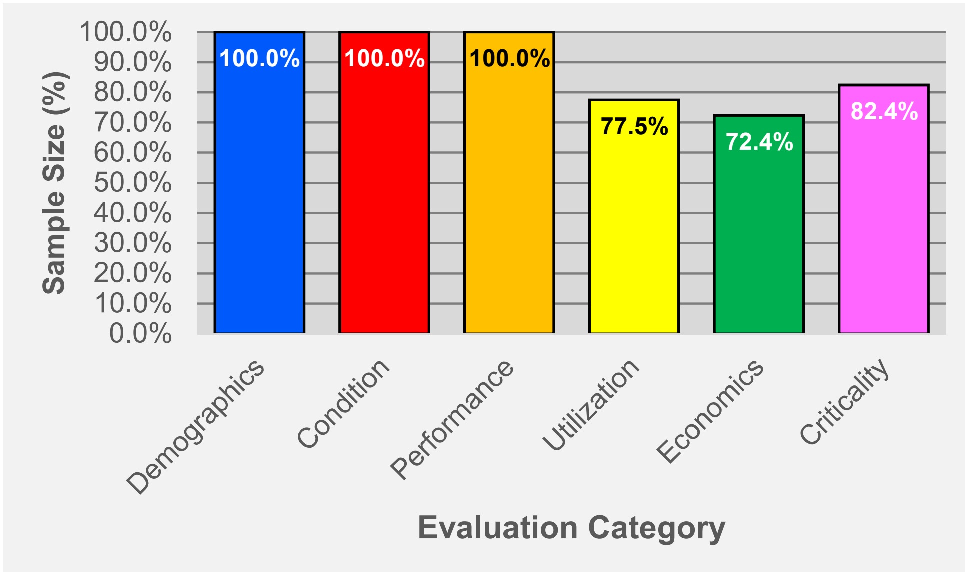


Figure 10. Station Circuit Breaker Average Sample Sizes for Each Evaluation Category

Overall, METSCO found the data availability scores for this asset class to be robust, and reasonable to make meaningful calculations across each of the categories. Moreover, METSCO notes the very high Condition, Utilization, Performance, and Criticality data availability scores.

Similar to the Station Power Transformers we recommend that HONI continues mitigating its data gaps as part of continual improvements, such that the sample sizes of evaluation categories (and overall sample size within AA) can improve over time. It should be noted, however, that all circuit breaker assets ultimately receive an evaluation category score as well as an overall composite risk score through the use of the data completeness procedure as discussed in Section 2.1.

Circuit Breaker AA Evaluation Score Criteria & Results

As is the case with power transformers, circuit breaker assets utilize the same six evaluation category scores containing references to "risk-based" calculations, in which these variables refer to either the probability or impact of asset failure. The underlying criteria for Demographics, Performance, Economics and Criticality categories are similar to the power transformers calculation as explained in Section 3.2.1, with the exception of the following incremental data points:

- Performance: Historical trouble call and defect report notifications support circuit breaker evaluation in instances where historical outage data is unavailable.

- Economics: The average work order cost is applied within this category in addition to the criteria. For air-blast circuit breakers, the average operational count of the breaker is also utilized as part of the calculation.

- Criticality: Considers the voltage rating of the breaker as well as the breaker position.

Moreover, criteria used for Utilization and Condition evaluation categories are unique to circuit breaker asset class. For Utilization, inputs that reflect the overall usage of the breaker include:

- Breaker counter readings;
- Maximum number of operations prior to reaching the end of life (EOL)[4] threshold;
- Total number of breaker operations;
- Functional location of the breaker: (whether is it a capacitor- or a reactor-positioned breaker), the interrupting rating (in kA) of the breaker at the system level, and equipment level respectively; and
- The fault adjusted operation (FAO) of the breaker (used to predict and perform breaker maintenance based upon accumulated fault duty).

The evaluation criteria within the Condition category, predictably vary with the functional type of breaker. All condition formulas for circuit breakers include:

- Annual number of defect reports and trouble calls;
- The notification benchmark, which represents the 5-year average of all annualized defects by nominal voltage;
- Number of preventative reports used for reporting findings from maintenance inspections; and
- The year when a circuit breaker has been rebuilt (if relevant).

Oil-filled circuit breakers contain additional consideration of oil top-up operations performed in a year, while SF_6-insulated breakers contain an evaluation of SF_6 top-up operations.

[4] End of Life is defined by HONI as "the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences." [2]

As is the case for power transformers, it is METSCO's recommendation that HONI consider integrating of more commonly used variables for risk-based calculations, such as failure probability curves coupled with the impact of failure. Specific to circuit breakers, we also recommend that HONI consider integrating additional parameters that it currently collects through maintenance and inspection activities and considers as a part of the ARA analysis directly into the AA framework. These include:

- Oil leaks, gasket and seal condition (oil-filled circuit breakers);
- Tank integrity and mechanism box condition (oil / SF_6);
- Condition of air system (air-blast circuit breakers);
- Air consumption test (air-blast circuit breakers);
- Tripping and closing resistors (air-blast circuit breakers);
- SF_6 gas analysis (SF_6-insulated circuit breakers).

It is also notable that certain inspection parameters are considered as part of the condition scoring but are integrated within other categories rather than being individually scored and weighted. As an example, the condition category contains a scoring parameter that relates to "work packages", which contains underlying inputs such as timing/travel and contact resistance tests respectively. The condition category also contains a scoring parameter relating to historical defect report notifications, which often contain underlying inputs such as bushing/support insulator inspection results and infrared scanning results. As part of continual improvements, HONI can consider breaking out these parameters in order to introduce a more transparent calculation.

When examining the "highest risk" circuit breakers as prioritized through the composite risk score result, METSCO found that the composite results agreed with the underlying inputs. As an example, the highest risk circuit breaker on the list was found to be in very poor condition and had experienced multiple trouble call /defect report notifications, sustaining corrective and emergency repair costs in the past five years.

Similar findings concern the 20 highest priority (in terms of AA risk) circuit breakers – all of which were found to possess a condition score result equivalent to a poor or very poor finding, and had encountered some form of performance-related issues (either in the form of trouble calls/defect reports or actual outages) and many of which were found to be approaching or already exceeding their ESL criteria.

Circuit Breaker ARA Components

As part of the ARA process, HONI supplements the AA-generated scores with a range of additional data inputs. The combination of these factors informs the utility's circuit breaker strategy and technical assessment documents, which underlie its long- and short-term decisions for a given asset class, respectively. METSCO examined these documents and discussed their content with HONI SMEs, as a means of establishing the scope and nature of additional information comprising the ARA review.

METSCO found HONI's circuit strategy document to further supplement the AA framework results with incremental analysis conducted for each of the six evaluation categories assessed during the ARA process. Key additional parameters include:

- Demographics: Demonstrating the current and future replacement needs through the evaluation of circuit breakers (including sub-types) that are currently beyond their expected service life.

- Condition: Discussion of the degradation issues concerning circuit breaker assets, including state of the breaker contacts, O-rings and control components.

- Performance: Assessment of historical reliability events, including forced outages by cause, and comparison of forced outage rates by breaker sub-type, as well as resulting reliability impacts on the system supply points.

- Economics: Discussion of OM&A costs for each group of breakers at each substation, along with specific spending requirements associated with breaker sub-types (e.g. ongoing spending for high-pressure air system infrastructure supporting the legacy air-blast circuit breakers to be replaced).

Figure 11 and Figure 12 illustrate examples of the types of incremental information captured from HONI's strategy document and examined as a part of ARA - in this case, the circuit breaker demographics and performance respectively. Figure 11 illustrates the quantity of breakers that are past their ESL criteria, providing an indication of the volume of breakers that may require replacements in later years. Figure 12 presents the historical reliability of different breaker types over the past 10-year period. HONI uses these results to further explore the need to prioritize the replacement of the air-blast circuit breakers over other types.

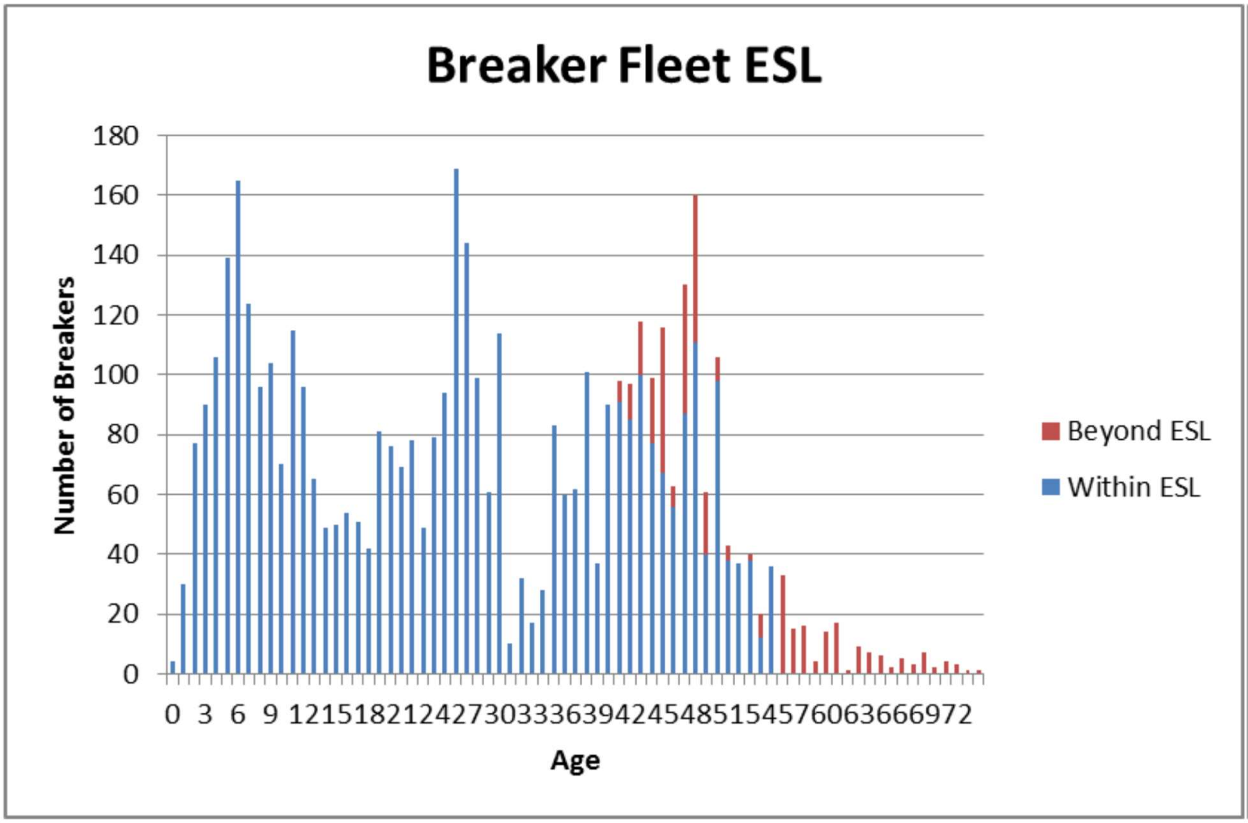


Figure 11. Station Circuit Breaker Demographics [5]

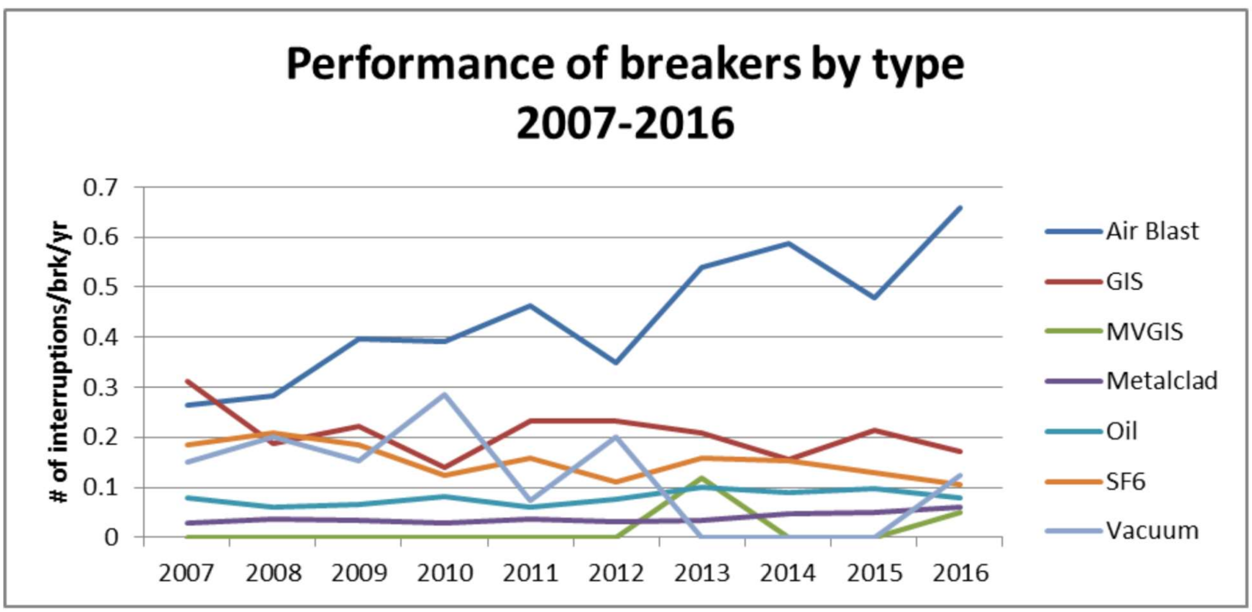


Figure 12. Performance of Circuit Breakers by Type [5]

The document also includes additional risk factors as identified within the ARA process to further justify circuit breaker replacements, including obsolescence (e.g. availability of parts) and safety (e.g. safety risks associated with failure modes for specific circuit breaker sub-types). Throughout this document, HONI articulates the processes undertaken in order to capture this input data (e.g. process for condition assessment) and also explains the consequences if no actions are taken.

Key outputs produced on the basis of the strategy document include the recommended investment and maintenance strategies, respectively.

Overall, through the assessment of circuit breaker analysis parmeter, METSCO identified that HONI's decision-making does not simply rely upon the AA results, but moves beyond these results into the detailed incremental analysis that serves to further support the final decision regarding the need for a particular intervention type. Further examination of the input data supplied into AA into the strategy documents serve to validate the AA framework and results.

As is the case with power transformers, opportunities for incremental improvements to the ARA procedure for circuit breakers would include further integration of the incremental analysis within the AA framework directly.

3.2.3. Stations Ancillary Equipment (DC Batteries & Chargers)

Input Data Supporting the Stations Ancillary AA Framework

Asset Analytics formulation for DC batteries and chargers leverages five out of the six evaluation categories that are relevant for analysis, including Demographics, Condition, Performance, Economics and Criticality, in order to produce an overall composite risk score. The average availability score across all input variables supporting the station battery evaluation categories is just over 90%, while the average availability score supporting the battery charger evaluation categories is just under 90%..

Figure 13 and Figure 14 illustrate the average sample sizes across the inputs for each evaluation category for DC battery and charger assets respectively. These results illustrate an extensive sample size of data that has been captured to support these assets[5].

[5] The overall data availability scores referenced above were calculated on the basis of an average across all individual input values in all categories - not across the averages of each individual category presented in the tables below.

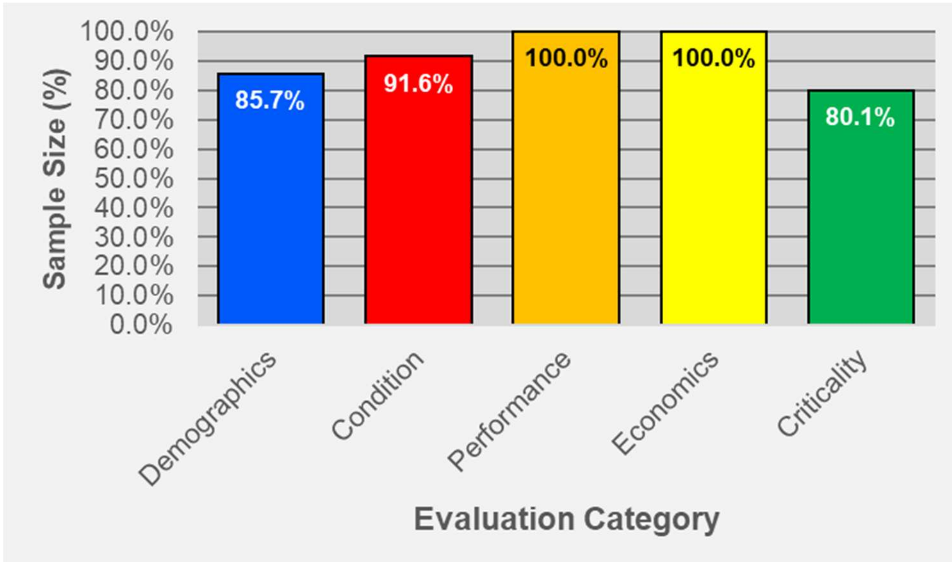


Figure 13. DC Battery Average Sample Sizes for each Evaluation Category

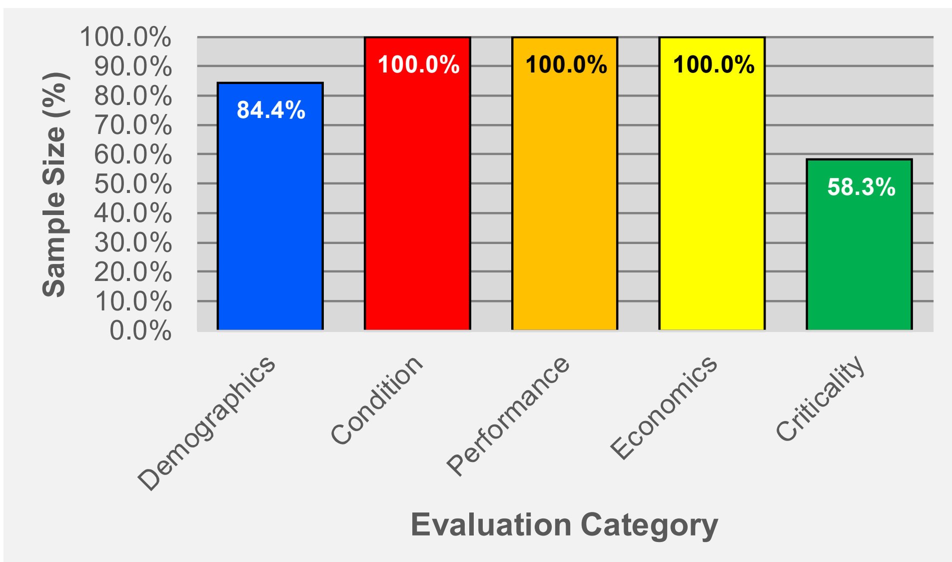


Figure 14. Charger Average Sample Sizes for each Evaluation Category

Overall, METSCO found the data availability scores for this asset class to be reasonable to make meaningful calculations across each of the categories. While the score for Criticality for chargers constitutes a relative outlier relative to other categories, we note the perfect scores for Condition and Performance, as especially relevant for this asset class.

We recommend that HONI continue mitigating the identified data gaps as part of continuous improvements, such that the sample sizes of evaluation categories (and overall sample size within AA) can continue to improve over time.

Stations Ancillary AA Evaluation Score Criteria & Results

As is the case with power transformers and circuit breakers, the evaluation category scores for stations ancillary assets contain references to "risk-based" calculations, in which these variables refer to either the probability or impact of asset failure (both being inputs of a comprehensive definition of risk as per industry best practices). The underlying criteria for Demographics, Performance, Economics and Criticality categories are similar to the power transformers calculation as explained in Section 3.2.1, with the exception of the following exceptions / incremental additions:

- Performance: Uses historical trouble call and defect report notifications (similar to circuit breakers);
- Criticality: Uses the same criteria with the exception of the single point of vulnerability.

Condition evaluation criteria used for evaluation of DC battery assets include:

- Overall physical condition (i.e. leaking, tracking, cracks, condition of seals, corrosion, etc.);
- Discharge testing results – 30 min AC (i.e. time to discharge);
- Final discharge voltage – 30 min AC and 2-hour load test;
- 2-hour Battery Load test;
- Average voltage;
- Battery float current;
- Number of cells;
- H20 added (flooded cells only);
- Specific gravity (SG) (flooded cells only).

We see the above list of DC battery degradation factors that HONI considers as being very comprehensive.

For charger assets, a single overall condition rating is currently assigned, although HONI plans to further expand this rating into individually weighted degradation factors, as we established in the course of our interviews. As is the case for power transformers and circuit breakers, it is METSCO's recommendation that HONI consider the integration of more commonly understood variables for risk-based calculations, such as failure probability curves coupled with the impact of failure.

When examining the DC battery and charger assets considered to be individual highest risk assets on the basis of AA assessment, we found that the composite results aligned with the data contained within the underlying inputs. The highest prioritized DC battery and charger assets were both found to be past their ESL criteria and had encountered a number of performance issues. Our assessment of the 20 highest-rated (in terms of AA risk) station ancillary equipment units yielded similar findings regarding consistency of the final scores and the individual factors considered in the analysis.

Stations Ancillary Equipment ARA Components

Our examination of HONI's DC battery and charger strategy document, which captures the data generated and considered as a part of the ARA process, confirmed that the utility considers a number of additional factors that supplement, enhance and help validate the quantitative insights captured in the AA analysis, including the following information grouped according to the major risk assessment factors:

- Demographics: Demonstrating the current and future replacement needs through the evaluation of station batteries and chargers that are currently beyond their expected service life.

- Condition: Discussion of degradation issues concerning the DC system assets, including material flaws within the battery container, lead contamination, plate connection weld failures, electrolyte contamination, failure of the terminal post seal, improper charging, and others.

- Criticality: Review of criticality criteria associated with the DC battery & charger assets, including ampere rating, voltage rating and station location, with the corresponding implications for the overall criticality level.

Figure 15 illustrates an example of the incremental analysis performed with respect to the criticality of the stations ancillary asset population. These results are used by HONI to further justify the prioritization approach for these assets as part of a long-term plan.

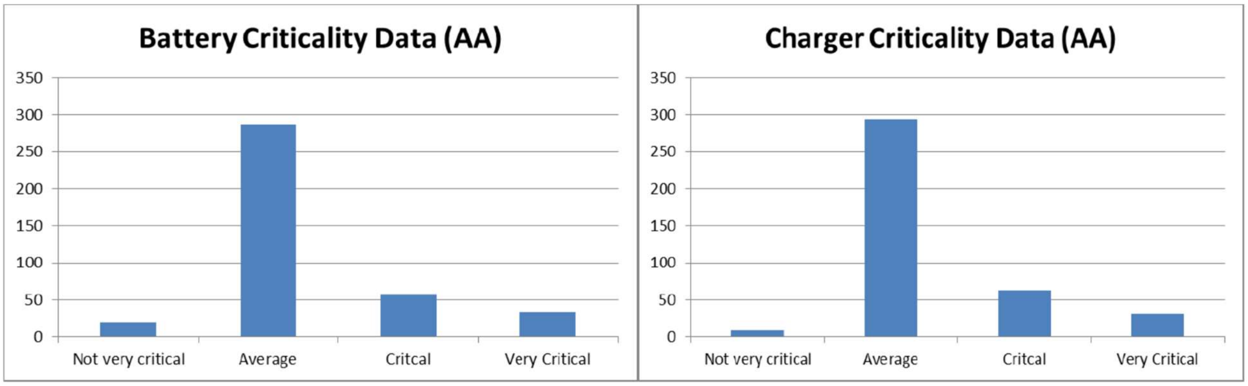


Figure 15. Overall Criticality of the Stations Ancillary Asset Fleet

The document also includes additional risk factors as identified within the ARA process to further justify stations ancillary asset replacements, including safety (e.g. the explosive nature of the "VRLA-type" batteries, which are being replaced with standardized "VLA" batteries).

For individual battery replacements, HONI performs targeted asset assessments beyond the strategy document and produces an NPV calculation. This evaluation considers various intervention options, including refurbishment, repair and replacement of the battery population. The underlying calculation methodology is similar to the NPV calculation performed for power transformers discussed above.

Key outputs produced as per the strategy document include recommended OM&A strategies, including preventative maintenance and corrective maintenance actions, along with a long-term implementation plan for the future replacement of assets.

Through the adoption of the ARA procedure, HONI's decision-making process for stations ancillary assets moves beyond the AA results, taking into consideration detailed additional factors that serve to further justify the final decision-making strategies. As with other asset classes, we see this multi-stage process to be comprehensive and reflective of a large number of diverse performance issues that cover all major categories.

Opportunities for continuous improvement include further integration of the incremental analysis occurring within the ARA framework directly into the AA analysis. As with other assets, we also recommended that the NPV analysis performed for individual station ancillary asset assessments should consider socio-economic factors in addition to financial costs, including collateral damages, environmental and customer interruption cost impacts, in an effort to consider the total economic costs associated with equipment failures.

3.2.4. Line Conductors

Input Data Supporting the Line Conductor AA Framework

The Asset Analytics formulation for Line Conductors leverages five out of the six evaluation categories relevant for Line Conductor analysis, including Demographics, Condition, Performance, Utilization and Criticality, in order to produce an overall composite risk score. The average sample size across all input variables supporting the evaluation category scores is just under 85%. Figure 16 illustrates the average sample sizes across the inputs for each evaluation category[6].

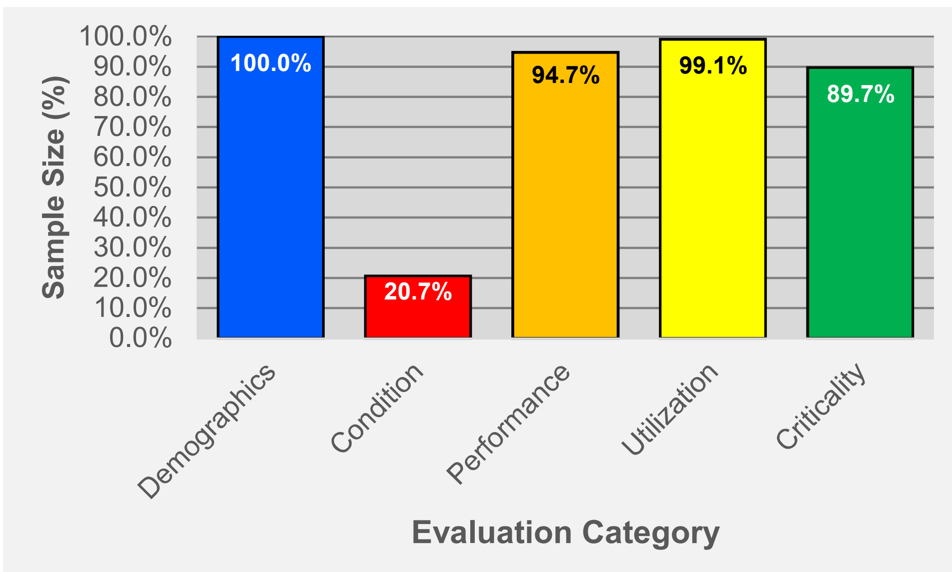


Figure 16. Line Conductor Average Sample Sizes for each Evaluation Category

Standing out from these results is the apparently low availability score for conductor Condition in particular. However, as we had learned from subsequent discussions with Hydro One, this score is largely reflective of the utility's strategy with respect to conductor condition collection, the methodology of carrying out the testing, and the manner of reflection within the underlying databases. As a matter of policy grounded in past experience, Hydro One does not collect condition data for any overhead conductors younger that 50 years, assuming that they all remain in good condition or better. Similarly, when testing cables using the new LineVue technology, or conducting laboratory tests on the basis of spliced conductors, Hydro One tests only one of the

[6] The overall data availability scores referenced above were calculated on the basis of an average across all individual input values in all categories - not across the averages of each individual category presented in the tables below. Individual input data availability also takes into consideration the relevance of the particular input parameter for evaluating the specified conductor type.

circuits on a given line and only select conductor spans. Hydro One then assumes that the condition score calculated on a given circuit and spans also applies to the adjacent circuit and spans. While the calculation algorithm makes this assumption, (which METSCO sees as reasonable), HONI data tables that METSCO examined do not clearly reflect this. Accordingly, the effective Condition data availability for overhead conductors in light of Hydro One's policies and practical testing approaches is significantly higher than what an initial review of data would indicate.

METSCO sees this prioritized approach where condition is not collected for younger vintages or adjacent circuits and spans, as a positive example of pacing and managing its data collection efforts. In other words, HONI's efforts to acquire conductor condition information within the operating and budgetary constraints are grounded in sensible managerial assumptions regarding the assets in close proximity to the ones undergoing diagnostic testing.

As with other instances of data gaps, we recommend that Hydro One continue its ongoing work to rectify the remaining gaps using the approach is already in place.

Line Conductor AA Evaluation Score Criteria & Results

Consistent with other asset classes examined, each of the evaluation category scores for line conductors contains elements that indicate probability or impact of asset failures – the two components that make up the best-practices definition of asset risk. Calculation of the demographics evaluation score is performed using the same underlying criteria as described for power transformers in Section 3.2.1, with the exception of ESL criteria that are specific to line conductor.

The Performance evaluation score takes into consideration granular historical reliability event data, including:

- quantity of total outages sustained;
- date of the most recent outage event;
- mean operating time before failures (MTBF);
- outage frequency and duration.

The Utilization evaluation score considers the summer continuous planning rating of the conductor, along with the total hours where the conductor loading was found to be in the range of 90%-110% of the rating, and the total hours where the conductor loading exceeded 110% of the rating.

The Criticality evaluation score accounts for the configuration of the line conductor, including:

- Whether the conductor provides supply to generation sources;
- If the conductor represents an interconnection;
- If the conductor is a Radial or Network asset;
- Total customer load on the conductor and;
- Customer supply, and critical customers connected to the conductor.

Finally, the Condition evaluation category score (where available) for line conductor considers the following criteria:

- Extent of rust on conductor span;
- Severity of rust on conductor span;
- Remaining zinc (%);
- Torsional ductility (expressed as number of turns)
- Tensile strength of the conductor (%)

We see HONI's condition evaluation score as fairly comprehensive - given the number of advanced tests that it performs. METSCO recommends that as HONI makes progress to supplement its condition score database related to conductors, it also consider collecting information associated with accessories including sleeves, spacers, dampers and armor rods.

When examining the individual and top 20 "highest risk" conductors as prioritized through the composite risk score result, we observed that the composite results followed logically from the values of the underlying inputs, yielding actionable insights. Importantly, those conductors where condition data was available were found to be in very poor condition. METSCO sees this as both validation of Hydro One's prioritization efforts of selecting the areas to undertake the extensive condition tests, but also a potential indication of a larger trend that we advise HONI to continuously monitor as it accumulates more new testing results.

Line Conductor ARA Components

As part of the ARA process, HONI will derive line conductor strategy documents on the basis of additional information considered in the course of the ARA process including the following:

- Demographics: assessing the current and future replacement needs through the evaluation of line conductor that are currently beyond their expected service life.

- Performance: consideration of historical reliability events, including outage frequency and duration over the past 10-year period.

- Condition: Discussion of the highest-risk assets on the basis of their condition evaluation category results.

The conductor strategy document includes assessments on obsolescent conductor spans that are reaching their ESL criteria. These particular conductors are either obsolete (e.g. use materials no longer used in conductor manufacturing or have alternatives that perform significantly better in the particular conditions), or have reached end of life on the basis of condition assessments.

Figure 17 and Figure 18 respectively illustrate an example of incremental ARA analysis captured in the line conductor strategy document. In this case, the growing backlog of conductors past ESL (as illustrated in Figure 17) over the next 10 years is compared to the proposed rate of replacement when taking into consideration available resourcing and system constraints (as illustrated in Figure 18).

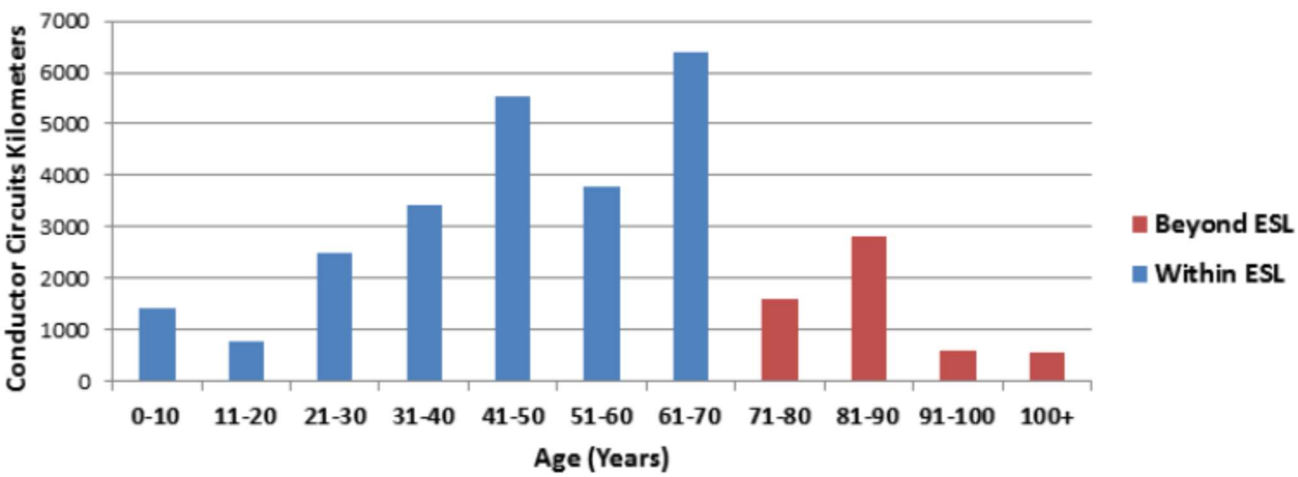


Figure 17. Conductor Demographics and Amounts past ESL Criteria

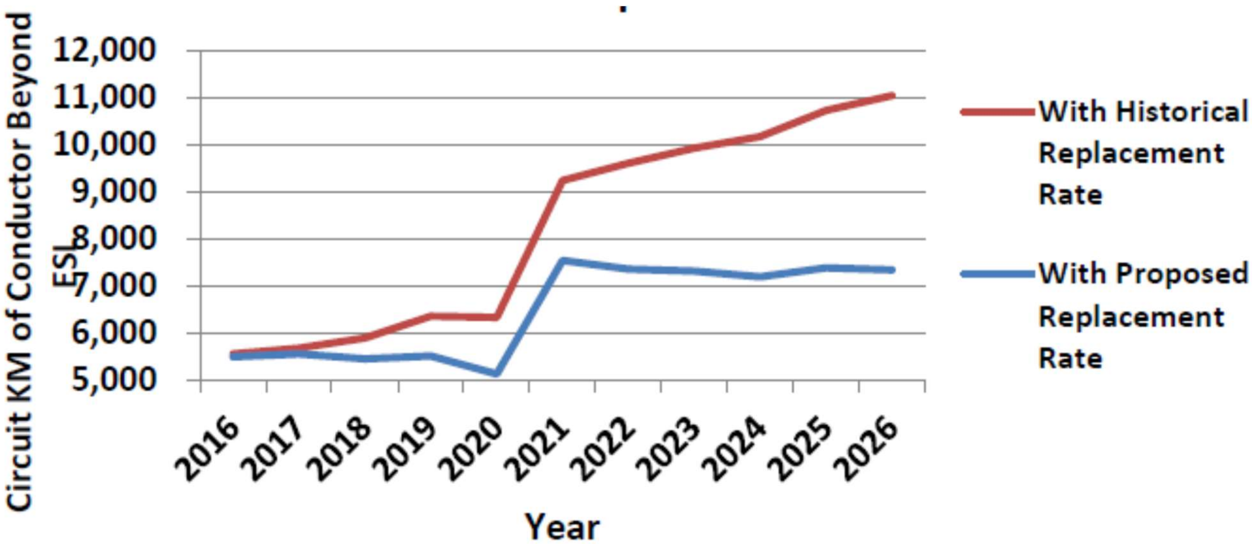


Figure 18. Comparison between Backlog and Proposed Replacement Rate

We also note that HONI continues to continually improve the underlying evaluation inputs used for the ARA procedure. An example of this is in regards to the ESL rating of line conductor, where the 70-year life span (applied in Figure 17) was recently changed to 90 years, following further research and analysis conducted by HONI experts. As part of future continual improvements, HONI will be updating their AA algorithm to account for this improvement. METSCO sees this enhancement driven by practical field insights as a notable example of capital replacement work pacing.

Importantly, in addition to the condition results as provided within AA, HONI also leverages laboratory testing in order to perform an in-depth assessment of the conductor with respect to its tensile strength, measured breaking strength and de-rated measured breaking strength. The results of this incremental analysis is utilized as part of the ARA process in order to further prioritize line conductors for intervention.

METSCO understands that HONI was recently acknowledged as one of the most progressive transmission utilities as part of an EPRI industry survey of conductor inspection practices. This conclusion was reached based upon HONI's utilization of field surveys in combination with laboratory validation technology, such as the LineVue technology and the remaining strength testing discussed above [6].

HONI's relatively recent adoption of the incremental tests comprising the ARA procedure for line conductor and the 20-year extension of the expected service life for conductors, demonstrates that asset managers are going beyond the AA results and existing assumptions, taking into consideration detailed incremental analysis and testing results in order to evaluate their final decision-making strategies and prolong the service life of its plant.

As with other asset types, while we see some merit in integrating the tests comprising the ARA more directly into the AA analysis, we recommend that such steps be considered only in the context of significant procedural reorganization of the asset management process/analytics capabilities, should they be contemplated. Absent such an initiative in the coming years, we the presence of sequential incorporation of additional criteria within the overall AM framework as sufficient, and in some ways may be seen as preferable to full integration into a single index, as the current sequencing foster a sequential multi-stage validation process. One potential context in which such integration could be justified in particular is if it is seen as a source of material administrative and/or operational efficiencies.

3.2.5. Underground Cables

Input Data Supporting the Underground Cable AA Framework

The Asset Analytics comprehensive index formulation for Underground Cable leverages five out of the six evaluation categories relevant for Underground Cable analysis, including Demographics, Condition, Performance, Utilization and Criticality, in order to produce an overall composite risk score. We calculated the average data availability across all input variables supporting the evaluation category scores to be just over 90%[7].

Figure 19 illustrates the average sample sizes across the inputs for each evaluation category.

[7] The overall data availability scores referenced above were calculated on the basis of an average across all individual input values in all categories – not across the averages of each individual category presented in the tables below. Individual input data availability also takes into consideration the relevance of the particular input parameter for evaluating the specified cable type.

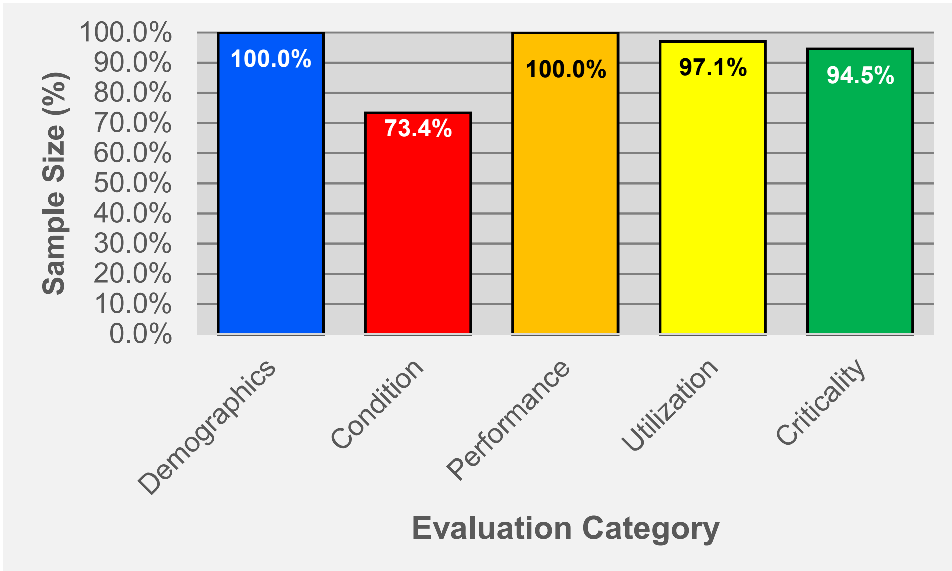


Figure 19. Underground Cable Average Sample Sizes for each Evaluation Category

In general, the results in Figure 19 illustrate a mostly complete and robust set of data being utilized for the purposes of underground cable evaluation. From these results, the condition category generates the lowest sample size. However, much of this of driven by the very low availability of a single parameter used in the condition calculation pertaining to Insulation Condition. Results for this parameter are determined from a destructive test that is only performed on paper-insulated cables under rare cases where a repair is performed. As the test is seldom performed, HONI may want to consider removing this parameter in favor of other testing results that are more commonly performed across the cable population. At present, however, METSCO endorses an approach where the condition parameter score requiring destructive testing is only collected when failures mandate destructive repairs.

In making the above observations, with respect to this and other asset classes where data gaps exist, we are cognizant of the reality that the number of potential areas where enhancements can be made substantially exceeds the financial and human resources available to complete these enhancements. Accordingly, our observations regarding the recommended enhancements reflect the expectation that HONI proceed to implement them upon a prioritization process across the process components, asset classes, etc. Expecting the balance of these gaps to be closed within a short period of time (e.g. a single five-year rate cycle) would be both unrealistic and imprudent.

Underground Cable AA Evaluation Score Criteria & Results

As is the case with line conductors, underground cable assets utilize the same five evaluation category scores containing factors related to probability and impact of asset failure. The underlying criteria for Demographics, Criticality and Utilization categories are similar to those used for line conductor calculation as explained in Section 3.2.4, using ESL rates applicable to cable demographic analysis.

Criteria used for performance and condition evaluation categories are unique to underground cable asset class. For Performance, inputs reflect historical reliability of a given cable segment, including:

- Number of historical cable faults;
- Other cable failures as recorded;
- Quantity of outages.

The evaluation criteria within the Condition category include:

- Oil testing results;
- Insulation condition;
- Accessory condition;
- Installation conditions;
- Corrosion protection condition; and
- Jacket voltage condition.

While METSCO sees HONI's current Condition evaluation criteria for transmission cables as substantially comprehensive, we recommend that Hydro One consider the thermography scanning of terminations and splices directly within the Condition scoring as part of continuous improvements (note that thermography scanning is performed and considered, but as part of the broader ARA process).

Our insights from examining the results of AA prioritization (the top segment and the 19 segments that followed in terms of the overall composite risk score) were consistent with those for other asset classes. The relative nature and magnitude of contributions from individual sub-indices and their components were indicative of a cable segment that warranted further investigation, if not outright replacement.

Underground Cable ARA Components

Consistent with other asset classes examined, HONI's ARA process provides the testing and analytical grounds for the content of the underground cable strategy documentation that drives long-term decision-making related to this asset class. Beyond the AA data, these strategy documents further supplement the results from the AA framework drawing from incremental analysis conducted for each of the evaluation categories, including:

- Demographics: replacement rate scenario comparisons as with other asset classes examined.

- Performance: comprehensive historical reliability event analysis where data is available in sufficient quantities.

- Condition: Discussion of thermography process and its results, which is currently executed in the context of the ARA work.

- Criticality: Discussion of cables of greatest criticality, including those in densely populated urban locations, servicing largest loads, and cables used to connect large load customers, such as local distribution companies (LDCs).

- Utilization: Discussion of load forecasts for large urban centers, such as the City of Toronto, along with the key results of the regional planning studies that plan to resolve these risks into the future.

Other factors considered in the course of ARA work and informing the asset strategy include obsolescence (e.g. challenges associated with obsolete LFPF and HPLF cables), safety (e.g. heightened risks associated with LFPF and XLPE joints in vaults and tunnels due to explosive failure modes) and environment (e.g. potential for oil leaks associated with LFPF and HPLF cable types).

Figure 20 and Figure 21 respectively illustrate an example of the historical reliability incremental analysis that is performed within the strategy document, in the form of cable outage frequency and duration respectively.

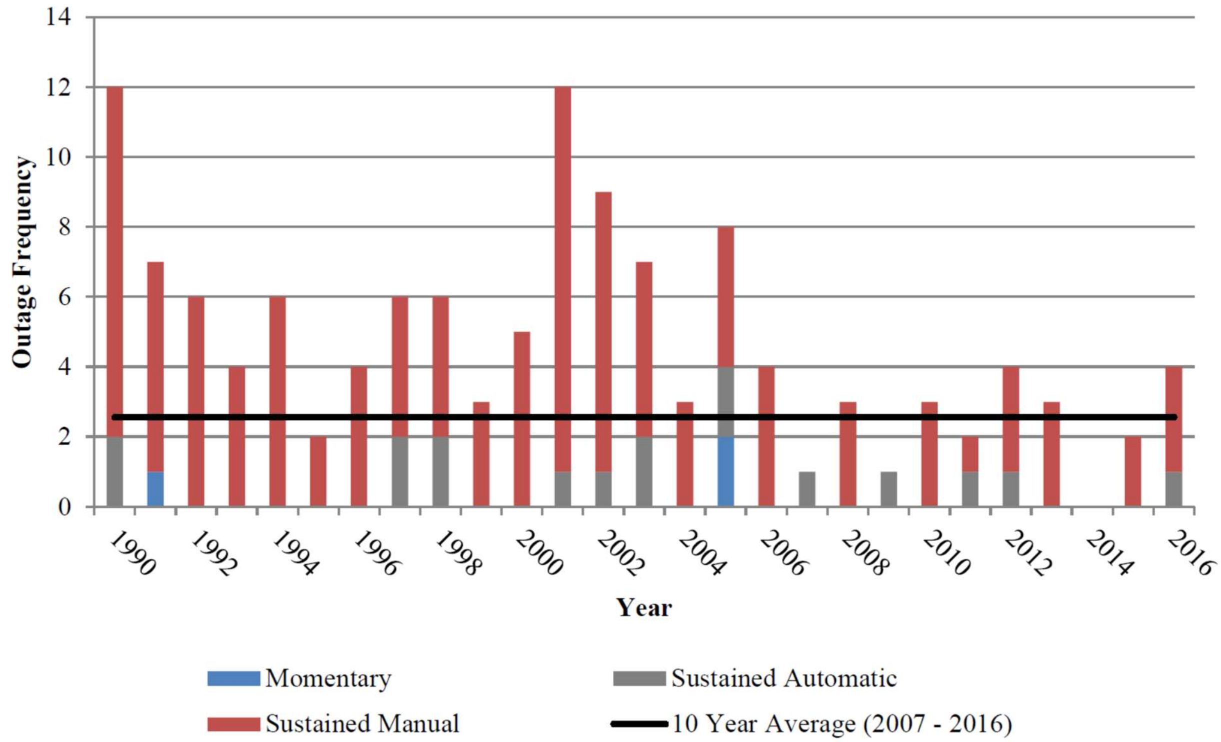


Figure 20. Underground Cable Outage Frequency

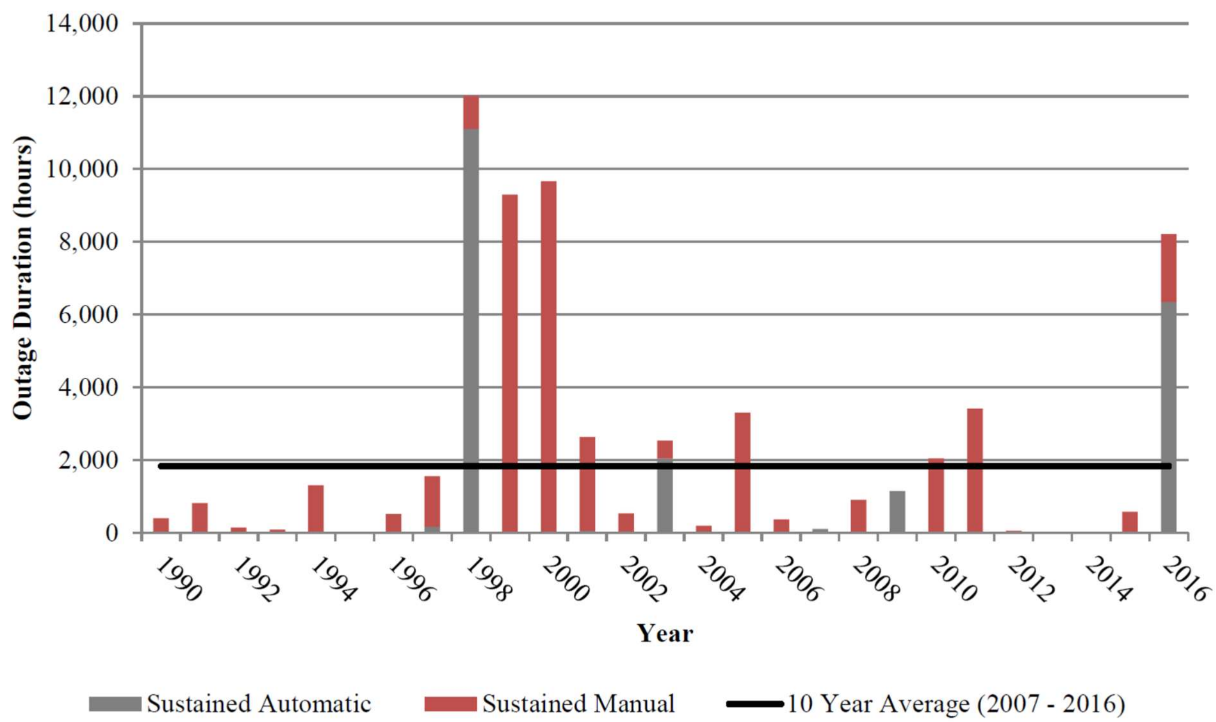


Figure 21. Underground Cable Outage Duration

Key outputs produced as per the strategy document include the long-term implementation plan associated with high-priority cables reaching their ESL based on the AA and incremental analysis results. As is the case with other assets, HONI continues to continually improve the underlying evaluation inputs used for the ARA procedure. An example of this is a recent extension of the ESL threshold for underground cable from 50 years to 70 years for HPLF and LPLF cable types. HONI has worked with third-party research entities such as the Electric Research Power Institute (EPRI) in order to define the ESL ratings for underground cables. As with our observations regarding the extension of overhead conductor ESL assumptions, we note this as a practical example of HONI's efforts to manage the pace of its capital replacements, grounded in incremental analytical insights.

As was the case with line conductor, HONI's utilization of the ARA procedure for underground cables demonstrates an approach that extends beyond the automatically generated AA results, taking into consideration incremental analysis in order to justify the final decision-making strategies, and applying balanced judgment across a number of input criteria (the insights of which can, at times, be conflicting).

3.2.6. Protection & Control (P&C) and Automation Equipment

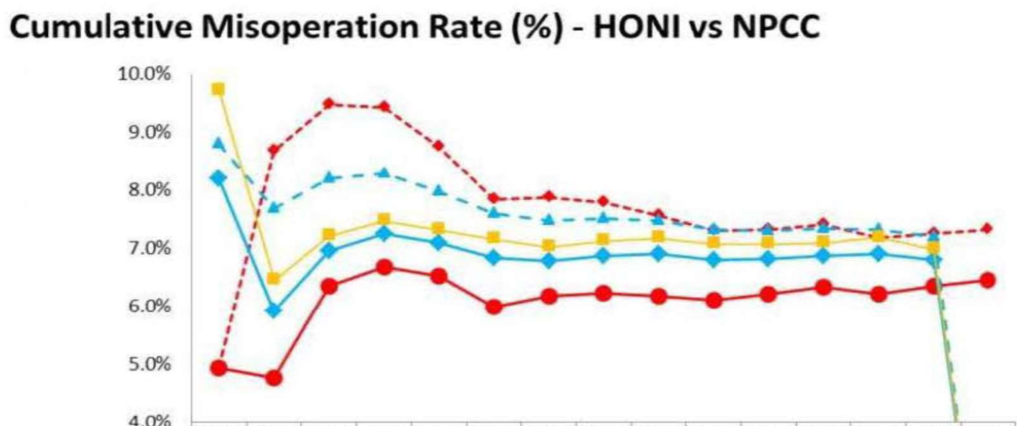
With respect to protection & control and automation-related assets, Hydro One's asset analysis is mostly centered on technological obsolescence, as a function of interoperability, parts availability and equipment support, and regulatory requirements, among others. . Among other factors, interoperability is particularly critical for protection and communication equipment, to ensure that the assets respond appropriately and reliably during a contingency.

In METSCO's experience, Hydro One's approach to P&C and Telecom asset management is consistent with those used by other transmitters. However, we encourage Hydro One to explore incorporation of other asset management decision-making drivers into the scope of a formalized IT capability-based analytics tool, subject to feasibility and value for money analysis. As we have learned by way of SME interviews, a number of such activities do take place periodically, albeit they are largely manual in nature. These activities include:

- Internal stakeholdering to ensure alignment with other ongoing projects;
- Standards compliance monitoring to mitigate obsolescence issues;
- Examination of historical performance data (e.g. mis-operations);
- Field visits for specific data collection;

- Short-circuit analysis, relay coordination, telecom propagation and terrain radio signal penetration studies;
- Development of replacement project specification standards;
- Peer review and validation of chosen specifications.

In the manner consistent with the ARA process, Hydro One uses these insights to produce a strategy document that informs the long-term replacement approach. Figure 22 illustrates an example of such expanded analysis performed in support of strategy development. In this case, the analysis demonstrates that HONI's performance is very good with respect to mis-operations over the past three-year period.



	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1	2016 Q2	2016 Q3	2016 Q4
HONI Cumulative Misop Rate	5.0%	8.7%	9.5%	9.4%	8.8%	7.8%	7.9%	7.8%	7.6%	7.3%	7.3%	7.4%	7.2%	7.3%	7.3%
HONI Cumulative Misop Rate (disregarding 2013 Flood)	5.0%	4.8%	6.4%	6.7%	6.5%	6.0%	6.2%	6.2%	6.2%	6.1%	6.2%	6.3%	6.2%	6.4%	6.5%
NPCC - Overall	8.8%	7.7%	8.2%	8.3%	8.0%	7.6%	7.5%	7.5%	7.5%	7.3%	7.3%	7.3%	7.3%	7.2%	0.00%
NPCC - Overall disregarding 2013 Flood	8.2%	5.9%	7.0%	7.3%	7.1%	6.8%	6.8%	6.9%	6.9%	6.8%	6.8%	6.9%	6.9%	6.8%	0.0%
Other NPCC members	9.7%	6.5%	7.2%	7.5%	7.3%	7.2%	7.0%	7.1%	7.2%	7.1%	7.1%	7.1%	7.2%	7.0%	0.0%

Figure 22. Historical Mis-operation Rate for HONI Infrastructure

Opportunities for continual improvements would include the further integration of the current manual planning process into existing enterprise systems, such that productivity improvements can be realized.

3.3. Level 3 Assessment: Practical Implementation Issues

As the final layer of METSCO's combined review of the AA and ARA capabilities, we sought to examine how HONI deploys them in a practical setting, on the basis of specific case studies representative of normal operating practices and using real equipment data. In doing so, we sought to ascertain whether and how the preliminary insights through the AA assessment are ultimately supported, verified, debunked and/or otherwise enhanced through the analysis comprising the broader ARA process.

From the sequencing perspective, METSCO suggested to Hydro One to conduct this analysis at the very conclusion of the interview-based and data review engagements that informed our Levels One and Two review. We did so for three reasons:

1. To ensure that specific practical examples do not interfere with our review on the process /asset class level;

2. To explore the manner in which the (largely) algorithm-driven AA calculations are assessed against the ARA insights that incorporate a greater degree of qualitative / strategic considerations; and

3. To validate our understanding of sequencing and iteration that typically occurs in the course of Hydro One's asset management procedures.

To conduct this final stage of our assessment, METSCO asked Hydro One SMEs to provide us with case studies representative of three hypothetical scenarios associated with stations and line conductor replacement (one each):

a) Investment scenarios where the preliminary AA results aligned with the results of the subsequent ARA process to select and validate an immediate short-term investment candidate;

b) Investment scenarios where the results of the broader ARA process contradicted those of the preceding AA assessment, thereby stopping the immediate consideration of an investment candidate suggested by AA; and

c) Investment scenarios where a short-term investment candidate was identified through the incremental information identified through the ARA process, but was not sufficiently supported on the basis of the AA framework alone.

We provide the descriptions of the mini-case studies supplied by Hydro One following brief recaps of the overall evaluation methodology sequencing for stations and overhead conductors, respectively. As noted earlier, we provide the examples of particular real-life projects solely for the purposes of illustrating the nature and sequencing of the associated processes – not justification of any findings relating to a given project. As such, we have substituted the specific asset identifiers with generic one (e.g. "ABC TS") to keep the focus on process, rather than particular assets.

3.3.1. Stations Evaluation

As per the ARA procedure, Hydro One station assets, (power transformers, circuit breakers and ancillary equipment) are replaced as a group – typically at a station level. By performing renewal of an entire substation and associated equipment at once, HONI seeks to realize operational savings relating to work scheduling and outage coordination, among other sources of benefits.

Results from AA analysis serve as a starting point for the evaluation. Composite risk score results are used in conjunction with the underlying individual AA sub-indices. A station assessment is subsequently performed in which a series of inputs are utilized in addition to AA in order to provide incremental decision support. These inputs are further illustrated in Figure 23.

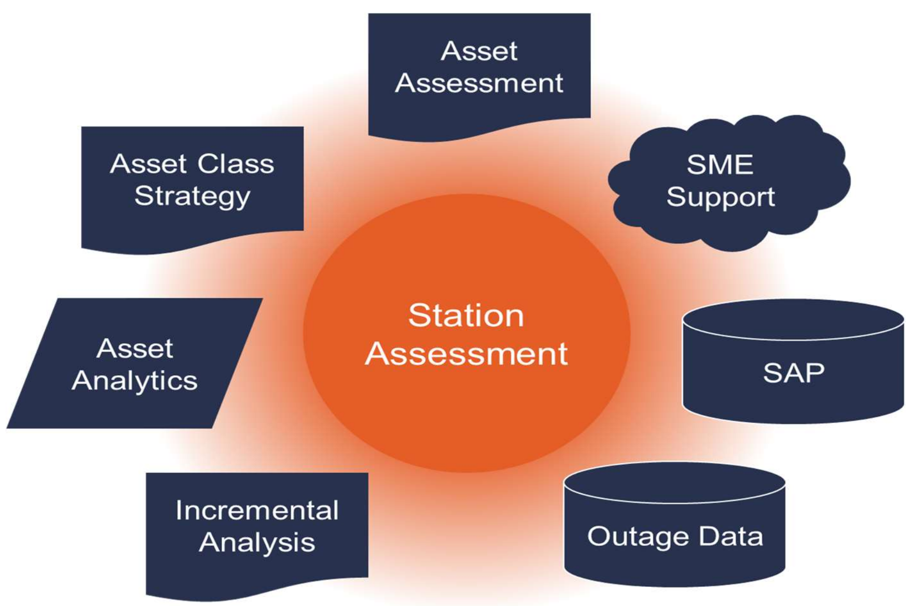


Figure 23. Station Assessment Procedure & Associated Input Data

The above figure illustrates the following process steps/concepts:

- Asset Class Strategy documentation: As discussed in sections 3.1.1-3.2.3;
- Asset Assessment documentation: As explained in sections 3.2.1-3.2.3;
- SME Support: validation of data sources (e.g. AA, outage information, etc.) including site visits;
- SAP: Central storage repository which stores all historical notification, deficiency reports and potential needs reports
- Outage Data: Historical outage frequency and duration data, as supplied within HONI's TODS data historian capability.

In addition, there are a number of incremental analysis sources that serve to provide additional insights into the ARA decision-making process. This includes the following:

- Assessment of stranded load risk;
- Assessment of delivery point performance;
- Capacity constraints analysis: Stations that are nearing capacity represent a greater risk, and changes to the configuration and overall capacity must be accounted for;
- Assessment of short circuit levels;
- Assessment of environmental risks, including PCBs;
- Assessment of physical security Issues;
- Examination of the operating diagram and overall station configuration.

Outputs from station assessment include calculated risk level assessments associated with each component of the substation, along with an overall recommendation as to whether to proceed with a short-term investment candidate, or defer the investments for re-assessment during the long-term planning process (e.g. 10 years).

The above description represents the normal process steps and components comprising the station work asset management review. METSCO understands that each of the three practical scenarios we requested from HONI underwent these analysis steps. METSCO has redacted the unique names and identifiers to focus the discussion on functional process steps, rather than project specifics.

Case 1A: Short-Term Investment Candidate Aligned to AA Results

In accordance with the first scenario, we identified a case study of "ABC TS" where the AA results identified a group of transformers at a single substation with low overall index scores, that were all nearing their ESL criteria based upon their Demographics evaluation score, with three condition scores being in Poor and Very Poor state. This is further illustrated in

Figure 24 for major assets at ABC TS.

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
"ABC" TS	Protection: Electro Mechanical	49	1	100	45	55	0	10	36
	TS	62	34	84	18	32	38	1	36
	Switch: Air Break_115 kV	59	45	100	40	1	100	33	45
	Transformer: Step-down_115 kV	56	27	100	28	30	38	21	37
	Transformer: Step-down_115 kV	42	60	100	16	41	39	21	50
	Transformer: Step-down_115 kV	63	65	100	30	35	37	21	51
	Transformer: Step-down_115 kV	58	70	100	6	45	38	21	53
	Transformer: Step-down_115 kV	60	20	100	42	50	37	21	41
	Transformer: Step-down_115 kV	58	27	100	18	51	38	21	42
	Protection: Electro Mechanical	55	1	100	22	80	0	1	40
	Telecom: MUX Interfaces	8	33	1	100	100	0	1	54
	Switch: Air Break_115 kV	56	45	100	40	1	100	33	45
	Switch: Air Break_115 kV	56	45	100	40	1	100	33	45
	Switch: Air Break_115 kV	57	45	100	40	1	100	33	45
	Switch: Air Break_115 kV	57	45	100	40	1	100	33	45

Figure 24. Station Assessment Procedure & Associated Input Data

Further analysis revealed a number of deficiency reports and potential need issues that had emerged at the substation. These results, which are further illustrated in Figure 25 and Figure 26 respectively, illustrate a number of degradation-related issues affecting the assets installed at the substation, including corrosion, issues with the cooling system and issues concerning the power transformers including oil leaks and low oil levels .

Notification	Functional Loc.	Notif.date	Description
13420045	**"ABC" TS**	10/27/2014	ABC cable tunnel - corrosion
10501739		05/07/2010	ABC BREAKER TCM
10501738		05/07/2010	ABC T11YH BREAKER TCM
10339903		07/28/2009	T14

Figure 25. Open & Outstanding Potential Needs Notifications

Notification	Notif.date	Description
13554852	03/13/2015	AL0368 NT31 Potential Defect DC Mont Cab
13606607	04/10/2015	ABC TS T12 All Cooling Fans
13561546	03/20/2015	Oil barrel at ABC TS T11 March
13547260	03/04/2015	ABC T6 investigation
12686439	10/03/2013	BLDG-Repair&paint ceilings&walls
13507337	01/21/2015	ABC/High Level Non Arc Proof Labels
13430495	11/07/2014	ABC TS T11 Low Oil Level
13430492	11/07/2014	ABC TS T5 Low Oil Level
13430493	11/07/2014	ABC TS T5 Oil leak
13430494	11/07/2014	ABC TS T6 One cooling fan
12941470	04/30/2014	One cooling fan not working.
12770553	11/13/2013	ABC TS T5 Low Oil Level
12786508	11/19/2013	T13 Y winding temp gauge @ABC TS
12686976	10/03/2013	BLDG- 2 Exit doors require caulk
12686967	10/03/2013	ENV- T15 containment curb requires caulk
12686977	10/03/2013	HVAC- A/C Not working
12160981	04/23/2013	T6 TAP CHANGER INDICATION
12160346	04/23/2013	ABC T5 DC ground
12032312	12/12/2012	ABC/Highlevel Nomenclature
11941390	11/12/2012	Roof grounding required
11982533	11/28/2012	ABC T6 low oil
11725780	09/16/2012	ELIGHTS-Batteries need replacing
11794028	10/02/2012	ABC TS T6 Cooling Oil Pump #1
11144277	04/25/2012	ABC TS Ct connection hot spot
10800600	11/21/2011	ABC T14 Loss of cooling alarm
10723412	08/03/2011	ABC TS Fire Panel Malfunction
10721168	07/27/2011	20260 ABC TS ARC FLASH LABELS
10667272	03/17/2011	ABC T6 T/C breather oil leak

Figure 26. Open & Outstanding Deficiency Report Notifications

A final risk analysis (ARA) concluded that there was a need to perform the work in the short term. Results from this risk analysis are further detailed in Figure 23, which include both major and minor asset investments at the station. Transformers T5 and T6 had already been included as part of another planned investment, and so additional investment was established to replace transformers T11, T12 and T13 respectively. Following a deeper investigation and field analysis, it was determined that T14 would be excluded from the investment program and revisited as part of a future initiative.

Asset / Infrastructure	Action	Reason/Rationale	Risk
T11, T12, T13 (including NGR's and surge arresters)	-replace all units including NGR's and surge arresters - fire & noise barriers likely required. To be assessed - spill containment upgrade necessary	-units are running beyond expected service life increasing the probability of failure. -condition of all units is declining with past visible oil leaks. - secondary surge arresters are old porcelain type. - NGR's required for new standard transformers. - spill containment and fire/noise barriers not up to standard.	High
T15 NGR (and HV SA)	-apply NGR as/when appropriate if not already being planned -HV SA may need to be respect due to address TOV.	- to eventually properly ground transformer to allow for eventual removal of grounding transformer at High Level.	Med
T11, T12, T13 Transformer high-side and low-side disconnects	- to be replaced	- declining condition - potential layout change to accommodate new transformers will likely require relocation of these items.	High
SS2 and high-side disconnect	-replace and put in load interrupter also	- SS2 advanced age and poor condition - potential layout change will likely require removal and relocating this equipment.	High
SS1 high-side equipment	-apply high-side fused disconnect and load interrupter	- to bring up to current standards.	High
GT1	-permanently remove when possible	-all new standard transformers have some form of secondary grounding	Med

Asset / Infrastructure	Action	Reason/Rationale	Risk
Current limiting reactors	-will require existing CLR's until three-supply High Level brickclads replaced	- potential layout change may require relocating CLRs.	Med
Potential transformers	- **AR 23630** has replaced 6 sets of delta PT's (T11X, T11Y, T12X, T13X, T13Y and T14X). These should be reused, if feasible, and relocated if necessary. - also replace T14Y and T12Y PTs.	- all units are older style oil-filled units likely containing PCBs. - potential layout change will likely require removal and relocation.	High
Insulators	- for entire station, replace all old porcelain strain insulators with glass-type. - for entire station, replace all cap&pin insulators with station post-type.	- can visually detect early failure of glass strain insulators and they maintain their mechanical strength when sheds may fail. - cap&pin insulators suffer from 'cement growth" failures.	High
Station service switchgear	- replace with standard DESN AC SS transfer scheme. Clean up and remove unused/unnecessary panels and fused disconnects, etc.	- install transfer scheme consistent with new standard and to allow loading of both SS transformers.	High
Revenue Metering	- AR 23630 has installed 8 sets of revenue metering IT's (T11-T14). These should be re-used, where feasible, and relocated if necessary.	-upgrade to current metering standards	High
SS Metering	- PCT Solutions to assess need for station service metering.	-no SS metering currently exists.	Med
Site drainage	- assess condition of drainage infrastructure and upgrade as required.	- Want to ensure drainage system is in good condition and meets standards since yard will be significantly dug up.	High
Existing structures and footings that will remain / be re-used	- For old structures and footings that will be remaining, assess condition. Perform remediation and life extension measures as required.	- to prolong the useful life of existing structure where possible.	High
Tunnel	- preference is to install standard control cable trench and remove old tunnel. However, if continued use is	- certain members appears to be decaying and remediation work would be necessary if tunnel kept.	High

Asset / Infrastructure	Action	Reason/Rationale	Risk
	necessary, then remediate to ensure structurally sound.	- tunnel may possibly interfere with spill containment or cable trenches and new drainage piping.	
Oil Building Removal	-remove old underground oil building	-no longer required. Should be cleaned up and removed. -space will be freed up.	High
Heritage Building	- assess condition of building and how much it would be to remediate or partially remediate for potential use. Assess feasibility of housing 13.8kV switchgear in the building.	- six H1 brickclad breakers/switchgear are at an advanced age and not arcproof. It is strongly recommended to replace this switchgear and preferred to relocate within Heritage building, if feasible, at ABC TS which is a H1 property.	High
Animal Mitigation	- apply all animal mitigation techniques at ABC (ie. cover up and electric fence barrier)	- lessen risk of animal contact outages	High
Fence/Security	- engage Physical Security group about ABC security needs	- Fence may need to be removed to accommodate work and new facilities. Is standard chain link fence or an opaque wall recommended?	High
32 L13W-34	-replace at Development & OGCC request with a circuit switches (Lines Sustainment will scope and fund this).	- this is a very old ABS which requires replacement.	High
High Level A1A2 and A7A8 switchgear	- Preference is to install new H1 A1A2 and A7A8 switchgear at ABC TS in heritage building, if feasible.	- these six H1 brickclad breakers / switchgear are at an advanced age and not arcproof. Old (now redundant) switchgear would remain I/S at High Level and continue to be maintained until THESL is ready replace the full lineup.	High

Figure 27. Overall Recommendations and Risk Results for ABC TS

The above example demonstrates the impact of both AA and ARA processes working together to validate and supplement the findings, resulting in the following positive intervention planning outcomes:

- Assets confirmed by the sequential AA and ARA analysis to be in a deteriorating / "risky" state were fast-tracked for intervention supported by the number of smaller issues identified through review of maintenance logs;

- The assets recommended for fast-tracking were added to the scope of already planned major work at the same station, facilitating potential operating efficiencies within the same geographical and electrical area;

- One component of the originally recommended / prioritized scope of work (T14) was actually excluded from the final scope following the field inspections where SMEs confirmed the insights of analysis, leading to deferral of capital costs.

In this case, both AA and ARA process insights combined to provide incremental economic value. An automatic algorithm-based approach identified assets indicative of serious issues in need of closer examination, while the ARA process confirmed the prioritization identified by AA, with the exception of one major asset that could be deferred for a longer period of time.

Case 2A: Lack of Alignment between AA and ARA Results

As per the second scenario, a case study was identified where the AA results identified a series of oil circuit breakers at "DEF TS" that were under heavy strain based upon their Utilization evaluation score. Majority of the breakers, as illustrated in Figure 24, were identified as having a Condition evaluation category score of just over 50, barely placing them into the Poor condition category.

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality
N-TS-DEFTS-BR-JQ	Breaker: Oil_< 69 kV	43	53	56	13	60	100	29
N-TS-DEFTS-BR-M1	Breaker: Oil_< 69 kV	43	63	56	8	100	96	23
N-TS-DEFNTS-BR-M2	Breaker: Oil_< 69 kV	43	39	56	13	54	93	23
N-TS-DEFNTS-BR-M3	Breaker: Oil_< 69 kV	43	50	56	1	100	93	23
N-TS-DEFNTS-BR-M4	Breaker: Oil_< 69 kV	49	53	78	1	100	98	23
N-TS-DEFNTS-BR-M5	Breaker: Oil_< 69 kV	44	23	60	5	100	96	23
N-TS-DEFNTS-BR-M6	Breaker: Oil_< 69 kV	41	53	49	8	100	92	23
N-TS-DEFNTS-BR-M7	Breaker: Oil_< 69 kV	49	53	78	1	100	96	23
N-TS-DEFNTS-BR-SC1J	Breaker: SF6_< 69 kV	4	13	1	1	1	1	27
N-TS-DEFNTS-BR-T5J	Breaker: Oil_< 69 kV	44	56	60	3	1	100	31
N-TS-DEFNTS-BR-T6Q	Breaker: Oil_< 69 kV	44	53	60	14	1	100	31

Figure 28. Asset Analytics Results for TS Circuit Breakers

However, when assessing the condition and performance results of the associated transformers at this same substation as a part of the broader ARA process, HONI determined that the priority for these major station assets would be very low when compared to the breakers.

The power transformer assets were assessed to be in Very Good condition, translating into low probability of failure. Furthermore, the Performance evaluation scores for these transformers indicated that no historical events had occurred with these assets over the past 5-year period.

Following additional investigations by subject-matter experts, and when accounting for the overall operating configuration of the station and available redundancies, HONI determined that potential impact of breaker failure at this substation would be relatively low.

Therefore, despite the high probability of breaker failure, the low impact of such a failure led to the low overall risk scenario, meaning that minimal incremental investments could be performed, resulting in an acceptable risk level for the continued operation of these circuit breakers into the foreseeable future. Final recommendations were made to revisit and reevaluate the substation after a six-10 year period to re-evaluate the business case for a full or partial rebuild.

This case study demonstrates a practical example of the beneficial tension between the insights provided by the two respective functional components of Hydro One's asset management process. The more holistic evaluation enabled by the work completed at the ARA stage, led Hydro One to conclude that the risks posed by one asset class that was both aging and in poor condition, were not sufficient to move the overall risk to the point where intervention was justifiable, given the condition of other assets, the criticality of the asset and other pertinent factors available through broader analysis and diagnostics.

Importantly, this case study also demonstrates the material risk of relying on insights of a single process – even if it is quantitative and automated - given the multi-dimensional nature of potential asset scenarios, and the multitude of factors that are presently impractical to capture in the form of a single algorithm. As such, the presence of a two-stage process with multiple screens and validity checks, has prevented Hydro One from undertaking an investment that was not ultimately justified at present time.

Case 3A: Short-Term Investment Candidate Identified through ARA Process, but not from AA Framework

In the third scenario, the ARA process confirmed the need for a short-term investment candidate project to replace a group of minor assets at "GEH TS", including surge arrestors, insulators, capacitive voltage transformers and surge capacitors. Although these minor asset classes are supported within the AA framework, in this particular case the input data contained a number of incomplete areas, resulting in the AA tool not producing a score sufficiently high to flag the project as mandating prioritization.

After taking into consideration the input collected through the ARA process, including the raw demographics data, along with the consideration of legacy and obsolete technology contained in the station (along with inputs from the field and SME opinions), HONI determined that a short-term investment was necessary for this particular station.

Although in this example the fact that AA did not flag the investment as needed was a function of data availability rather than some other (less controllable) issue, it represents a realistic and commonly occurring scenario - for HONI and the vast majority of other utilities - in Ontario and beyond. While data availability is improving and will continue to do so, in the present state, the existence of two complementary capabilities/processes such as AA and ARA represents a valuable and prudent transitional solution on the path of process automation of business intelligence work.

3.3.2. *Line Conductor Evaluation*

As per the ARA procedure, line conductor segments are typically replaced as a contiguous group of assets. By replacing a group of segments together as a single investment, HONI seeks to realize operational and financial synergies.

As is the case with Stations assets, results from the AA framework serve as a starting point for evaluation of line conductor assets. In this case, condition results serve as a critical input into the decision-making process, where they are currently available. In particular, torsional ductility and tensile strength results are used as primary indicators to assess if the conductor is at end of life criteria and must be included as part of a short-term investment candidate.

In addition to the AA results, field testing results as provided by LineVue technology are also used to add incremental insights. Historical performance also plays an important role when identifying groups of line segments to replace. For instance, "line outliers" will be identified where sections of line conductor have noted performance issues. Finally, obsolescence also plays an important role where condition analysis indicates that an asset has reached its EOL. METSCO understands that the following three scenarios underwent the AA and ARA assessments as per the approach described above.

Case 1B: Short-Term Investment ARA Candidates Aligned to AA Results

In the first scenario, METSCO reviewed a case study where the AA results identified a group of line conductors on circuit "Dxyz" between "GEH Junction" and "IJK TS" that were all past their ESL thresholds, as determined from their Demographics score, and also in Poor condition as determined by their Condition scores. These results are further illustrated below:

Circuit	Composite RF	Condition RF	Demographics RF	Economics RF	Performance RF	Utilization RF	Criticality RF
	51	65	100	0	1	0	1
	38	0	100	0	1	0	1
"Dxyz"	38	0	100	0	1	0	1
	38	0	100	0	1	0	1
	38	0	100	0	1	0	1

Figure 29. Asset Analytics Results for Circuit Dxyz

It should be noted that the condition results produced for Dxyz would also be applicable to the other adjacent conductor spans and circuits. A laboratory test further validated these results and conclusions. These results are further illustrated in Figure 30.

"Dxyz"

Type : ACSR Designation : 605.0 kcmil 54/7 Nom. Cable Diameter ** : 0.953 in Measured Cable Diameter : 0.870 in

	Alum. Outer Layer		Alum. Middle Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	26,000 psi	Nom. Breaking Strength of	26,000 psi	Nom. Breaking Strength of	26,000 psi	Nom. Breaking Strength of	205,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1059 in	single wire = 229 lbf	0.1059 in	single wire = 229 lbf	0.1059 in	single wire = 229 lbf	0.1059 in	Nom Breaking Strength of single wire = 1,806 lbf
Area of Wire :	0.0088 sq. in		0.0088 sq. in		0.0088 sq. in		0.0088 sq. in	Nom. Load @ 1% Elongation = 1,629 lbf
Number of Wires in Layer :	24		18		12		7	For Tension Test Load @ 1% Elongation **** : Preload = 255 lbf., Offset = 0.010 in.
Number of Wires Tested :	4		4		4		7	
Tension Load for Torsion Test * :	3.29 lbf	= 1.492 kgf	3.29 lbf	= 1.492 kgf	3.29 lbf	= 1.492 kgf	19.06 lbf	= 8.644 kgf
Torsion Test sample length * :	15.21 in	= (120 x dia.+ 2.5")	15.21 in	= (120 x dia.+ 2.5")	15.21 in	= (120 x dia.+ 2.5")	15.21 in	= (120 x dia.+ 2.5")

TEST RESULTS

	Alum. Outer Layer			Alum. Middle Layer			Alum. Inner Layer			Steel and Core Wires			
Measured Wire Diameter : →	0.0980 in			0.0970 in			0.0980 in			0.0960 in			Remaining Zinc [3] % Zinc (avg of wires 1-6) vs. Core Wire
	The outer surface of the alum. wires had :			The outer surface of the alum. wires had :			The outer surface of the alum. wires had :			The outer surface of the steel wires had :			
	Contam	Pitting	Color	Contam	Pitting	Color	Contam	Pitting	Color	Category [1]	Rating [2]	Rust	Pitting
	Moderate	Moderate	Grey	Moderate	Light	Grey	Moderate	Light	Grey	1	1	None	None / 112%
	Comments : The outer surface The inner surface			Comments : The outer surface The inner surface			Comments : The outer surface The inner surface			Comments : The outer surface The inner surface The core wire			
WIRE No.	Number of Turns	Breaking Strength lbf	Breaking Strength psi (calc)	Number of Turns	Breaking Strength lbf	Breaking Strength psi (calc)	Number of Turns	Breaking Strength lbf	Breaking Strength psi (calc)	Number of Turns	Load @ 1% Elongation, lbf	Breaking Strength lbf	Breaking Strength psi (calc)
1	46.8	180	20,436	57.7	192	21,798	61.1	176	19,982	11.1	1311	1495	169,730
2	44.6	189	21,458	56.9	194	22,025	62.7	183	20,776	12.7	1270	1411	160,194
3	42.2	198	22,479	51.2	189	21,458	60.9	205	23,274	13.3	1227	1406	159,626
4	43.1	168	19,073	58.1	168	19,073	63.1	208	23,615	18.3	1261	1450	164,621
5	-	-	-	-	-	-	-	-	-	9.2	1253	1457	165,416
6	-	-	-	-	-	-	-	-	-	27.4	1272	1488	168,936
7 (core wire)	-	-	-	-	-	-	-	-	-	14.2	1297	1490	169,163
Average (Steel & Core 'No. of Turns' is Avg. 1 to 6)	44.2	184	20,862	56.0	186	21,089	62.0	193	21,912	15.3	1,270	1,457	165,384
Avg. Strength x # of Wires in Layer :	(A)	4,410 lbf		(B)	3,344 lbf		(C)	2,316 lbf					
Total Strength of (Aluminum/Steel) :				A+B+C=(D)	10,070 lbf						(E)	10,197 lbf	
Calculated Total Strength of Layer :	(F)	5,496 lbf		(G)	4,122 lbf		(H)	2,748 lbf			(J)	12,640 lbf	
Measured / Calculated (%) :	A/F =	80.2%		B/G =	81.1%		C/H =	84.3%			E/J =	80.7%	
Total Load on Steel @ 1% Elongation :										(K)	8,891 lbf		
Total Measured Breaking Strength :				D+K=(L)	18,961 lbf	= 84.3% of Book Value.							
Derated Meas. Breaking Strength*****				(M)	17,699 lbf	= 78.7% of Book Value.							
Rated Breaking Strength ** (book value) :				(N)	22,500 lbf								

- Shaded areas indicate data manually entered or calculated. (Stored in : Ponc$\Conductor & Skywire Routine Testing) Photo File Number C-2006- 14
See Page 3 for Test Methods and Specifications. See Page 3 for asterisk (*) and footnote explanations.
Note : Please see 'Private Information' on Page 3. Revision 2006-07

Figure 30. Testing Results illustrating Measured Breaking Strength Deficiencies for Circuit Dxyz

This case study demonstrates how the ARA process helps to further validate and build upon the preliminary justification derived from the AA results, while allowing for a broader group of poor-performing conductor segments to be replaced at one time, creating opportunities for cost and planning efficiencies.

Lack of Alignment between AA and ARA Results

As per the second scenario, a case study identified a group of line conductor spans on "Circuit RST" between "LMN" and "IPB JCT" that were past their ESL criteria based upon their Demographics evaluation scoring results. However, the AA condition assessment was missing critical input data. As noted previously, condition results represent the most critical output from AA that is ultimately used in the decision-making procedure. Figure 31 illustrates the raw AA results including condition results on RST-115 which would also be applicable to all adjacent conductor spans.

Line Section	Composite RF	Condition RF	Demographics RF	Economics RF	Performance RF	Utilization RF	Cr
"LMN – IPB Jct".	33	24	100	0	1	0	
	41	0	100	0	1	0	
	41	0	100	0	1	0	
	41	0	100	0	1	0	
	41	0	100	0	1	0	
	31	0	100	0	1	1	
	31	0	100	0	1	1	

Figure 31. Asset Analytics Results for "Circuit RST"

In this case, however, the ultimate prioritization of the investment was driven based upon the obsolete nature and deteriorated condition of the 100-year old conductor type identified through the subsequent ARA analysis. As the conductor in question contain plant fiber cores, it cannot be spliced if a failure were to occur. Accordingly, customers would experience a far more prolonged outage event should a failure take place. For this reason, once HONI established the overall condition and presence of obsolete and deteriorated plant fiber technology, this project became a short-term investment priority, despite the preliminary AA results indicating no apparent issues (albeit as a function of missing data). These plant fiber cores are further illustrated in Figure 32.

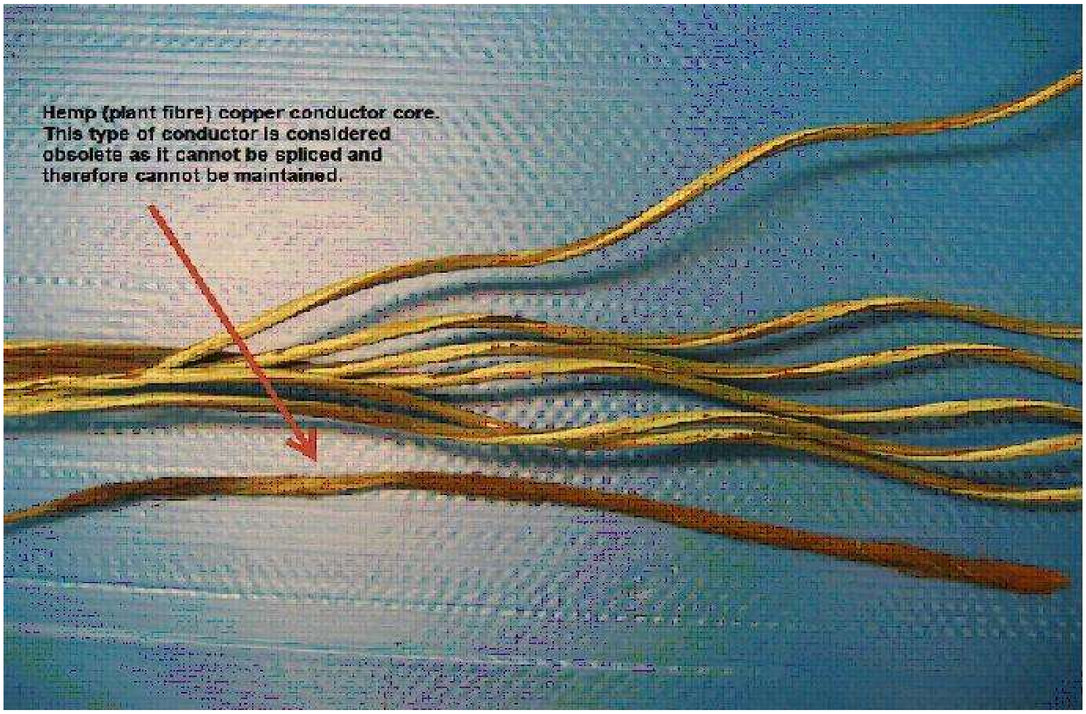


Figure 32. Example of Plant Fibre Core

This scenario therefore demonstrates how the broader ARA procedure provided incremental insights that materially affected the intervention decision due to the consideration of additional information and a discrete standards-related technical obsolescence criterion that would be highly unlikely to be factored into an automated decision support algorithm in the near future. As with the cases related to station investments, the broader ARA framework acted to override the algorithm-driven AA process to yield the combined outcome, superior to those produced by either of the two systems separately.

Case 3B: Short-Term Investment Candidate Identified through ARA Process, but not from AA Framework

As line conductors are modelled in the AA framework, the AA results will always be considered as a starting point to drive any decision-making within the broader ARA procedure. Therefore, there are no scenarios where a short-term investment is formed without any use of AA results.

4. Reliability Risk Model Capability Evaluation

This chapter contains the details of MESTCO's assessment of the Reliability Risk Model (RRM) capability. As noted earlier in this report, we limited our assessment of this tool to the "Overall Capability Sophistication" level of analysis. This is largely a function of the tool's limited application in Hydro One's asset management programs, which at once limits the information available for detailed inquiries and reduces the value of insights these inquiries may produce in the context of asset management process specifically.[8] In light of the tool's comparatively smaller "footprint" on Hydro One's current asset management landscape, METSCO believes that a single level of assessment is sufficient to draw meaningful conclusions about the RRM tool's value proposition.

METSCO employed different criteria for this assessment from those use for the Level 1 assessment of AA and ARA tools, which we see as more relevant for a reliability forecasting tool specifically. Our criteria selection is also consistent with assessments of reliability forecasting capabilities we performed for other utilities in the past. The criteria are:

- Integration and connectivity with the broader asset management procedures;
- Granularity of analysis underlying the forecasting;
- Sophistication of mathematical calculations supporting the model;
- Efficiency of data collection procedures and accuracy of input data; and
- Clear Sense of Current Gaps and Continuous Improvement Plans

4.1. Overall Capability Sophistication Assessment

4.1.1. *Integration into the Asset Management process*

Utilities may have multiple reasons to engage in forecasting of their reliability performance. Most commonly, however, motivation for doing so involves establishing a vision of the anticipated outcomes of planned or contemplated work. The forecasts, typically expressed relative to investment types or levels, may serve as inputs into project selection / investment prioritization process, customer consultation engagements, or performance measure setting activities, among others.

[8] We make this observation in full awareness that HONI utilizes the RRM tool in the customer engagement process, where its outputs enable it to convey asset reliability risk implications to customers. From our perspective, the limited nature to which HONI relies on RRM in asset management is not indicative of the tool's value in customer engagement activities.

While a given tool's forecasting strength comes from the manner its inputs are collected and analyzed (as we discuss in the criteria that follow), its overall value is also determined by the extent to which its outputs are incorporated into AM decisions that take place downstream from forecasting. A mature reliability projection approach should constitute an integrated link between capital and maintenance plans and system performance outcomes.

Where such systems are in place, their underlying reliability projection methodologies can typically be validated by comparing their past projections to actual system performance results for a given year. Where a utility identifies material variances between actual results and those forecasted by the model for the same period, the mechanics of the projection approach are adjusted by way of a standard process, in order to minimize these variances (and their impact on the AM process) going forward.

With respect to Hydro One's RRM model, we found the tool's current level of integration with Hydro One's overall asset management process to be very low. This is largely because the assessment takes place after the AA and ARA processes for a given planning cycle have been completed. Although this still enables Hydro One to consider the feedback from its customers obtained with the help of the model while formulating the nature and magnitude of the investment plan, METSCO considers this work to be outside of the scope of asset management activities, which is the focus of our inquiry.

Equally notable is the fact that RRM does not actually deliver the forecasts of reliability indices, but rather indicates the "risk" level of reliability issues associated with particular investment levels (the fact Hydro One readily acknowledges). The reliability risk derived through the model represents an aging aspect of the key asset classes, as a result of modelling the age distribution and related portion of assets that are expected to experience physical or inspection-based failure on the basis of past data.

Each of the investment level scenarios considered by the RRM includes an estimated failure rate per asset class based on the specific asset age distribution at the end of the modelling period. While the estimated failure rate for key asset classes represents the reliability risk related to the planned asset renewals, it may not be correlated with the actual reliability incidents or equipment availability to serve the load.

While the key implication of a more limited definition of reliability risk in the model is less of a concern for a tool designed to assess the changes in likelihood of certain events taking place based on the nature of actions that precede them, a more complete definition of modelled reliability indicators would provide HONI with deeper insights of the outcomes that it seeks to bring about or avoid.

METSCO recognizes that the manner in which a particular analytics tool is deployed reflects the degree of understanding and confidence that the utility that implemented it has in the model's robustness, accuracy and efficacy. Having been commissioned in 2016, we understand that the RRM model was only available for use (and by extension practical testing) in two annual planning cycles. While Hydro One does not consider the model to be a pilot project per se, the tool's limited utilization to date within an already complex and consequential asset management process is understandable from a practical standpoint.

Considering METSCO's understanding that the RRM tool represents the first instance of HONI using reliability risk modelling in the context of transmission infrastructure, its more robust integration as an explicit AM process input could be considered risky absent extensive practical stress testing.

Based on its current utilization and process positioning relative to other key asset management analytics inputs and decision points, we see Hydro One's use of its reliability risk modelling capability as comparable to less mature industry approaches. However, the sole fact of the utility possessing and using a standalone variety of reliability risk model, rather than using ad-hoc trend-based projections or other more rudimentary approaches, points to a somewhat higher maturity level and a degree of commitment to continuous improvement on the part of Hydro One.

Based on our review of Hydro One's integration of the RRM into the asset management decision making process, we make the following recommendations:

- Enhance the RRM or develop/procure an alternative system to forecast the reliability performance of the transmission system through a variety of *reliability indices*, rather than rely on the *reliability risk* modelling.

- Integrate the enhanced RRM or another forecasting system into the overall asset management process to provide asset managers with a more robust set of reliability outcome predictions based on a variety of investment scenarios under consideration.

4.1.2. *Granularity of analysis underlying the forecasting*

As with most modelling capabilities, the degree of precision of a reliability forecasting model depends on the level of detail of information that the model assesses and takes into account in producing its outputs. In the case of reliability modelling, the relevant granularity variables include:

- *Specificity of replicating the utility's electrical system configuration* – (e.g. presence of feeder- or station-specific operating parameters and performance data, vs. an aggregate reflection of key system parameters);

- *Utilization of outage cause data* – whether the model incorporates all, or only a portion of outage Cause Codes tracked (e.g. only equipment defective vs caused by tree contacts, adverse weather, foreign interference, etc) and use of Sub-Cause Codes.

- *Length of reference periods and forecasting horizons* – the amount of historical data that the model leverages in producing its forecasts, and the duration of the forward-looking forecasting window.

While higher granularity is generally desirable (to the extent that incremental detail drives incremental precision), METSCO notes that the discipline of reliability forecasting is relatively new in the utilities sector, meaning that few utilities in our experience have implemented reliability models of significant granularity. This is particularly the case with respect to the degree of specificity of system modelling. Accordingly, it is important for a reviewer to maintain reasonable expectations when assessing a particular capability.

Having reviewed Hydro One's RRM model, METSCO concludes that the level of granularity of the model's analytical capabilities is low relative to other industry examples known to us. For clarity, our assessment of the RRM is that it lacks granularity characterizing more advanced models. Our finding reflects the following considerations:

- The model's predictions apply to the overall equipment level and three specific asset classes (conductors, breakers and transformers). The model includes key asset classes and sub-categorization of the equipment into the sub-classes that enables a detailed analysis of the investment scenario impact on the projected asset failure rates. Inclusion of additional asset classes[9] (e.g. tower structures,

[9] The RRM includes the reliability issues related to the tower structures and insulators as part of the weighting mechanism to calculate the reliability risk. The model calculates the reliability risk as the weighted average equipment failure rate of three asset classes: conductors, breakers and transformers. The weight score for conductors include all the equipment issues related to lines, covering the tower structures with sub-components and insulators.

insulators, switches) may improve a precision level of the reliability risks associated with the equipment age.

- The RRM is developed to calculate the reliability risks for the equipment on the system level, lacking granular consideration on subs-system levels, such as system regions or large customer groups. In making this observation, METSCO notes that having a reliability model that would provide this level of a more localized predictive analytics would amount to the most advanced tools used by the utilities.

- The RRM model excludes failure data related to non-equipment phenomena – outage causes like weather events, adverse environment, human related errors, foreign interference, etc., are not factored into the reliability risk projection. We recognize that inclusion of other reliability cause codes into the model is a relatively large undertaking for the utility that requires a sophisticated historical analysis of all the cause codes to find the significant external and internal drivers impacting the reliability indicators.

- The model calculates reliability risk of the system relying on the asset replacement counts included in the investment scenarios. While replacing the assets on bad condition represents one of the most impactful option to mitigate the reliability risks, Hydro One may have other non-renewal projects that aim to improve the transmission system performance (e.g. adding protection devices in the system, increasing system capacity, new lines, etc.). Excluding the impact of such non-renewal projects (if they exist in in the investment plan) may skew the overall assessment of the reliability risk.

- The horizon period of the RRM extends to the next five years. Due to a longevity of the transmission assets and a complexity of the transmission related construction projects, the model may need to cover a longer horizon period to gain a better understanding of a long-term impact on the investment scenarios on the system.

In short, the RRM tool trails the industry in terms of the level of detail embedded in its inputs, outputs and governing relationships. The model also focuses only on outages related to equipment end of life, excluding the data related to other material drivers of reliability performance. Although this exclusion may be explained by the utility's desire to concentrate on the impact of equipment-related performance only, the results of such analysis bear a significant risk of painting an incomplete picture, considering, for example, the typically observed correlations between weather and defective equipment failures, (among others) that the model does not presently capture.

For reasons listed above, we conclude that the RRM model lacks granularity when compared to other industry participants that possess dedicated reliability models. However, the fact that a standalone reliability risk model has been developed, positions HONI amongst only few utilities that have this predictive capability to perform reliability risk forecasting.

Based on our review of the granularity of the RRM, we make the following recommendations for Hydro One's consideration:

- Enhance the present model or ensure that an alternative solution include additional asset classes (e.g. tower structures, insulators, switches) and sub-classes to improve the precision level of the equipment related reliability risk forecasting.

- Develop capabilities to provide reliability risk prediction on a sub-system level, such as system regions or large customer groups.

- Factor in non-equipment related outages (e.g. weather events, adverse environment, human related errors, foreign interference, etc.) to forecast the reliability risks of the transmission system as a whole.

- Assess the reliability impact of the non-renewal projects in the RRM or alternative capability. If the utility does not have any such projects in the investment plan, then the benefits of this recommendation would not outweigh the costs of developing this capability.

- Extend the forecasting horizon to at least ten years to capture a greater extent of the long-lasting renewal and non-renewal projects within the investment scenarios on the system reliability.

4.1.3. *Sophistication of mathematical calculations supporting the model*;

As with AM integration and data granularity, reliability forecasting methods and models can vary substantially in terms of complexity of calculation to model relationships between investment levels and system reliability outcomes.

At the most basic level, reliability forecasting approaches leverage trend analysis of interruption data, extending the past trends into the future with a variety of normalization techniques to smooth out volatility, or establish the bounds of reasonable performance ranges. More advanced systems utilize econometric techniques to establish mathematical relationships between asset failure instances or modes, and factors that precipitate them, such as demographic data, condition parameters, weather/climate phenomena and other types of conditions related to outages.

Models may differ significantly by predictive power of their underlying regression equations, number of modelled factors, or the type of analysis they use to define the relationships between variables (e.g. linear, logarithmic, etc.). Finally, the algorithms for the most sophisticated models will feature advanced tools of statistical analysis that capture and appropriately treat complex interactions between a multitude of factors, and account for the technical and physical factors inherent in a given system and the environment that surrounds it.

In the case of Hydro One's RRM, calculated changes in reliability risk are grounded in two factors – asset demographics and probability of physical and inspection-based failure by age across three asset classes (conductors, transformers, breakers) and sub-classes. For each investment scenario it analyses, the model starts by forecasting the demographic profile of Hydro One's asset base over the forecasting period, using these major asset types as a proxy for the system as a whole.

Having derived the forecasted demographic distribution, the model then applies statistical asset failure curves derived from Hydro One's actual field data (and supported by 2014 Asset Failure Analysis report conducted by Foster Associates), to estimate the number of assets expected to reach their end-of-life during the forecast period.

The resulting number of forecasted failure retirements is then adjusted to reflect the planned replacement volumes underlying each investment scenario. The model then calculates the total failure rate per each asset class by dividing total retirements by asset counts in each of the asset classes, and the failure rates by assigning "significance weighting" to each asset type. Significance weighting is based on the relative likelihood of a particular type of asset to contribute to the reliability issues, according to Hydro One's historical reliability data.

The resulting rate (%) represents the relative reliability risk underlying a particular investment scenario. The difference between the retirement rates associated with each scenario represents the directional difference in reliability across the potential investment scenarios – the model's ultimate output used in stakeholdering.

METSCO notes that there are several modelled assumptions that would need to be improved upon, should HONI elect to further utilize the RRM to calculate the aging equipment reliability risk. Currently, the replacement priority within each of the scenarios is based on the oldest assets to be replaced first within the asset count limits established by the each of the investment scenarios. This approach does not account for the end-of-life asset retirements that naturally occur as a result of the aging process and are modeled in the RRM by the asset failure curve and age demographics. Under these replacement algorithms, the changes in the reliability risk values may be over- or under-estimated.

In METSCO's assessment, HONI reasonably designed the significant weights to represent a contribution of each of the asset classes in the equipment reliability risk. The model uses the weights constructed from the outage database and filtered by the equipment cause code. However, the conductor weighting incorporates any issues originated in transmission lines, for example including the reliability issues caused by tower structures and its subcomponents, as well as insulators. The same approach is assumed for transformer and breaker weightings. By combining the reliability cause codes unrelated to the core asset class, the final weightings have a potential to skew the reliability risk values calculated by the model.

As the preceding description may indicate, while the RRM does employ a variation of equipment hazard rate sourced from HONI field data in deriving its projections, the ultimate output that the model relies on significant assumptions, while leaving unaddressed a number of other statistical relationships where meaningful correlations and/or causal relationships could be reasonably expected. In its present form, the model's actual forecasting output is the rate of anticipated asset retirements, while the assumed relationship between the changes in this rate and equipment outages is significantly less robust.

Utilization of hazard rates and the age distribution to forecast the reliability risks associated with the equipment can be considered as a big first step forward in deploying the reliability forecasting capabilities in the asset management decision making process. In consideration of the above-noted characteristics, METSCO rates the sophistication of the RRM model's mathematical calculation as relatively modest, when compared to dedicated reliability modelling tools employed by some utilities.

In making this conclusion, however, we note that a large number of Canadian utilities do not engage in forecasting of reliability in any organized form. This is particularly true of transmission systems, the multi-contingency nature of which makes it more challenging to construct the relationships between potential equipment failures and actual outages experienced by end customers, be they transmission- or distribution-connected. Nevertheless, we see significant opportunities for improvement in computational sophistication of HONI's model, provided the utility's management is considering expanding the manner of the model's utilization in the coming years.

Based on our review of the model algorithms deployed in the RRM, we make the following recommendations for Hydro One's consideration with respect to potential RRM enhancements or development of a new capability:

- Enhance the algorithms utilized to calculate the demographic profile for each asset class, by revisiting the priority of asset replacements and considering both reactive and inspection-determined failure modes of assets reaching their ends of lives.

- Revise asset class weights or the algorithms that calculate the reliability risk of three key asset classes per each investment scenario to incorporate more asset-specific failure considerations.

- Utilize a variety of econometric techniques to establish mathematical relationships between the non-asset and asset-related failure instances or modes, and factors that precipitate them.

4.1.4. *Efficiency of data collection procedures and accuracy of input data*

For any modelling tool, the quality of its input data and the effort involved in its collection and verification are important factors in determining that model's overall reliability. While METSCO understands that the IT systems used to report and validate Hydro One's transmission reliability statistics are advanced, robust, and undergo extensive verification on a regular basis, these systems are not directly integrated with the Reliability Risk Model. In performing its runs, it is sufficient for the model to utilize the latest demographics data available from the utility's enterprise systems, and the equipment hazard rate curves validated by the 2014 Foster and Associates report. As we discussed earlier, Hydro One's enterprise systems are well integrated, and incorporate a number of data verification steps, meaning that we are aware of no particular issues that would point at concerns with the currency of demographic data

We understand, however, that HONI manually filters its outage data to identify the cause codes and events associated with each of the equipment types in scope of the present RRM analysis. While this manual procedure is inefficient and potentially prone to entry errors, automation of this process may be relatively expensive and not worth the efforts given the narrow scope of the tool's application.

In light of the relatively modest data needs and the robustness of the enterprise systems that generate the demographic information, METSCO has no concerns regarding data accuracy or efficiency of data collection associated with the RRM capability.

4.1.5. *Clear Sense of Current Gaps and Continuous Improvement Plans*

In our discussions surrounding the RRM with Hydro One subject matter experts, we found them to be both realistic in terms of recognizing the tool's present capabilities, their limitations, and receptive to the ideas regarding potential improvement opportunities in the field of reliability forecasting.

During these discussions, Hydro One SMEs brought up the issue of methodological complexity of forecasting transmission system reliability indices, in light of the multi-contingency nature of a large portion of the utility's system, which prevents all equipment outages from manifesting themselves in the form customer interruptions. In this context, HONI staff hypothesized of forms of forecasting transmission system performance alternative to average interruption frequency and duration indices, such as system nodes, equipment availability indices, loads at risk, etc.

METSCO is of the opinion that index-based transmission reliability forecasting is feasible based on our past experience in reviewing and constructing such models. However, we see Hydro One's commentary regarding alternative paths of enhancing a given solution, as a strong indication of the company's motivation to continuously improve – but to do so in a manner that fits the company's operational environment and provides incremental value in the areas where they are most needed.

Considering the relative recency of its introduction, the RRM is yet to undergo any formal reviews or enhancements, which METSCO finds to be reasonable. However, we see the fact of Hydro One's decision to implement (albeit in a limited role) a capability that many transmitters are only beginning to contemplate, as the best practical indication of the culture of continuous improvement on the part of its Asset Management function and its management.

While the RRM trails the advanced industry practices in many respects, it provides the company with a strong foundation upon which to enhance its forecasting capability going forward.

Based on our review of the continuous improvement plans, we make the following recommendations:

- Prior to investing any incremental resources into potential refinements or alternative solutions, we encourage Hydro One's management to fully articulate a vision of the tool's ultimate place within its asset management and capital planning hierarchy, including whether such a tool is ultimately needed in light of all other capabilities.

- Once this process (which we understand to be underway) is complete, Hydro one can choose to develop a critical path and timeline towards further enhancements, if desired.

V Conclusion and Recommendations

In setting out to conduct this assessment, METSCO sought to provide a comprehensive review of Hydro One's asset analytics and reliability risk modelling capabilities across a number of dimensions. Having conducted more than 30 interviews with Hydro One SMEs, along with extensive independent review of the materials supplied by the utility, we dedicate a considerable amount of attention to the technical details related to scope and nature of inputs, data availability and validation, and practical case studies.

We also saw it as critically important to assess the higher-order managerial variables related to process coherency, reflection of best practices, and the degree of comprehensibility of the processes and their implications. These key organizational factors are often left out of the scope of purely technical assessments, leading to limited insights as to the practical utility of a given capability on a day-to-day basis. While some of these issues may not have a critical bearing on the outcome of a single assessment, their effect may compound across the investment cycles and individual processes, resulting in lost productivity, complacency with status quo, and a number of other negative consequences.

On balance of factors and practical examples considered across the three levels of assessment, it is METSCO's opinion that the AA and ARA capabilities, which represent the backbone of Hydro One's asset management analytics, are comparable to advanced asset management tools used by other utilities of similar size and sophistication. In a number of areas - such as the integration of analytics tools with the enterprise data management systems and condition assessment techniques for conductor infrastructure – we find Hydro One to be at the sector best practices level.

Importantly, when validating our Level One and Two impressions by way of a case study review in the Level Three of our framework, we saw the two parts of Hydro One's asset management capabilities working as intended – providing complementary insights that enhanced, validated, and in some cases disputed the implications of one analytical tool or process relative to those provided by its counterpart. The outcomes of this multi-stage / multi-criteria review and stress-testing were consistent with the tools' intended purpose of optimizing the value of the ultimate investments proposed. In several cases analyzed, the combination of several discrete tools and processes actually led to lowering immediate investment requirements than would otherwise be these case if only one of the two complementary capabilities was used.

Critically, our case studies also highlight the potential pitfalls of relying exclusively on the insights delivered by algorithm-driven automatically generated analytics capabilities. While automated analytics tools like AA are sufficiently rigorous and robust to deliver value to Hydro One's asset managers, the multitude of potential scenarios that manifest themselves in the context of utility planning cannot be reasonably expected to be fully captured by an algorithm at this time. Accordingly, and as illustrated by our case studies, the complementary use of the automated fully formulaic tools along with the more holistic approaches, is positioned to provide the utility with additional value – at times proactively mitigating the financial impact of suboptimal investments recommended by one tool or another.

Our conclusions are less favourable with respect to the RRM tool – which is both relatively new and currently used in a very narrow context of directional reliability risk quantification for customer engagement, rather than asset management per se. While we find that the RRM tool trails most other reliability forecasting capabilities known to us, we see it as important to contextualize this finding by stating that very few transmission utilities currently possess dedicated standalone quantitative tools, or even fully formalized processes for reliability forecasting or a related activity. As such, the fact of Hydro One's possession of such a standalone model (albeit in a fairy scoped form) represents an important step on the road to continuous improvement that sets the utility apart from many of its peers.

Throughout this report, we provide Hydro One's management with a number of recommendations about potential enhancements that it may want to consider to further refine and solidify its quantitative analytics capabilities. While all of these reflect METSCO's sector experience and proactive research endeavors, we are cognizant of the reality that Hydro One's resources available for potential implementation of any of the changes that we advocate are likely to be insufficient to implement all of them over the next five-year rate cycle, or even beyond.

Based on these considerations, our overarching recommendation is that Hydro One consider our individual suggestions as potential options for further enhancements, viewing them in the context of their opportunity costs relative to other operating and customer-oriented priorities. Selecting the areas where attaining best practices may not necessarily be a priority (especially when validated through customer engagement, value for money testing, etc.) is one of the few areas where regulated utilities have a meaningful degree of strategy-setting discretion.

Notwithstanding the above comments, the following is the list of recommendations that we recommend that Hydro One consider in its efforts of continuous improvement.

AA/ARA capabilities:

1. Consider clearly separating the risk factors/criteria in AA to (a) define probability of failure of a specific asset, and (b) incorporate the impact of asset failure to explicitly assess a broader variety of outage consequence costs, such as utility's and socioeconomic costs, including the costs associated with the environment, safety/collateral damages, environment, customer interruption costs and financial impacts. Given that many of these additional factors proposed for incorporation into AA are already considered in the subsequent ARA analysis, we qualify this recommendation by stating that HONI may wish to consider it at a juncture where a broader AM process reorganization may be contemplated.

2. Re-visit the formulation of its present AA framework and consider potential regrouping / renaming of assessment factors components to better align it with commonly understood industry terminology (such as condition assessment/health index, or impact assessment/consequence cost), and take steps to develop more comprehensive explanatory manuals for its AA capabilities.

3. Continue ongoing work to rectify data completeness gaps identified across the individual risk sub-categories for each asset class in section 3.2, aiming for the highest practicable scores within the resource availabilities, and prioritizing the categories seen as most impactful in light of the criteria weightings.

4. Consider supplementing the current condition parameters tracked for each major asset class with additional parameters tracked in the industry, as identified in the appropriate subsections of section 3.2. As with all input enhancements, evaluate the incremental value proposition of additional parameters relative to the implementation costs by way of financial value for money analysis.

5. Consider integration socio-economic factors, including costs to the customer (customer interruption costs), as well as environmental and safety-related monetary cost factors, such that the full range of economic costs (including those that go beyond those incurred by a utility or its customers) can be utilized as part of this evaluation procedure.

6. Consider supplementing the obsolescence-based intervention assessments for Protection, Control, and Telecom assets by formally incorporating the results of manual SME activities that already occur in a less formalized manner.

RRM capability:

7. Prior to investing any incremental resources into potential refinements, we encourage Hydro One's management to fully articulate a vision of the tool's ultimate place within its asset management and capital planning hierarchy, including whether such a tool is ultimately needed in light of all other capabilities.

Subject to the outcome of deliberations suggested in the above recommendation, consider further enhancements to reliability forecasting through an RRM, or an alternative solution.

8. Enhance reliability forecasting to assess reliability performance of the transmission system through a variety of reliability indices, rather than rely on the reliability risk modelling.

9. Integrate the enhanced reliability forecasting solution into the overall asset management process to provide the asset managers with a more robust set of reliability outcome predictions based on a variety of investment scenarios under consideration.

10. Include additional asset classes into the reliability forecasting approach (e.g. tower structures, insulators, switches) and sub-classes to improve the precision level of equipment related risk forecasting.

11. Develop a capability to provide reliability risk prediction on a sub-system level, such as system regions or large customer groups.

12. Expand the overall approach to reliability / reliability risk forecasting to factor in non-equipment related outages (e.g. weather events, adverse environment, human related errors, foreign interference, etc.) to forecast the reliability risks of the transmission system as a whole.

13. Assess the reliability impact of the non-renewal projects in the enhanced reliability forecasting solution. If the utility does not have any such projects in the investment plan, than the benefits of this recommendation are not expected to outweigh the costs of developing this capability.

14. Extend the reliability forecasting horizon to at least ten years to capture a greater extent of the long-lasting renewal and non-renewal projects within the investment scenarios on the system reliability.

15. Enhance the algorithms utilized to calculate the age demographic profile for each asset class, by revisiting the priority of asset replacements and considering both reactive and inspection-determined failure modes of assets reaching their ends of lives.

16. Revise asset class weights or the algorithms that calculate the reliability risk of three key asset classes per each investment scenario to incorporate more asset-specific failure considerations.

17. Utilize a variety of econometric techniques to establish mathematical relationships between the non-asset and asset-related failure instances or modes, and factors that precipitate them.

METSCO trusts that these recommendations will provide Hydro One's management with a number of strategic options to consider in the coming planning cycles.

VI References

[1] "Planning Process", Hydro One Networks Inc., 2017.

[2] "Asset Management Workshop", Hydro One Networks Inc., 2017.

[3] R.E. White, "2014 Asset Failure Analysis", Foster Associates, 2014.

[4] "Asset Management Strategy Document – Transformer Asset Strategy", Hydro One Networks Inc., 2017.

[5] "Asset Management Strategy Document – HV and MV Circuit Breaker Asset Strategy", Hydro One Networks Inc., 2017.

[6] "Evaluation of Hydro One Conductor Assessment Program", Electric Power Research Institute (EPRI), 2016.

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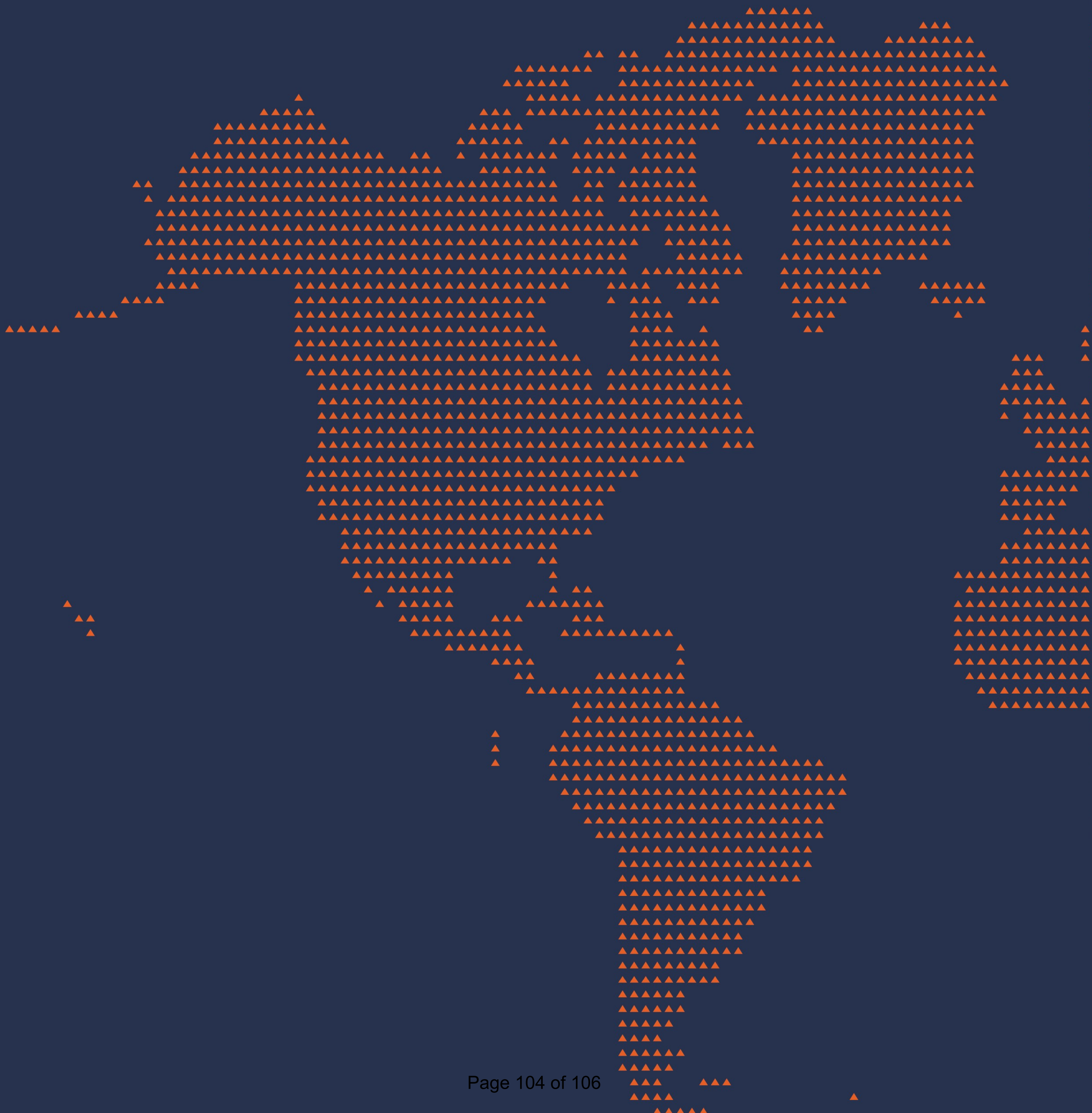


FORM A

Proceeding:………………………

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ROBERT OTAL (*name)*. I live at BOLTON (*city)*, in the PROVINCE (*province/state*) of ONTARIO .

2. I have been engaged by or on behalf of HYDRO ONE NETWORKS INC. (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date MAY 31st, 2018

Signature

FORM A

Proceeding:………………………

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ALEXANDER BAKULEV (*name*). I live at TORONTO (*city*), in the PROVINCE (*province/state*) of ONTARIO .

2. I have been engaged by or on behalf of HYDRO ONE NETWORKS INC. (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date MAY 31st, 2018

____
Signature

Assessing Hydro One's Investment Planning Process
Final Report
March 13, 2018

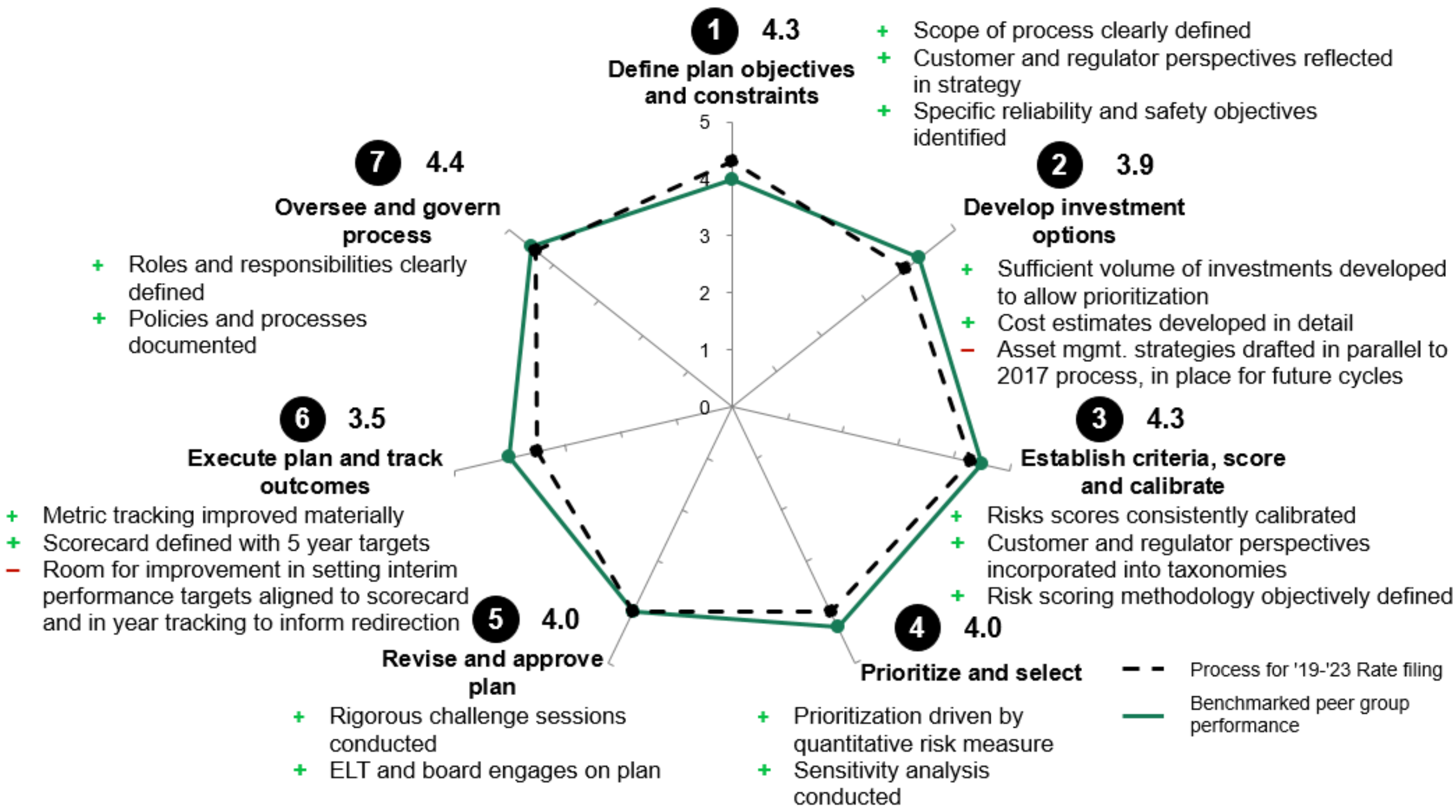
I. Executive Summary

Since its initial public offering in late 2015, Hydro One has undergone significant organizational change as it transitions towards being a more commercially oriented utility. As part of this effort, Hydro One has taken steps to address gaps in its planning process that have been identified both internally and by the Ontario Energy Board (OEB) in its previous Transmission decisions. In its last decision, the OEB ordered that Hydro One conduct a third party review of its investment planning and condition assessment processes. This report aims to address the OEB's request for a review of the investment planning process. In it, we (the Boston Consulting Group) provide our assessment of recent efforts to improve the planning process at Hydro One, and the resulting process undertaken in 2017 in support of Hydro One's 2019-2023 Transmission Rate Application (subsequently referred to as the "2017 Process" or "2017 Plan").

To conduct this assessment, we outlined a set of capabilities typically required to execute an investment planning process competently. These were drawn from two sources – ISO 55000 asset management standards and industry best practices gathered through interviews with experts and through the Boston Consulting Group's (BCG) experience working with leading utilities globally. We developed a framework encompassing the key elements of an investment planning process, and developed scoring rubrics that codified capabilities and best practices across each element of the process. We defined a spectrum of performance on each capability on a scale from 1 to 5. We assessed Hydro One's 2017 process against this framework to understand how Hydro One compares with asset management standards and peer utility performance.

Overall, Hydro One has implemented a consistent, thorough planning process that meets or exceeds expectations for a typical utility planning process in all areas. Exhibit 1 below offers a comparison of Hydro One's performance on its 2017 planning process against our selected peer set.

Exhibit 1: Summary of overall maturity assessment of Hydro One's 2017 Planning Process



In our assessment, Hydro One's planning process demonstrates key strengths in several areas:

- Inclusion of customer input in the investment plan: Hydro One's incorporation of customer input throughout its planning process exceeds what we have observed in many peer utilities, partially due to the relatively high expectations of the OEB for gathering customer input when compared to other jurisdictions. Hydro One has incorporated customer perspectives in its plan objectives, in developing individual investments, in evaluating the risk profiles of investments and in considering the outcomes that its optimized portfolio of investments ultimately delivers.

- Risk scoring: Hydro One implemented a revised risk-scoring process that introduced greater objectivity and reduced complexity when compared to its prior process.
- Identifying mandatory investments: Hydro One's revised scoring process enabled clearer distinctions of mandatory vs. discretionary investments included in the investment plan.
- Enterprise engagement: Hydro One extended the timeframe for plan review and internal stakeholder engagement, leading to more thorough engagement with draft plans at all levels of the organization.
- Productivity: Hydro One undertook an effort to improve its tracking of outcomes and metrics, including productivity and cost metrics, enabling better tracking of its efforts to improve the efficiency with which Hydro One executes its plans.
- Governance: In introducing its revised process, Hydro One had an opportunity to improve governance by codifying many of the details around investment planning. This included, but was not limited to, roles and responsibilities, process steps and timing, and education materials.

In reviewing the planning process, we identified three key areas where Hydro One is continuing to make progress towards a level consistent with peer utilities. Hydro One communicated the details of the plans that have been put in place to continue to progress on these dimensions in future planning cycles:

1. Investment Development: Hydro One has made significant progress in ensuring its investment plans, and specifically its sustainment investments, are driven by an understanding of system and asset condition, but can continue to focus on developing potential investments using a rigorous, data-driven process. Hydro One aims to conduct condition testing on all end of life assets, and has processes in place to test critical stations and lines equipment. However, for some assets where a large share of the asset base is reaching end of life (e.g. conductors, insulators), Hydro One faces a backlog in condition

testing. As a result, testing data is not available for all end of life assets, consistent with circumstances faced by many utilities with aging asset bases.

Hydro One is working to address the backlog in condition data for these assets by enlisting third party support to complete condition testing on end of life assets; in developing the 2017 plan, they relied on existing data and experienced planner judgment to develop investment candidates.

2. Asset Strategies: Hydro One conducted a significant effort to update its asset strategies in parallel to its most recent planning cycle. Having updated asset strategies will strengthen Hydro One's asset management capabilities going forward. However, the parallel effort resulted in some asset strategies not yet being in place for the onset of 2017 planning process. Teams were able to leverage legacy asset strategies as they developed the 2017 plan, and the investments included in the plan align with the finalized asset strategies. As a result, the parallel nature of the asset strategy effort had limited impact on the quality of the plan.
3. Outcomes Tracking: In 2017, Hydro One was able to translate the results of its investment plan into expected customer outcomes with greater specificity than it had in previous years, leading to 5 year targets for key scorecard metrics. As Hydro One tracks actual performance against its forecasted outcomes, there is an opportunity to refine the accuracy of its forecasting methodology for future years; this will help Hydro One more accurately predict the outcomes provided by its investment portfolio. We would also recommend Hydro One leverage the same methodology to forecast 1 year outcomes for its scorecard metrics, in addition to the 5 year forecasts already in place.

We believe that Hydro One's performance in executing its planning process is consistent with what we have observed in the selected peer set of leading utilities. While we have identified a few areas where Hydro One has demonstrated more limited maturity than leading utility peers, in our view, their performance on these dimensions has not materially impacted the quality of the plan. As Hydro One continues to focus on improving the planning process, investment plans will be expected to continue to increase in quality.

As Hydro One considers how to continue to progress towards having a best in class planning process, we would recommend they focus on the following actions:

- Investment Development:
  - Continue to clear the backlog in condition testing for critical assets, and ensure that steady state plans allow for ongoing condition data gathering as assets age.
- Asset Strategies:
  - Continue to ensure asset strategies are in place to guide investment development and updated to ensure relevancy.
- Outcomes Tracking:
  - Continue the implementation of plans to use performance data to enhance outcome forecasting capabilities.
  - Set interim annual targets for scorecard metrics to facilitate tracking towards five year goals outlined in Hydro One's regulatory scorecard.

II. Background and context for this report

The 2019-2023 Transmission rate application will be Hydro One's third major application in the three years since it became a public company. This application follows Hydro One's previous 2-year Transmission cost of service filing (EB-2016-0160), submitted in 2016 and decided by the OEB in September 2017, and its 5-year Distribution rate application (EB-2017-0049), which is currently under review by the OEB. In parallel to these filings, Hydro One has also been undergoing significant organizational change as it transitions from provincial to public ownership, which has included significant changes in personnel and processes, including revisions to the investment planning process.

In its last transmission decision, the OEB found several areas of concern with Hydro One's Transmission System Plan (TSP) and how Hydro One conducted its capital investment planning process, notably the timing of development of various inputs, the consistency of condition data collection, and the use of data to inform the levels and mix of spending in the investment plan. As a result of these concerns, the OEB required that Hydro One submit an independent, third-party review of the asset condition assessment and capital investment planning processes. Hydro One chose to respond to this request with two separate reviews: an asset condition assessment process review, conducted by a different third-party reviewer, and a capital investment planning review, which we include in this report. Our aim is to provide the OEB with an objective assessment of Hydro One's current planning process, including changes to the process since the last filing, in order to satisfy the OEB requirement and facilitate its evaluation of the TSP included in Hydro One's 2019-2023 Transmission application.

Our firm (BCG) has extensive credentials in process management, capital planning, and the utility industry that enable us to conduct this assessment. BCG is a leading global consulting firm with over 14,000 employees and 90 offices in 50 countries. More than 10% of the firm's leadership is dedicated to serving energy clients, and the energy practice is supported by a knowledge team of 35 analysts who conduct projects for clients and contribute the firm's thought leadership on energy topics. We have completed more than 2,500 energy projects in the past five years, and have worked with 15 of the 25 largest global utilities.[1] The team conducting this review consisted of senior leadership with extensive experience in utility operations, utility capital planning, and large capital project management globally and in Canada. The team also consisted of executing team members with significant experience in regulated utility operations and regulatory strategy in the US and Canada, including in Ontario. Additional detail on BCG's credentials is included in the appendix.

III. Overview of approach and process

Our approach to this review was to develop a comprehensive set of capital planning best practices, and assess Hydro One's relative performance compared to "best in class" processes and

[1] Largest utilities as defined by 2016 Platts Global Energy Corporations

industry standards. We leveraged two main sources to develop a comprehensive list of standards and best practices:

- ISO 55000 Asset Management Standards: ISO 55000 standards are industry-agnostic standards set forth by the International Standards Organization that outline required capabilities for competent asset management processes. Investment planning represents a key component of overall asset management as defined by the ISO, and thus many of the standards apply to this subset of the overall process.
- Industry Best Practices: We have observed additional best practices that define best-in-class capital planning processes and form the second component of this assessment. Reviewing industry best practices helped us identify capabilities not explicitly outlined by the ISO but required for a strong planning process.

To develop this assessment, we leveraged BCG experts' thousands of hours working in the utility industry; we supplemented our experience with information collected from interviews with experts on utility planning practices and asset management, conducted over 6 weeks while preparing this report. In Exhibit 2, we include a list of specific utilities whose planning processes we studied to develop our benchmarks and best practices (additional detail on the utilities reviewed is included in the appendix):

Exhibit 2: Utility planning processes reviewed in developing benchmarks:

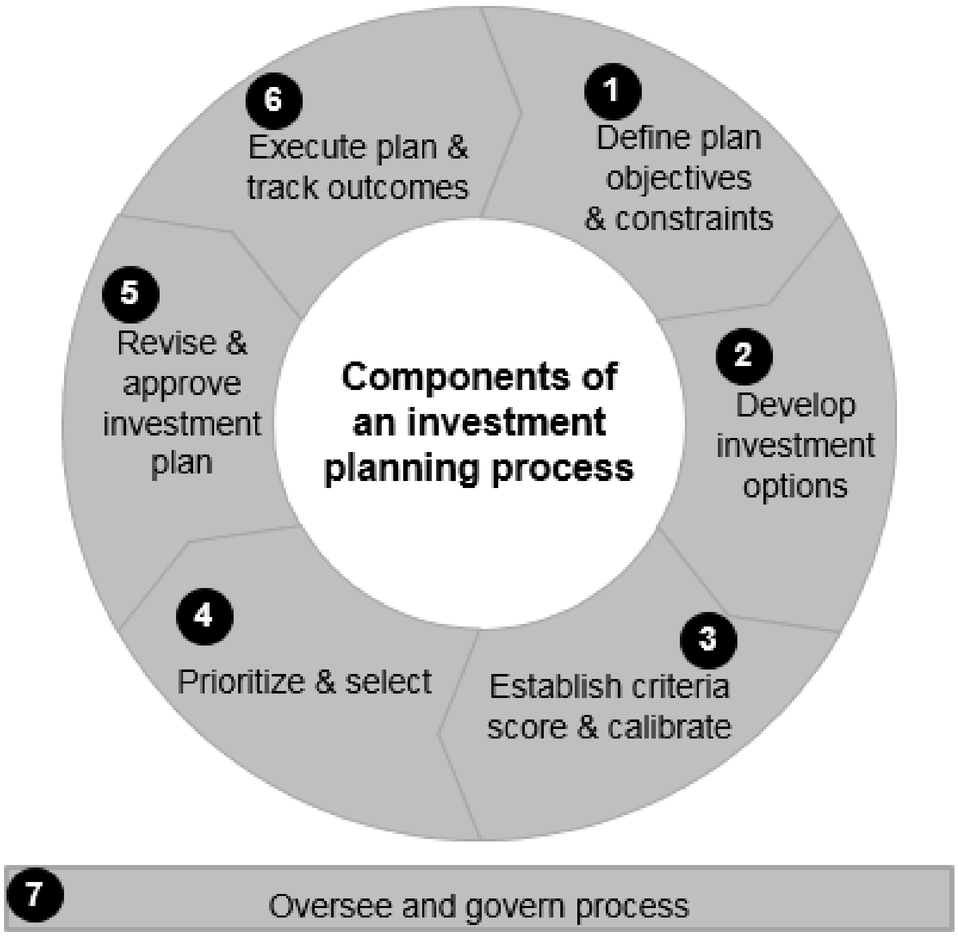
Utilities reviewed in benchmarking	
Hydro Quebec	National Grid
Berkshire Hathaway Energy	Enbridge Gas Distribution Inc.
Pacific Gas and Electric Company	BC Hydro
LS Power	Exelon
Iberdrola USA	Xcel Energy
Southern California Edison	Southern Carolina Electric and Gas
Consolidated Edison	Hanergy
Additional expertise consulted to guide assessment	
ISO-55000 implementation expert	Former Ontario Energy Board panel member

We selected a peer set that in our experience represents above average performers in utility planning, as we were seeking to understand planning processes that would help us define the characteristics of a "best in class" utility.

We recognize that the planning process for any utility is influenced by its regulatory environment and regulators' expectations, and that some elements of Hydro One's planning process are influenced by the OEB's expectations. However, we are not experts on Ontario regulation, and so have not evaluated Hydro One on any capabilities that would be explicitly required by the OEB. Rather, we have leveraged our broad-based expertise on utility capital planning across North American utilities to assess Hydro One's planning process against other utilities and against industry and jurisdiction agnostic ISO standards. In areas where parts of Hydro One's process are shaped by the OEB's requirements, we have noted the difference from peer performance, but have not assessed Hydro One's ability to meet those requirements.

We began our evaluation by developing an assessment framework. We identified 7 key elements of the planning process and defined the detailed capabilities required for a company to successfully carry out its planning process.

Exhibit 3: Components of an investment planning process



The elements are defined as follows, with the some of the key capabilities required for each element listed below and additional detail in the exhibits accompanying our evaluation:

1. Define plan objectives and constraints:
    - Incorporate corporate and operations strategy into the investment plan
    - Incorporate customer and regulatory perspectives into plan development
    - Define financial envelopes and other key constraints for the planning process

2. Develop investment options:
    - Develop candidate investments informed by condition data
    - Develop alternatives to preferred investments

3. Establish criteria, score and calibrate:
    - Identify potential risks mitigated by candidate investments

- Calibrate risks to ensure consistent application across investment types

4. Prioritize and select:
    - Use defined criteria to prioritize the universe of investments
    - Narrow the universe of investment opportunities into an initial investment plan
    - Analyze different options to arrive at a prioritized plan for review

5. Revise and approve plan:
    - Evaluate the draft plan emerging from the prioritization process
    - Pressure test proposed investments and conduct sensitivity analysis
    - Engage senior leadership to approve plan

6. Execute plan and track outcomes
    - Track execution of the plan and performance of investments using defined metrics
    - Leverage performance data to improve the planning process and future plans

7. Oversee and govern process:
    - Organize the investment planning process and dedicate resources to its execution
    - Outline roles, responsibilities, and accountability related to the planning process
    - Create appropriate documentation for policies and processes

After outlining a framework for evaluation, we developed “rubrics” that defined the characteristics of a spectrum of maturity for each capability on a scale from 1 to 5. A score of 1 on a rubric is defined as poor performance on the capability. Scores of 1 would be expected in very poorly performing organizations with weak or non-existent planning processes and governance. A score of 3 is consistent with an average or typical utility approach on a given capability. A score of 3 indicates that performance meets expectations on a given capability, and a utility scoring 3s on each step would not have any major deficiencies that would prevent it from developing an appropriate investment plan. A 5 is defined as truly excellent or innovative performance on the capability. We would expect few organizations to score 5s across all capabilities given the volume of capabilities required to execute a planning process and the complexity involved.

In evaluating Hydro One, we included an asterisk next to some scores. The capabilities scored with an asterisk fell into two categories:

- Capabilities where specific circumstances have impacted Hydro One's planning process in 2017 that are not expected to persist (e.g. process steps compressed due to the pace of recent rate filings).
- Capabilities where Hydro One has a documented plan in place to continue to improve on the capability in question, and where we would expect an upward trajectory to the score in the future.

We included the asterisk to acknowledge that Hydro One's planning process continues to evolve, while recognizing that we are primarily evaluating the plan developed in 2017 to support Hydro One's 2019-2023 Transmission rate filing.

To assess the planning process, we gathered information about Hydro One's practices through its regulatory filings, interviews and internal document reviews. We conducted multiple rounds of interviews with members of Hydro One's planning team to understand the details of the planning process and to understand how key elements described in documents were carried out in practice. We also reviewed documents shared by Hydro One that provided additional detail on how the investment planning process was conducted and how it has recently changed. We attempted, wherever possible, to obtain objective or quantitative support for assertions with significant potential for subjectivity.

Finally, we highlighted the areas where Hydro One is expected to continue to mature and provided recommendations for how Hydro One can further its progress towards best in class planning.

IV. Assessment of Hydro One's planning process for the 2019-2023 Transmission System Plan

Overall, Hydro One has significantly improved its capabilities in investment planning since its last Transmission filing. Hydro One's performance is in line with what we see from typical peer utility planning processes on all capabilities, and performs at a level consistent with what we have observed at leading utilities in a number of areas.

For those areas where Hydro One's process remains less mature than best in class peers, Hydro One has acknowledged these gaps; has plans in place to improve upon these capabilities; and shared the details of those plans as we were evaluating the process. These plans include continuing to strengthen its data coverage for key assets, ensuring asset strategies are updated, relevant and in place ahead of future planning cycles, and continuing to refine how Hydro One estimates and tracks the outcomes that the investment plan delivers.

We have summarized our assessment of Hydro One's performance relative to our selected leading peer set in Exhibit 1, referenced in the executive summary.

The detailed results of our assessment for each element of the planning process are included in the following sections 1-7, aligned to the 7 process steps in Exhibit 2.

1. Assessment of Hydro One's capabilities in defining plan objectives and constraints:

The critical first step in a planning process is to define strategic objectives and identify initial budget constraints to guide the subsequent development of the plan. This includes several activities:

- Translating corporate strategic objectives into investment planning objectives
- Ensuring customer, regulatory, and stakeholder perspectives are included in defining objectives
- Identifying financial envelope constraints based on strategic, financial and rate impact considerations

Below we outline the spectrum of maturity that we have observed across this capability. In exceptional planning processes that would score a 5, planning is guided by a comprehensive corporate strategy that is informed by customer and regulatory perspectives. The corporate strategy is translated into outcomes that a plan is expected to achieve. Capital and OM&A budgets are subsequently defined strategically, based on operational, financial, regulatory and customer considerations. Finally, capital and OM&A budgets are set to define the level of funding the company believes is necessary to meet its objectives, and the scope of the process and the budgets included are clarified to all stakeholders in the organization.

In a typical utility process, we would expect to see a high-level definition of corporate strategy and objectives that may be less specific than those defined in a truly “best in class” process. We would expect an incorporation of regulatory and customer perspectives, but perhaps not well documented or primarily focused on minimum regulatory compliance and customer satisfaction. A typical planning process includes clear definitions of budgets to guide subsequent planning, but the budgets may not incorporate benchmarking or strategic input to help substantiate spending levels.

In a poorly executed planning process, we would expect a loosely defined scope and budget that leaves high potential for “rogue” spending outside of the plan. We would also expect limited strategic input into the plan and weak alignment to regulatory and customer expectations.

We have defined the specific capabilities related to this process step and the spectrum of maturity for each in Exhibit 4 below.

1

Exhibit 4: Rubric: Define investment plan objectives and constraints

Budget definition and strategic input

Process by which a company:
- Incorporates corporate and operations strategy into investment plan
- Incorporates customer and regulatory perspectives into plan development
- Defines financial envelopes and other key constraints for planning process

Capability	Characteristics of "1"	Characteristics of "3"	Characteristics of "5"	Benchmark for "5"
Scope of investment planning process defined & articulated	• No clear scope for LOBs and types of spend included in IPP • Substantial rogue spend	• Scope understood; not fully codified • Some codification but confusion over scope; some "rogue" spend	• Scope of IPP and budgets involved widely understood	• ISO
Organizational strategy and objectives defined to guide plan	• No clear objectives or outcomes defined • No defined corporate strategy to inform investments	• Objectives and outcomes defined at high level to guide plan	• Strategy translates to quantified, outcome-driven objectives • Objectives clearly communicated ahead of IPP	• ISO
Strategy and objectives shaped by company, regulatory and customer perspectives	• Objectives reflect internal company perspectives only	• Some inclusion of customer and regulatory perspectives • Primarily focused on customer satisfaction and minimum compliance	• Robust incorporation of all key stakeholder perspectives, including desired customer outcomes, in strategy and objectives	• Industry best practice (IBP)
Budget and other constraints identified & communicated	• Corp. boundary constraints not communicated by leadership	• Timely communication of boundary conditions • Rough financial guidelines shared	• Early, clear communication of strategically-defined constraints	• IBP

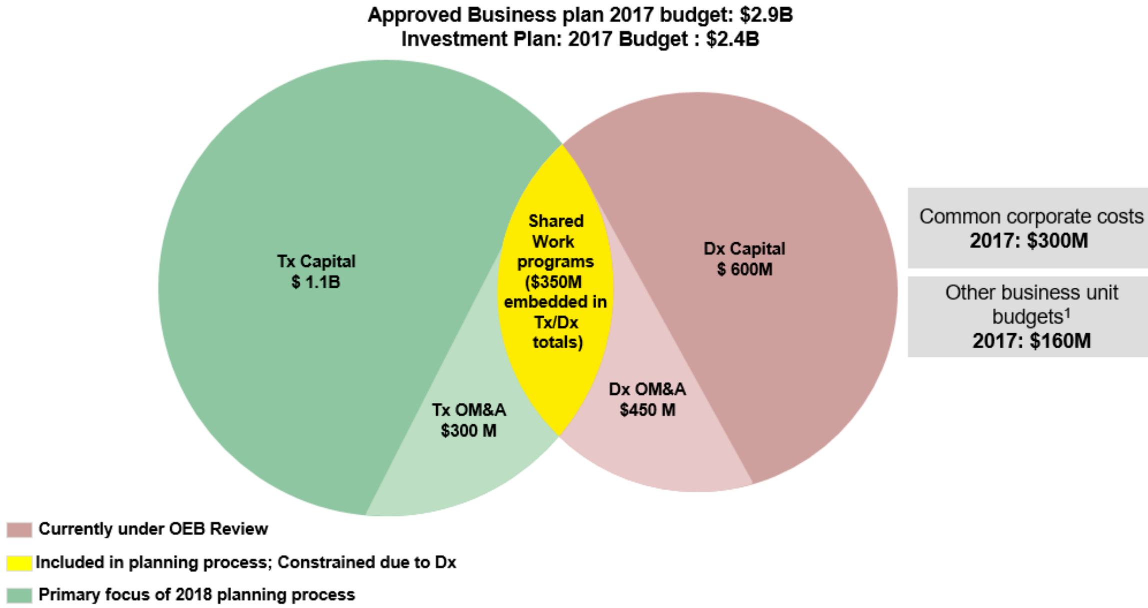
Hydro One's performance on this capability significantly exceeds what we would expect from a typical utility planning process. As a result, we scored Hydro One as a 4.3/5 on this dimension overall. In the areas where Hydro One can continue to progress towards best in class performance, Hydro One has improvement plans in place, and thus we would expect to see continued improvement in the future. Details of our assessment of Hydro One's performance on specific capabilities within this step are included in Exhibit 5.

❶ Exhibit 5: Maturity Assessment: Define investment plan objectives and constraints

Capability	1 – 3 – 5	Comments on score
Scope of investment planning process defined & articulated	4*	• Scope of process defined for operating groups and communicated • Acknowledged some minor potential for "gray areas" in common vs. work program spend • Addressing with additional education
Organizational strategy and objectives defined to guide plan	4	• Objectives defined at high level in corp. priorities • More specific objectives and outcomes communicated in corporate and operations strategy documents
Strategy and objectives shaped by company, regulatory and customer perspectives	5	• Strategy and objectives documents reflect internal company perspectives along with desired customer and regulatory outcomes • Exceed level of stakeholder input included in most utility planning objectives
Budget and other constraints identified & communicated	4*	• Budget defined in 2017 based on historical levels consistent with as-filed plan, where increases in capital were defined more strategically; filing cadence not expected to persist, enabling future budget discussions to be defined more strategically • Budget lines were widely communicated and initial budget shared with ELT and Tx filing SteerCo ahead of plan formulation

A key foundation for a planning process is defining a clear scope for the types of spending that are relevant to the plan. In 2017, Hydro One outlined clear definitions around the lines of business and types of project and program spending that are included in the investment planning process. At the same time, Hydro One notified relevant stakeholders of the timing of the process and their roles and responsibilities with respect to investment planning. One of the ways Hydro One described the scope of the 2017 process to stakeholders is included as Exhibit 6. This exhibit lays out the scope of the 2017 planning process in the context of Hydro One's overall budget, and the ongoing litigation for Hydro One's Distribution application.

Exhibit 6: Definition of Scope for 2017 Planning Process



1. Include B2M, GLP, Additional LDCs and telecom.
Source: 2017 Tx and Dx Business plans; Consolidated business plan. Totals are rounded

Hydro One also has more specific definitions for key categories of spending in the investment plan that help to clarify the scope. Hydro One has clear guidelines for program vs. project spending that are used to define differences between the two. Hydro One also has a well-defined formula for allocating overhead costs to different categories within the investment plan. Hydro One has acknowledged that there remains some room for improvement in fully articulating the scope of the plan, particularly for new types of spending that may straddle two categories, such as customer work program vs. customer common cost budgets. This gray area exists for relatively narrow categories of spending, and does not undermine performance on this capability. Hydro One plans to continue to use annual planning kick-off sessions to educate participants on the scope of the plan to mitigate the potential for gray areas to emerge.

A second key capability in defining objectives and constraints is outlining strategic objectives. Hydro One was guided by several strategy documents as it began the 2017 planning process.

Initially, Hydro One's CEO shared a list of 2017 Corporate Priorities in March 2017. This document, shared below as Exhibit 7, included high-level priorities for the year.

Exhibit 7: Hydro One 2017 Corporate Priorities

Priority	**Description**
Health and Safety	Safety is our number one priority, and as such, we will continue on our path to achieve world-class health and safety performance by creating an injury free workplace and maintaining public safety
Customer	We will put our customers first by listening and responding to their needs, advocating on their behalf, and focusing the organization on pursuing activities that have both meaning and impact
Work Programs	We will pursue continuous innovation in our work programs through building and maintaining reliable and affordable power supply as well as transmission and distribution systems
Net Income	We will maximize net earnings and increase shareholder value without compromising work program delivery through shared commitment to reduce costs and complete work more efficiently
Productivity	We will successfully implement initiatives across the organization which will improve productivity and generate significant cost savings
People	Our primary strength is the capability of our people. We will continue to build a culture of accountability and trust and are committed to delivering programs that enable greater engagement of all employees

In April 2017, Hydro One's board approved a set of strategic objectives that added additional detail to some of Hydro One's initial corporate priorities and introduced several new strategic objectives for the organization for the next five years. A summary of Hydro One's strategic objectives is included in Exhibit 8.

Exhibit 8: Strategic Objectives

Strategic pillar	Associated objectives
Optimize the core	• Achieve and maintain world-class safety performance • Maintain top tier/quartile transmission reliability performance • Achieve a step change improvement in distribution reliability • Engage in being recognized as a top employer • Be a leading employer for diversity and inclusion • Establish trusted partnerships with First Nations and Métis • Lead the consolidation of Ontario LDCs • Establish a trusted brand with strong customer loyalty • Proactively influence energy policy and regulation to appropriately incentivize modernization of the electricity system
Bring Innovation to the core	• Become known as a leading innovation company • Build and employ culture of change and innovation
Diversify via commercial business	• Lead the market in the commercial businesses we enter
Build scale through acquisition	• Pursue and close acquisitions that align with our strategy and are accretive to our earnings

Hydro One's corporate strategy added specific objectives to Hydro One's previously-defined priorities, and was subsequently translated into priorities and objectives for Hydro One's operating divisions. In May of 2017, Hydro One's Operations group, which encompasses its Transmission and Distribution operations, defined its objectives and goals for 2020. These objectives reflected the overall corporate strategy and identified targets for qualitative and quantitative outcomes, and are included in Exhibit 9. The combination of these documents provided a robust set of objectives for the organization as it developed the investment plan.

Exhibit 9: Operations 2020 goals

Vision	Metric	2016 levels	2020 Goal
Be an industry leader in **Safety & Environment** for our employees contractors, and the public	Recordable incidents per 200k hrs- Ops	1.2 (82 incidents)	**20% improvement vs. 2016** 0.95 (65 incidents)
	High MRPHs per 200k hrs- Ops	0.35 (24 incidents)	**20% improvement vs. 2016** 0.27 (19 incidents)
	Preventable MVAs per 200k hrs- Ops	1.7 (117 incidents)	**15% improvement vs. 2016** 1.4 (99 incidents)
Deliver improved **Reliability** to our customers, incorporating their input and priorities	Tx SAIDI-mc Duration (minutes)	3.9 (5 yr avg: 9.5)	**Maintain top quartile/tier performance** through continuous improvement, with a focus on the largest outage contributors today
	Tx SAIDI-mc Frequency (#interruptions)	0.25 (5 yr avg: 0.24)	
	Dx SAIDI Duration (minutes)	7.8 (5 yr avg: 7.3)	Achieve a **step change improvement** within our existing resource envelope by changing the way we plan and execute work across the province
	Dx SAIFI Frequency (#interruptions)	2.50 (5 yr avg: 2.6)	
Provide **Cost effective** service to our customers by improving our productivity	Tx Ops O&M	$7700/km[1]	**Productivity improvement in everything we do,** with resources allocated to areas that benefits our customers most
	Dx Ops O&M	$2600/km[1]	
Always be there for our **Customers** with a seamless experience in all operations interactions	Tx customer commitments mets (%)	85%[2]	**15%. Improvement vs. 2017 level** 98%
	New residential/small business customers connected on time (%)	98.6%	**Continuous improvement** 99.0%
	Scheduled appointment met on time (%)	99.5%	**Continuous improvement** 99.7%

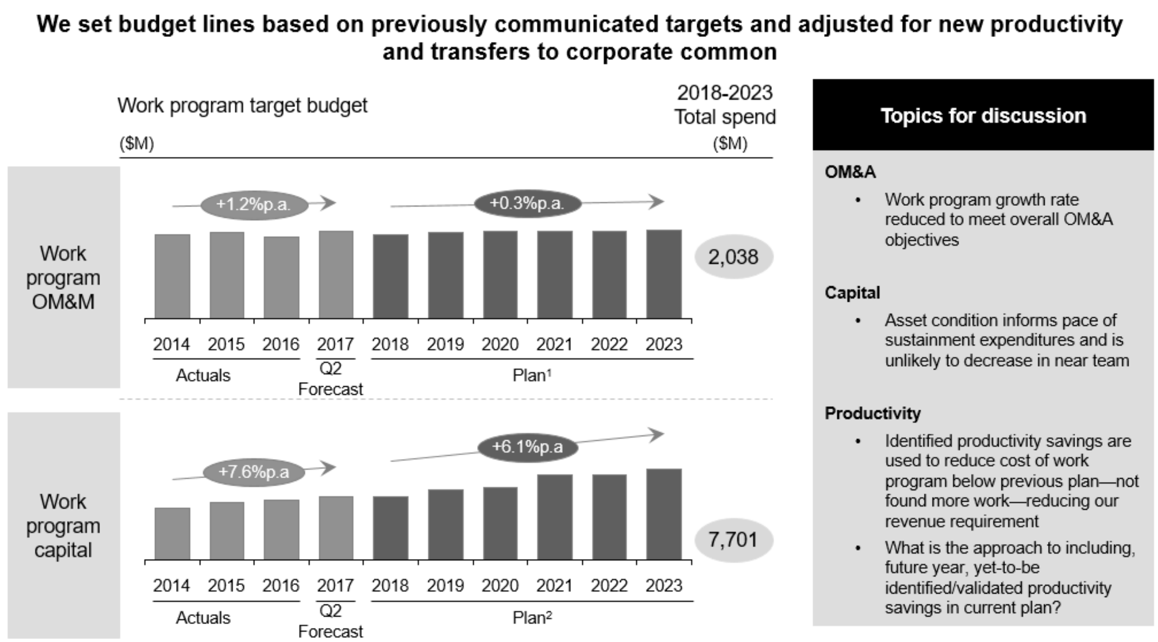
Note: (1) 2015 results: (2) Metric established in established in Q2 2017 – 85% is the 2017 goal based on estimated current performance privileged and confidential- internal use only

In some utility planning processes we have observed, strategic objectives at this stage in the process would be translated into performance goals for the planning period, measured by metrics. These metric targets would be used to guide budget development, investment option development, and subsequent prioritization. However, other utilities take a risk-based approach to planning, and then translate the risk mitigation potential of the prioritized plan into expected plan outcomes, such as reliability, safety or productivity improvement. Both approaches are valid, and each has been deployed successfully in different utilities. Hydro One's planning approach is heavily focused on risk mitigation, which helps guide how the team evaluates different investment options, ranks them in terms of priority, and assesses different marginal investment options when reviewing the plan. In this approach, performance targets are calculated based on expected results of a prioritized plan and shared as 5 year targets in Hydro One's scorecard, but are not explicitly articulated as part of the initial development of strategic inputs.

Another best practice on this dimension is to include stakeholder perspectives in defining plan objectives. This includes regulator and customer perspectives, along with other key considerations such as relevant public policies and Indigenous concerns. Given that the expectations around the consideration of stakeholder, and specifically customer perspectives, in planning in Ontario are higher than in many other jurisdictions, Hydro One's performance on this capability exceeds that of many other utilities. In other utilities we have observed, consideration of customer and regulatory perspectives is often limited to customer satisfaction and rate impact considerations in developing strategic objectives, whereas Hydro One conducted a detailed customer engagement process focused on understanding the outcomes valued by customers and providing them with scenarios to evaluate that helped inform the overall investment plan. We are not in a position to opine on whether Hydro One met the OEB's expectations for its customer engagement, but the existence of the customer engagement process puts Hydro One ahead of many utilities in its incorporation of Transmission customer perspectives into its plan. Hydro One's objectives also reflect key regulatory and public policy considerations through their reference to public safety, environmental policy, and engagement with Indigenous communities.

In addition to defining strategic objectives, another key component at the onset of a planning process involves defining relevant budget constraints for the plan. Hydro One defined and communicated an initial Transmission capital and OM&A budget at the beginning of its planning process in May of 2017. Hydro One relied on the capital levels it had previously filed with the OEB in its 2017-2018 filing and extended the trajectory of the capital plan included in that filing by 2 years to 2023. Hydro One defined its work program OM&A budget by relying on previously filed levels and adjusting for increased productivity initiatives that had been identified since its last filing. The budgets were included in initial updates to the planning teams and Hydro One's leadership; an example of content from the budget-definition discussion is included as Exhibit 10.

Exhibit 10: Summary of Budget-Setting Discussion



1. Plan over reduced by ~$6M/year transfer to corporate common and ~$1M/year in newly identified productivity savings from baseline based 2018-2022 based on previous business plan. 2023 assumed to grow at 2018-2022 CAGR 2. Plan over reduced by ~$10M/year transfer to corporate common and ~$18-25M/year in newly identified productivity savings from baseline based 2018-2022 based on previous business plan. 2023 assumed to grow at 2018-2022 CAGR

Hydro One has explained that they relied on their previously filed plan to define the capital and OM&A budgets to remain consistent with the plan under OEB review in the 2017-2018 filing until September 2017. Hydro One then revised the budget for 2019-2023 after receiving the OEB's decision. The initial five year plan was informed by Hydro One's legacy strategic objectives, its assessments of system needs and its view of the capital and OM&A levels required in order to maintain Transmission system reliability. Hydro One's 2019-2023 budget reflects many of the same objectives and continues a trajectory of capital and OM&A spending similar to its filed plan.

While relying on historical levels is not fully in line with best-in-class utility planning, where budgets are defined strategically based on financial, customer and operational concerns, we recognize that Hydro One's 2017 budget setting process was defined by uncertainty around the results of its last filing, and that these circumstances are not expected to continue in future years as Hydro One transitions to longer filing terms. In addition, we recognize that Hydro One did not rigidly adhere to its historical levels; rather there was sufficient time and flexibility in the planning period to change the budget as new information emerged.

2. Assessment of Hydro One's capabilities in developing investment plan options:

After identifying a budget and other constraints, the next step in the planning process is to develop investment options for potential inclusion in the plan. This step includes several key activities:

- Leveraging asset data to develop a set of preferred investment candidates aligned to specific asset strategies
- Using cost and benchmarking data to form estimates of project cost
- Enabling choice through the development of reasonable alternatives to the preferred investment candidates

We have observed a broad spectrum of maturity in the capabilities relevant to this step of the planning process. Best-in-class planning processes are distinguished by their development of rigorous asset strategies that guide investments, and incorporation of a data-driven methodology for investment development. While most utilities strive to have condition data that is as comprehensive as possible, many utilities we consulted face challenges with data collection given the age of their Transmission assets. As a result, few utilities reach 100% condition data collection on major assets. The best utilities, however, have fewer gaps vs. peers, which they mitigate with sound planner judgment when data is unavailable. Leaders in this capability also stand out for having thorough, accurate project cost estimates. Cost estimates, informed by internal and external benchmarking, should be more detailed for the initial 24 months of the plan. Finally, best-in-class planning processes deliver sufficient volume of investment candidates to enable rigorous prioritization.

Processes that are consistent with average performance tend to have many of the same features, but may be less comprehensive than best-in-class practices in terms of data availability or thoroughness of analysis. We would expect these processes to employ asset condition and demographic data to develop investment options through a formalized approach, but testing data may be less comprehensive, or their assessment of opportunities to aggregate work may be less quantitatively rigorous. Their project cost estimations may be detailed for only the first 12 months of the plan, or they may be informed only by internal data sources, with no external benchmarking conducted.

Poor processes are marked by simplistic or non-existent asset strategies, including a reliance on asset age as the primary data point for repair or replacement, a lack of a systematic approach to evaluating alternatives or batching work, and incomplete or low quality cost data and project estimates, even for the initial years of the plan.

We have defined the specific capabilities related to this process step and the spectrum of maturity for each in the scoring rubric for "Develop Investment Plan Options," included as Exhibit 11.

2

Exhibit 11: Rubric: Develop investment plan options (I/II)

Development of investment inputs

Process by which a company:
- Develops candidate investments informed by condition data
- Develops alternatives to preferred investments

Capability	Characteristics of "1"	Characteristics of "3"	Characteristics of "5"	Benchmark for "5"
Asset management strategies (outlining guidelines for key asset replacement/repair) defined, communicated, complied with	• No documented asset management strategies	• Asset management strategy documented, but not regularly updated/readily available for use • Asset management strategies define EOL in terms of time, not usage • Asset condition dashboards are generally populated with data collected from inspections of assets, but may be stale • Proposed investments largely aligned to strategies, with some "grey areas"	• Asset management strategy is documented, regularly updated, and easily accessible • Asset management strategies define EOL in terms of usage/condition • Asset condition dashboards are populated with real-time condition data • Clear link between AM strategy and proposed or executed investments	• IBP • ISO
Investment candidate development driven by data inputs, including condition	• Data, (e.g. condition, loading) not used in meaningful way to determine investment candidates	• Data used to identify need for some investment candidates, but process not standardized and qualitative drivers relied upon	• Standardized process in which condition data is used to identify substantially all investment candidates	• IBP
Project costs informed by unit-based data	• No unit-based measures used	• Unit-based measures calculated only for highly standardized tasks (i.e. those completed >100x/year) • Estimates based on internal data only	• Unit-based measures calculated for all repeated activities (i.e. those completed > 20x/year) • Estimates based on internal data and external benchmarking	• IBP

2

Exhibit 11: Rubric: Develop investment plan options (II/II)

Development of investment inputs

Process by which a company:
- Develops candidate investments informed by condition data
- Develops alternatives to preferred investments

Capability	Characteristics of "1"	Characteristics of "3"	Characteristics of "5"	Benchmark for "5"
Detailed estimates included for initial plan time frame	• High-level estimates included in plan for 5 years and insufficient detail for early years of spending	• Detailed estimates for initial 6-12 mos of work • High-level estimates included for remaining years of plan	• Detailed estimates for initial 18-24 mos.+ of work • High-level estimates included for remaining years of plan	• IBP
Universe of candidate investments sufficient to enable rigorous prioritization	• Incomplete universe of candidate investments • Candidate investment development influenced by premature views of prioritization/optimization results	• All candidate investments developed but unequal rigor in development guided by expected outcomes of prioritization (e.g. only develop estimates for high likelihood projects)	• All candidate investments developed, with differences in rigor based on investment size • Sum of all potential investments exceeds budget by at least 10%	• IBP
Alternatives to identified investments considered	• Investments developed as standalone candidates – no alternatives	• Alternatives (i.e., OM&A vs. capital, capital vs. capital alternatives) considered for major investment candidates	• Alternatives (i.e., OM&A vs. capital, capital vs. capital , conservation alternatives) considered for all major investment projects • Systematic approach to alternative development	• IBP
Operational benefits of batching work considered	• No consideration of how batching by location or asset type would impact overall cost or ability to complete work	• Benefits (e.g. savings, outage availability) of batching considered as part of planner evaluation, but not quantified	• Potential operational benefits of batching quantified and reflected in prioritization and selection • Only components with compelling value case (incl. economics, outage efficiency) for batching included in projects	• IBP

Hydro One's performance on this capability exceeds what we would expect from an average or typical utility planning process; we rate Hydro One at 3.9/5 overall on this capability. There are some key areas where Hydro One can continue to mature, notably continuing to develop investment options informed by data from condition testing and the asset analytics system, and ensuring relevant asset strategies are in place in time to guide future planning cycles. Details on Hydro One's performance on specific capabilities within this step are included in Exhibit 12.

2

Exhibit 12: Maturity Assessment: Develop investment plan options

Capability	Score (1 – 3 – 5)	Comments on score
Asset mgmt. strategies (outlining guidelines for key asset replacement/repair) defined, communicated, complied with	3*	• Strategies overhauled to increase rigor, but developed in parallel to IPP • Will be in place for future filings
Investment candidate development driven by data inputs, including condition	3*	• Condition data used to develop candidates • Backlog in data collection means data does not exist for all end-of-life assets, but working to address
Project costs informed by unit cost data	4	• Unit cost catalog used to inform estimates • Benchmarking for some capital programs (e.g. insulators) but not widespread
Detailed estimates included for initial plan time frame	4*	• Budgetary estimates for ~90% of plan for first year, ~80% of plan for 12-24 mos., • Efforts in place to increase estimation rigor
Universe of candidate investments sufficient to enable rigorous prioritization	5	• Sufficient volume of candidate investments to enable prioritization (Universe >10% vs. final budget) • Larger candidates developed in more detail
Alternatives to identified investments considered	4	• Viable alternatives considered for majority of investments where possible (i.e. stations) • Alternatives defined in general (i.e., repair vs. replace) and specific terms • Comparison of alternatives at times qualitative; when quant analysis is done focuses on differences in costs vs. outcomes
Operational efficiencies of batching work considered	4	• Rules outlined that govern batching decisions to introduce rigor into decisions and discourage pre-investment • Potential to add more quantitative rigor to support individual batching decisions

In the ISO 55000 asset management standards, asset strategies form a critical foundation for decision making around key utility assets. Hydro One has historically had asset management strategies in place to guide its planning process. Recently, Hydro One has undertaken an effort to strengthen its asset management strategies by updating them to reflect the latest operations strategy and most recent data, and harmonizing their format to ensure consistency across asset types.

The content of Hydro One's asset strategies is thorough and relevant to the planning process. They include information on the operational asset model (e.g., expected service life), fleet condition, historical investment levels, and capex and OM&A strategies (e.g. criteria for evaluating maintain vs. replace trade-offs). Hydro One's recent effort to update strategies represents progress towards the ISO standard and best practice of having updated, relevant, detailed asset strategies. However, not all of its updated strategies were in place to guide 2019-2023 plan as they were developed in parallel to the 2017 planning cycle. With its legacy asset strategies, Hydro One planners had access to strategy documents that helped guide the development of investment options. Given continuity in its asset strategies, the final plan largely aligned to the content of the revised asset strategies now in place.

Another key component of strong utility planning is grounding investment option development in data to ensure that the projects being developed address the most significant risks on the system. Condition and system data should also help inform the evaluation of investment alternatives before arriving at a preferred investment option.

Hydro One deploys a data-driven process for identifying potential investment projects, though detailed condition data is not yet fully available for all major assets. Hydro One collects data on age, condition (based on testing), demographics, historical maintenance costs and historical performance of assets on an ongoing basis, with information captured and shared in its asset analytics system. To assess condition, Hydro One has prioritized testing for assets reaching end of life (as defined in its asset strategies). Hydro One has acknowledged that there is a backlog in completing testing for all end of life assets due to the volume of aging transmission assets on its system. Hydro One is working to clear the backlog by enlisting additional third party resources to test certain key assets, such as conductors and insulators. We have observed that while best-in-class utility planning processes are generally informed by robust condition data that helps identify the assets requiring repair and replacement, few utilities reach 100% testing coverage on their assets given the age and geographical breadth of many transmission systems. As a result, Hydro One's performance is consistent with many typical utilities on this capability.

In developing projects, best practice is to evaluate among different types of potential options to ensure asset life cycle costs are optimized. Hydro One conducts this analysis as it is developing projects, with a focus on stations assets given the lack of maintenance or refurbishment alternatives for lines assets. Hydro One conducts a combination of qualitative and quantitative analysis to evaluate among different capital spending options and among capital and OM&A options. For transformers, NPV models are used to assess capital vs. OM&A tradeoffs, while for other types of stations assets, qualitative analysis is conducted to evaluate the risks and benefits of different capital and OM&A scenarios. Sample results of this type of analysis were provided by Hydro One, and are included below:

Exhibit 13: Sample Capital vs. OM&A Analysis for a Transformer Investment

Example 1: 500kV 750MVA Auto Transformer Repair Vs Replace.

This example demonstrates the economic assessment carried out to support a repair and delay capital replacement of a 500kV 750MVA auto transformer. This type of equipment is one of the most expensive power equipment assets within the Hydro One transmission system.

The transformer in question is a 40 year-old unit. A detailed condition assessment revealed it requires refurbishment to repair an oil leak and to mitigate a design deficiency advised by the original equipment manufacturer. These are necessary repairs to ensure safe and reliable operation of this asset. The cost for refurbishing this transformer was analyzed using the economics model described in Ex I-1-28. Details of such an analysis can be found in Ex. I-9-6, Attachment 6 - Strachan Transformer Assessment Report, Section 7- Economics.

Specific to this 500kV 750MVA auto transformer, the outcome of the economic assessment resulted in a net present value (NPV) cost of $17.2M for repair vs $18.9M for replacement. Therefore, a decision was made to proceed with repair.

Best-in-class evaluation of investment alternatives relies on quantitative analysis that enables planners to weigh risks and benefits of different options. Robust analysis focuses not only on cost but also incorporates the value of customer benefits and risks to ensure the optimal alternative is recommended for inclusion the plan. Analysis consistent with more typical utility performance on this capability focuses purely on cost to the utility to ensure the lower NPV option is selected.

Hydro One approaches investment option development by drawing on system and individual asset-level data. Planners develop potential investment projects based on an assessment of key data about assets and stations, such as system criticality, loading and outage availability. They also consider the condition of other assets at a given station where a high priority asset has been identified to develop projects, in line with Hydro One's station-centric approach. Subject matter experts focused on individual asset types (e.g. transformers, breakers, lines) help to validate projects by providing their detailed perspectives on asset condition and their understanding how aging or deteriorating assets could be addressed through different capital and OM&A alternatives. Planners incorporate this input to finalize the potential projects that will be subsequently risk scored and evaluated.

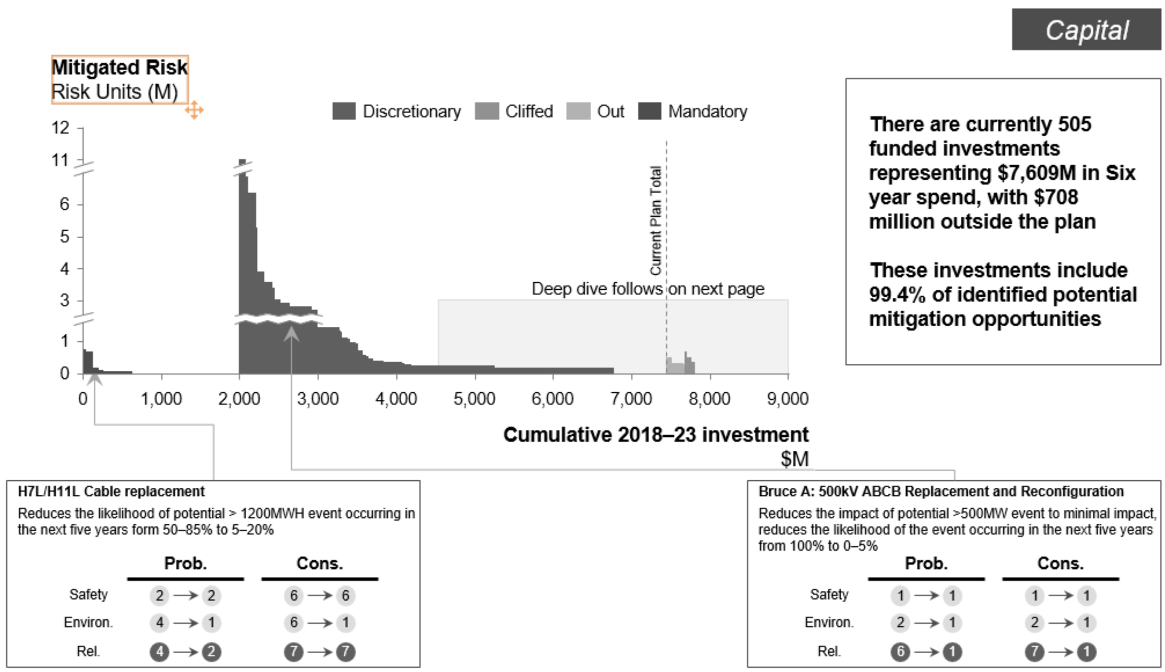
Hydro One approaches investment development by assessing system needs and analyzing asset-level data. Planners develop potential investment projects based primarily on their assessment of the condition of major power equipment (e.g. transformers, breakers), informed by data from Hydro One's asset analytics system. They also consider the condition of other assets within a given station where major equipment has been identified as needing to be replaced; this is consistent with Hydro One's integrated or station-centric planning approach. Subject matter experts focused on individual assets (e.g. transformers, breakers, lines) conduct detailed condition assessments to determine the extent of asset deterioration and conduct analysis to evaluate capital replacement or repair alternatives. This detailed input is incorporated into investment options to finalize the set of potential investments that will be subsequently risk scored and evaluated.

Hydro One's development of station projects is grounded in key guidelines that help to add rigor to its process. Hydro One planners assess whether other equipment at a station with a major asset replacement is reaching end of life within three years of planned work on the major asset. If there is, this work will be combined into a project to enable more efficient outage planning and work processes. Batching work in this way is in line with best practice for utilities given the relative difficulty of securing outages and the efficiency opportunities of dispatching crews to stations once vs. multiple times. While Hydro One's rules based approach introduces some rigor that prevents planners from "pre-investing" by requiring they consider end of life equipment only expected within 3 years of planned work, there are opportunities to further increase the level of rigor behind batching decisions by conducting quantitative analysis to ensure decisions to batch are economically efficient and support desired customer outcomes. An example of such analysis would be to compare the cost and customer impact of a batched project vs. its disaggregated parts to ensure the batching decision is correct.

Given that data input for project development comes from both subject matter experts and planners focused on developing overall projects, we would encourage continued focus on clear communication between members of the planning group, and documentation around how investments are developed to ensure investment projects are grounded in rigorous, data-driven analysis.

A key element in a rigorous planning process is ensuring that there are sufficient investments to prioritize. Less mature processes often involve developing just enough projects to fit a budget without enabling trade-offs and optimization. In best-in-class utilities, this generally means developing a universe of potential options whose value is at least 10% greater than the budget constraint. In 2017, Hydro One developed a universe of potential capital projects of $8.3 B in total spend against a final capital budget of $7.5 B, meaning the value of total investments developed exceeded the budget by more than 10%. This was in line with best practice and enabled a rigorous prioritization in subsequent steps in the process. A summary of the discussion around the size of the draft investment budget and quantity of investments falling outside the initial budget is included as Exhibit 14.

Exhibit 14: Discussion of capital budget developed for prioritization



Note: Chart is depicting 6-year spending, excludes Dx portion of common investments. Callouts are illustrative

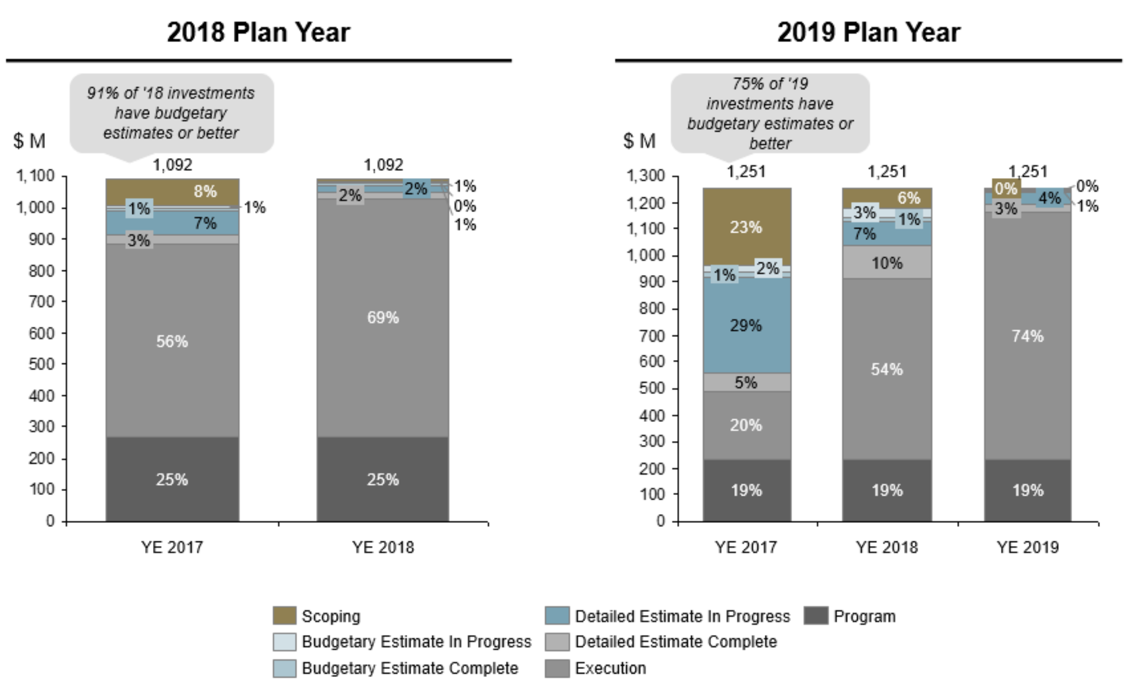
Another critical capability in developing potential investment options is evaluating estimated project costs. Hydro One's use of unit data to inform estimation and its level of estimating rigor are consistent with peer performance on these capabilities, and in some areas exceed what we expect from typical utility processes. In developing investment options, Hydro One's planners rely on a unit cost catalogue as a starting point to gauge potential costs when projects are in an initial planning phase. This catalogue is updated annually, and provides a baseline for the cost of major assets based on Hydro One's historical purchases and market conditions. Planners develop estimates with increasing levels of detail as projects are further developed, and supplement the unit cost catalogue data with actual costs as projects move closer to execution and key assets are procured.

Hydro One's internal audit (introduced into the record in Hydro One's most recent Transmission filing) identified concerns with the frequency of unit cost catalogue updates and identified gaps in ensuring the most recent catalogue was used by planners, Hydro One has worked to address these concerns through greater controls around updates to the unit cost catalogue, and increased emphasis on training. In its proposed steady state planning calendar (later included as Exhibit 27), Hydro One allocates dedicated time to updating key planning inputs, including the unit cost catalogue, before investment options are developed.

Best practice estimation for program costs relies on unit cost metrics that help ensure efficiency in executing common work programs, such as wood pole replacement or forestry. Hydro One calculates unit cost metrics as part of its productivity metric tracking on major Transmission capital and O&M programs, using the unit cost data to inform future budgeting. A best practice we have observed on program budgeting is to use internal unit cost data and external benchmarking to understand appropriate program level budgets. While Hydro One does this for some costs (e.g. Hydro One is currently conducting benchmarking for insulator replacement), there is room for additional benchmarking on other programs such as wood poles and forestry to inform productivity initiatives and ensure unit costs and overall budgets are competitive and appropriate.

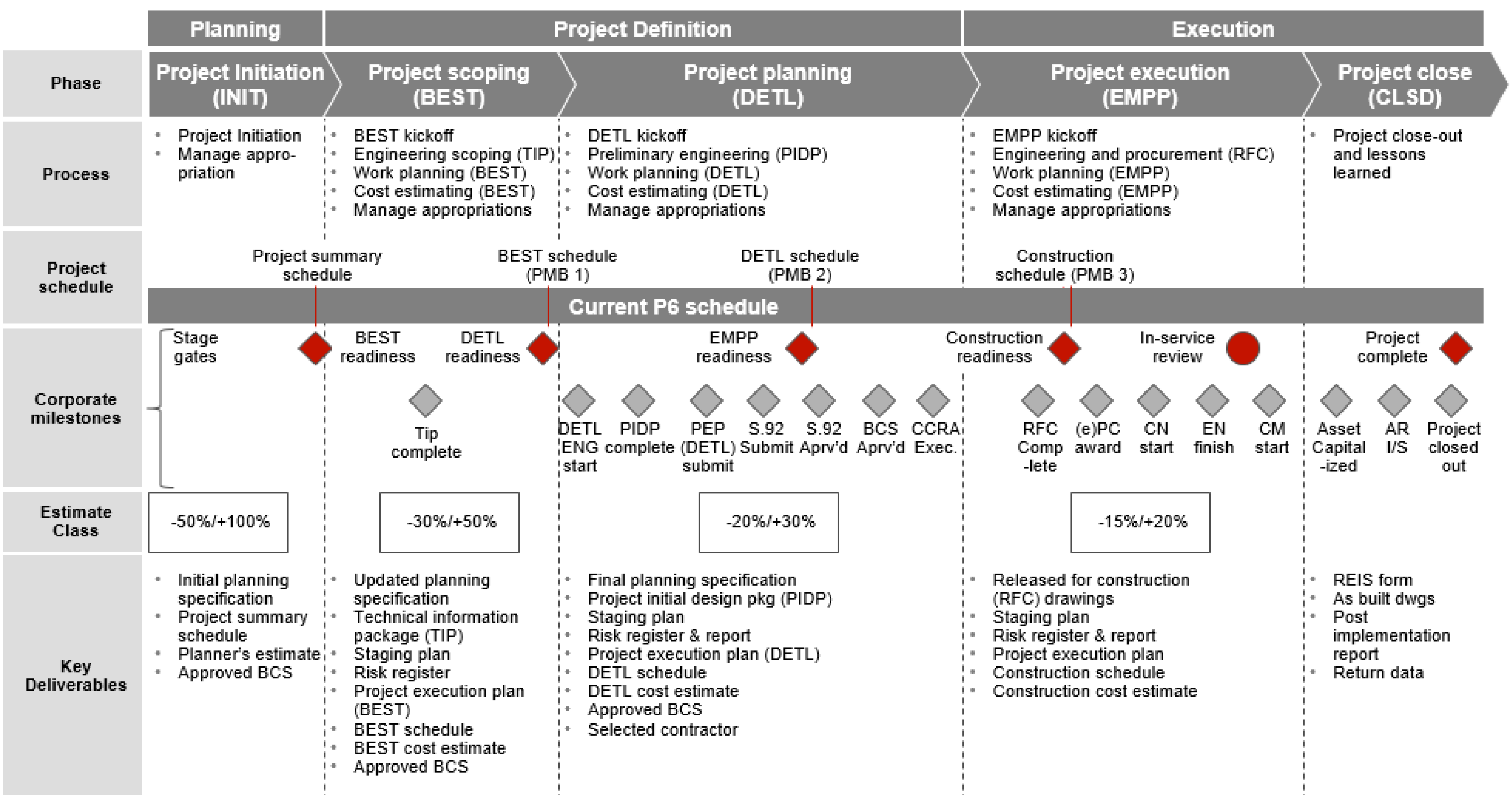
A final key capability critical to rigorous investment option development is ensuring that cost estimates that accompany potential investment options are at an appropriate level of detail. Hydro One's level of estimation detail at different stages is consistent with what we have observed as best practice. Hydro One uses detailed estimates for projects that are in execution or about to be executed and has declining levels of estimation detail as investments are farther from execution. Practically, Hydro One has a relatively high level of estimation detail for projects in the first two years of its plan, with ~80% of projects in the first two years of the plan having gone through relatively detailed estimation (budgetary or detailed estimates). Additional detail on Hydro One's level of maturity for investments in the first two years of the plan is included in the Exhibit 15.

Exhibit 15: Maturity of Hydro One capital program by year for initial two years of filing term



Hydro One has displayed relative strength on several dimensions of cost estimation, but has plans in place to continue to improve in a few key areas. For future planning cycles, Hydro One now has consistent, updated asset strategies in place to guide investment development for critical assets. Hydro One is also continuing to focus on relieving the backlog in its condition assessments for critical assets, particularly lines and insulators by enlisting third party support to conduct condition testing. Finally, Hydro One has initiatives in place to improve its estimation maturity at different project stage gates, by outlining clear expectations for the level of estimation detail and deliverables at each step in the stage gate process aligned to steps in the overall investment and business planning processes at Hydro One (detailed in Exhibit 16).

Exhibit 16: Hydro One's Transmission Capital Project Delivery Model



3. Assessment of Hydro One's capabilities in establishing criteria, scoring and calibrating investments

In this step of a planning process, potential investment options are evaluated against key criteria to enable eventual prioritization. It involves the following activities:

- Estimating the potential risk mitigation impact of investment candidates
- Calibrating risk scores to ensure consistent application across investment types

Utilities vary widely in their maturity in this step of the investment planning process. In a best-in-class process, we would expect a utility to use objective criteria to evaluate project risks and benefits. These criteria should incorporate customer and regulator concerns to ensure prioritized plans align to organizational objectives. Risk scoring should be methodological and rigorously calibrated, to increase the objectivity of the process.

In a typical investment planning process, we would still expect to clear criteria for evaluating investment options, though these criteria may be less comprehensive than in best in class utilities. Utilities performing near the middle of the peer set also had some subjectivity in the evaluation of projects and calibration of scores.

Less mature processes are characterized by their mostly subjective evaluation criteria. These processes can be ad-hoc, with no systematic evaluation criteria, and significant opportunity for gaming.

We have defined the specific capabilities related to this process step and the spectrum of maturity for each in the rubric included as Exhibit 17.

3

Exhibit 17: Rubric: Establish criteria, score and calibrate

Evaluation criteria, scoring and calibration	Process by which a company:
	• Identifies potential risks mitigated by candidate investments • Calibrates risks to ensure consistent application across investment types

Capability	Characteristics of "1"	Characteristics of "3"	Characteristics of "5"	Benchmark for "5"
Investments evaluated against risk criteria	• No methodology for evaluating risks	• Risks evaluated using standardized methodology, but scoring subjective	• Objective, quantitative risk evaluation • Risk evaluations informed by condition data	• ISO
Risk criteria incorporate customer and regulator perspectives	• Risk criteria heavily prioritize utility perspective	• Risk criteria incorporate either customer or regulator perspectives but not both	• Risk criteria incorporate both customer and regulator perspectives	• IBP
Risks calibrated consistently	• Risks evaluated by many different stakeholders, with no calibration	• Risk evaluations calibrated through discussions, with no formal methodology	• Established methodology for calibrating evaluations applied in multiple sessions	• IBP

Hydro One displays relative strength on this capability, scoring 4.3 out of 5. Additional detail on Hydro One's capabilities on this dimension is included in Exhibit 18.

In 2017, Hydro One focused on significantly improving its risk scoring capabilities, and has introduced a rigorous and transparent scoring process. Hydro One's revised risk scoring system

3

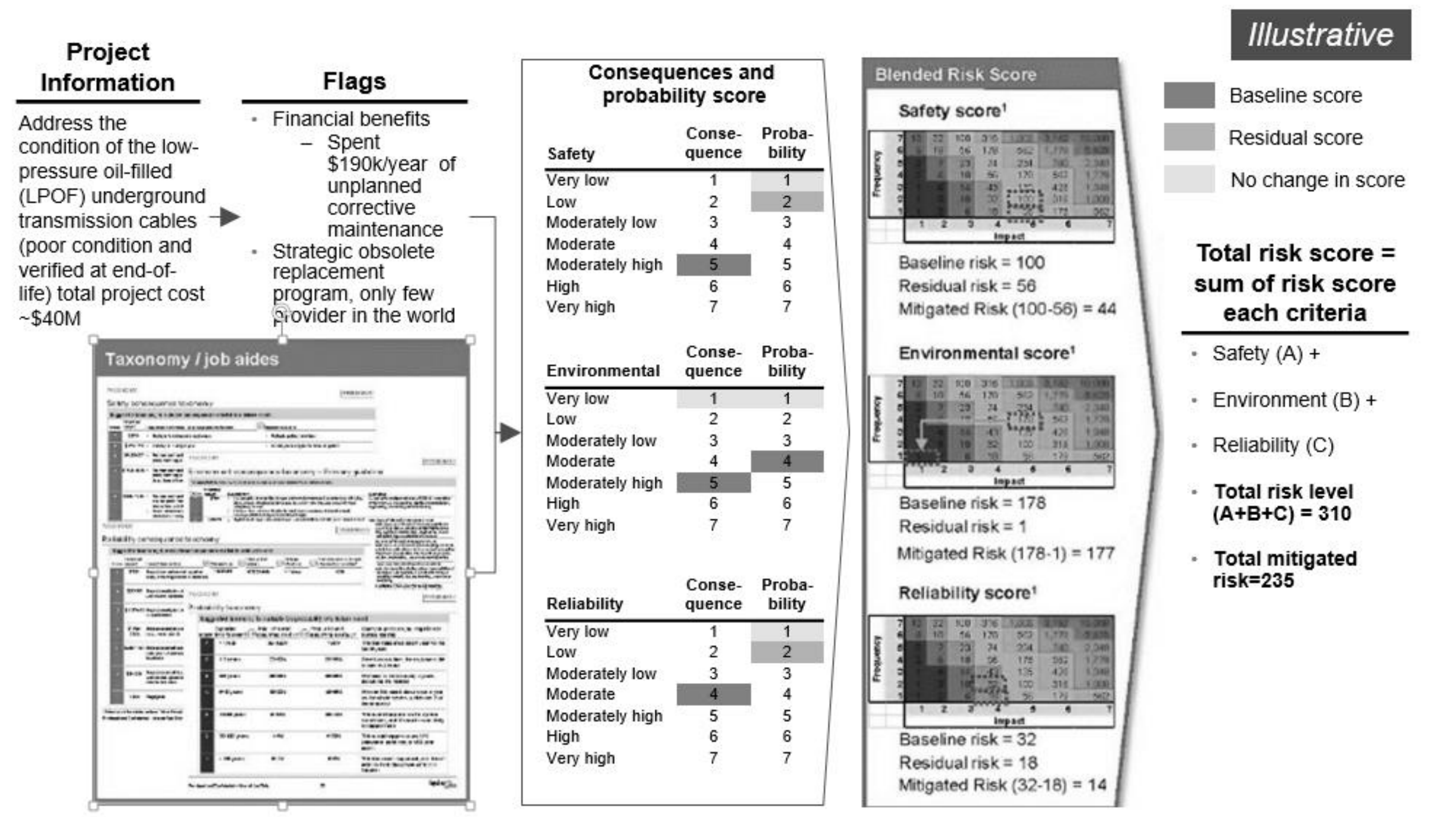
Exhibit 18: Maturity Assessment: Establish criteria, score and calibrate

Capability	1 – 3 – 5	Comments on score
Investments evaluated against risk criteria	4*	• Taxonomies were thoroughly developed and objective, but some evidence of subjectivity or inconsistency in probability and consequence calculations by planners • Opportunities to further expand use of condition data (e.g. age used for probability calculations vs. effective age) • Some identified execution concerns being addressed for future cycles with training
Risk criteria incorporate customer and regulator perspectives	5	• Evidence that customer input shaped development of taxonomies (e.g. reliability) • Flagging system allows for consideration of additional perspectives beyond risk mitigation • Customer flags incorporate customer input from ongoing engagement • Public policy flags incorporate policy considerations
Risks calibrated consistently	4*	• Multiple calibration sessions conducted with significant share of stakeholders • Self-assessment signaled potential gaps to be closed in future steady state

relies primarily on three risk taxonomies that have been developed to classify safety, environmental, and reliability risks. The taxonomies provide guidelines for planners to assess the consequence and probability of potential risks and then assess how proposed investment projects are expected to mitigate those risks. The taxonomies are fact-based, with significant analytical rigor behind the development of different levels of classification. For example, different levels of safety consequence are based on historical data of safety outcomes derived from utility industry experience. Reliability consequence information is based on realistic potential reliability outcomes, defined based on Hydro One experience and historical system data.

In evaluating investments, Hydro One planners estimate consequence and probability for two cases: a baseline case, with no investment, and a residual case, where an investment has been made and the impact of its risk reduction is estimated. Whatever risk remains is considered residual risk. The consequence and probability scores for each case are plotted on a matrix, and the difference between the two risk scores is the risk mitigation potential of the investment. These scores enable eventual prioritization of investments. The risk taxonomies are calibrated so that the risk mitigation points of each type of risk are weighted equally. Hydro One's risk evaluation approach is summarized in Exhibit 19.

Exhibit 19: Summary of Hydro One's scoring system and risk criteria



Hydro One's revised scoring system introduces new levels of additional rigor and objectivity into the risk scoring process. Best in class planning processes strive to be as objective as possible by relying heavily on quantitative data, and Hydro One has made progress toward this standard. However, we have observed that the new system still allows some room for subjectivity.

Internal documents and conversations suggest that the organization is still learning how to apply these taxonomies, and the inputs to calculating consequence and probability can remain subjective where data is not available. We have observed examples where this system was applied effectively in scoring investments; in these instances, access to condition data, hazard curves and past failure data enabled quantitative, largely objective scoring. However, this type of high-quality data does exist not for all types of assets and all types of risks, so in some cases, users applied their own judgment to assign scores.

The revised risk scoring process includes applying qualitative flags that allow consideration of other potential benefits of an investment beyond risk mitigation. Flagging allows Hydro One to make clear distinctions between mandatory investments (e.g. new connections, investments required by the regulator) and discretionary investments on the system, as well as allowing considerations like customer and productivity benefits to be included in addition to risk when assessing an investment. Hydro One introduced 4 mandatory flags, and 5 non-mandatory flags, which are described in Exhibit 20.

Exhibit 20: Types of mandatory and non-mandatory flags

Examples of mandatory flags follows

	Classification	Definition	Examples
Mandatory	Immediate/short term compliance	• Explicit obligation to a regulatory agency e.g., Ontario Energy Board (OEB) to do work within a year, with immediate risk of legal breach (Immediate) • Explicit obligation to a regulatory agency e.g., OEB with a 2–5 year risk of regulatory or legal breach (short-term)	• Upgrade systems to NERC standard (NOD)
Mandatory	Third party requests	• Explicit requests by a city, county, agency, or customer, with an 1–5 year risk of breaking the utility obligation to serve	• New ops center in Woodstock (Facilities)
Mandatory	In flight	• Under construction or 50% of total expected cost committed as of the beginning of the budget year	
Mandatory	Contractual	• Signed third party contracts for services such as IT support, call center operations, etc.	• Communication support (ISD)
Non- Mandatory	Strategic	• Codified goal by leadership team (e.g., in S-2)	• New customer portal redesign (ISD)
Non- Mandatory	Customer Engagement	• Influence of customer engagement/consultation; response to specific customer needs and preferences	
Non- Mandatory	Productivity	• Contains committed productivity savings, as tracked by corporate finance (Embedded) • Facilitates future productivity savings (Enablement)	
Non- Mandatory	Political commitments	• Explicit statement by Hydro One officer to non-agency parties such as to politicians, media or through official public statement etc.	
Non- Mandatory	Corrective or sustainment	• A risk identified by Hydro One or other utilities as a 'lesson learned' that requires near-term action • OR common sustainment pending	
Non- Mandatory	Preventative maintenance	• Opportunity to prolong asset life with planned and condition-based maintenance	
Non- Mandatory	Emergent risk	• Risk mitigation of catastrophic risk with undefined probability (outlined in common section)	

Automatically included investments should still be reviewed to identify whether scope matches the specific requirements justifying inclusion (i.e., minimum scope to meet requirement)

The use of flags helps ensure stakeholder perspectives are consistently included in evaluating investments and is a practice employed by many leading planning organizations. However, by their qualitative nature, flags introduce some subjectivity into the risk assessment process, and thus their use needs to be monitored to ensure they are not used to supersede objective risk-assessment criteria unless there is a clear justification for the investment. The calibration process helps mitigate this risk.

Hydro One's revised risk scoring method enables it to incorporate key customer and regulatory outcomes into its evaluation of projects in two ways. The first is through the definitions of consequence in the risk taxonomies, and the second is through the flagging system. Hydro One's risk taxonomies are based on key outcomes that customers and the OEB have identified as high priority. Safety consequences, can be classified in terms of harm to employees or the public. Reliability consequences can be classified in terms of unsupplied energy, load impacted and customer outage duration. Environmental consequences can be classified in terms of oil spill severity (PCB and non-PCB) and greenhouse gas emissions and the associated scale of potential impact (e.g. size of geographical area or duration of cleanup). These outcomes are reflective of customer concerns align to key regulatory and policy concerns (e.g. ensuring public safety, reducing GHG emissions). Hydro One's flags also enable it to identify investments that address key customer priorities such as improving power quality and address investments that align to strategic priorities, which include environmental and policy considerations.

As mentioned, a critical element of best in class investment planning is ensuring objectivity. The primary method Hydro One uses to ensure that taxonomies and flags are applied consistently is calibration. Hydro One conducted multiple calibration sessions that allowed for review and challenge of risk scoring for the largest proposed investments in terms of both spending and risk mitigation. The sessions allowed stakeholders to challenge how flags were applied to different investments to help reduce potential subjectivity in their application. Rigorous calibration is a hallmark of best in class planning processes, and one of the key tools used to remove subjectivity from the process in absence of perfect data. Hydro One has implemented a strong calibration process to support this goal.

While Hydro One has progressed significantly on this capability, the planning team has identified the need to continue improving the objectivity of its risk scoring, and is addressing this in future planning cycles by instituting additional training on how to apply the scoring system. This training will include showing additional case studies as examples, to ensure teams understand the risk taxonomies, the types of data used to estimate probability and consequence, and how to apply them. Hydro One has plans in place to continue to refine calibration for future cycles to ensure consistent application of risk taxonomies and flags.

4. Assessment of Hydro One's capabilities in prioritizing and selecting investments

This step encompasses the way a company develops an initial investment plan from a set of scored investment options. It involves a few key activities:

- Using defined criteria to prioritize a universe of investment candidates
- Narrowing the universe of investment candidates into an initial investment plan
- Analyzing different plan options to arrive at a recommended plan for review

A best-in-class prioritization process is based on objective criteria that allows for like comparisons, and the prioritization methodology's outcomes are well understood by stakeholders. In addition, best in class processes allow for sensitivity analysis to understand the impacts of different levels of spend and evaluate tradeoffs around a given budget.

Typical utility performance on this spectrum involves a prioritization process that is largely objective and well understood, but with some subjective assessments required due to a lack of data. Sensitivity analysis may be less rigorous than in a best in class process, or done qualitatively vs. quantitatively.

A weak utility on this spectrum would be one without a systematic prioritization process and would lack the data necessary to conduct sensitivity analysis. The outputs of its prioritization process may, as a result, be opaque and not well understood or trusted within the organization.

We have defined the specific capabilities related to this process step and the spectrum of maturity for each in Exhibit 21.

4

Exhibit 21: Rubric: Prioritize and select investments

Prioritization and selection	**Process by which a company:** • Uses defined criteria to prioritize universe of investments • Narrows the universe of investment opportunities into an initial investment plan • Analyzes different plan options to arrive at a prioritized plan for review

Capability	Characteristics of "1"	Characteristics of "3"	Characteristics of "5"	Benchmark for "5"
Investments assessed relative to each other to develop prioritized list based on decision criteria	• No clear prioritization process	• High level prioritization with some subjectivity • Some difficulty in comparing investments across types	• Full prioritization allowing for evaluation of investments on like for like basis	• IBP
Prioritization driven by risk-based methodology	• Non-risk criteria used to guide investment prioritization; risk a secondary factor	• Risk-based criteria primary driver of investment prioritization • Qualitative considerations of risk included	• Quantitative, risk-based prioritization method used	• IBP
Sensitivity analysis conducted to understand plan impact vs. cost tradeoffs	• No consideration of impact of higher/lower funding levels on risk or other outcomes	• Limited analysis around utility-focused primarily on rate impacts vs. spending levels • Limited discussion of outcomes	• Dynamic consideration of multiple levels of spending vs. rate impacts and other outcomes (e.g. risk)	• IBP
Investment selection process is understood within organization	• Process considered opaque by stakeholders within and outside of planning group • Little ability to understand or trust underlying assumptions or results	• Process understood by those directly involved with tools and assumption development, but not understood by broader stakeholder group	• Process considered transparent, with visibility into mechanics and assumptions • Results widely understood and supported	• IBP

Overall, Hydro One has improved its investment prioritization and selection process, and has introduced measures to increase transparency and objectivity into how investments are selected and traded-off. We have rated Hydro One's overall score on this dimension as 4 out of 5, exceeding the levels of performance we would expect from a typical utility planning process.

Hydro One's sub scores for investment prioritization and selection are included in Exhibit 22.

Similar to risk scoring, a key component of best-in-class prioritization processes is objectivity in evaluating investments. In Hydro One's process, investments are assessed relative to each other based on their risk mitigation potential, which has been consistently applied through its risk scoring process. In developing its plan, Hydro One first prioritizes investments that are

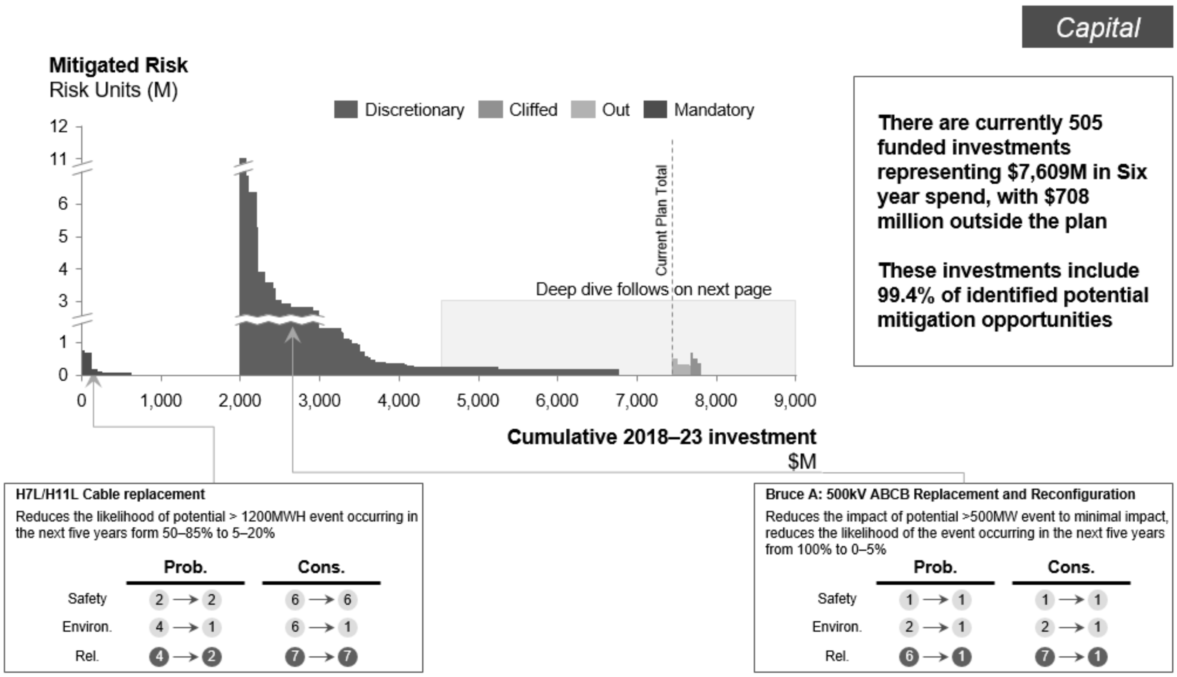
4

Exhibit 22: Maturity Assessment: Prioritize and select investments

Capability	1 3 5	Comments on score
Investments assessed relative to each other to develop prioritized list based on decision criteria	4*	• Prioritization occurs largely based on risk-scores • Segmented and prioritized for some smaller categories such as facilities, fleet, etc. • However, Power systems contained \$7.3 of \$7.8 B of spend of diverse types (e.g. reliability, innovation, telecom) – making it difficult to compare like-for-like • Efforts in place to engage in some strategic allocation for future cycles
Prioritization driven by risk-based methodology	4	• Initial prioritization driven by quantitative risk taxonomies; rank projects based on risks mitigated
Sensitivity analysis conducted to understand plan impact vs. cost tradeoffs	4*	• Understand tradeoffs made between investments at margin and from baseline to -10% scenarios using risk as outcome • Implicit consideration of rate impacts vs. explicit
Investment selection process is understood within organization	4	• Education prioritized in first year of revised process • Expect continued learning through organization as process repeated in future years

flagged as mandatory, after which it ranks investments in descending order of mitigated "risk units" that have been estimated through the application of Hydro One's taxonomies. An example of the initial output of prioritization is included as Exhibit 23.

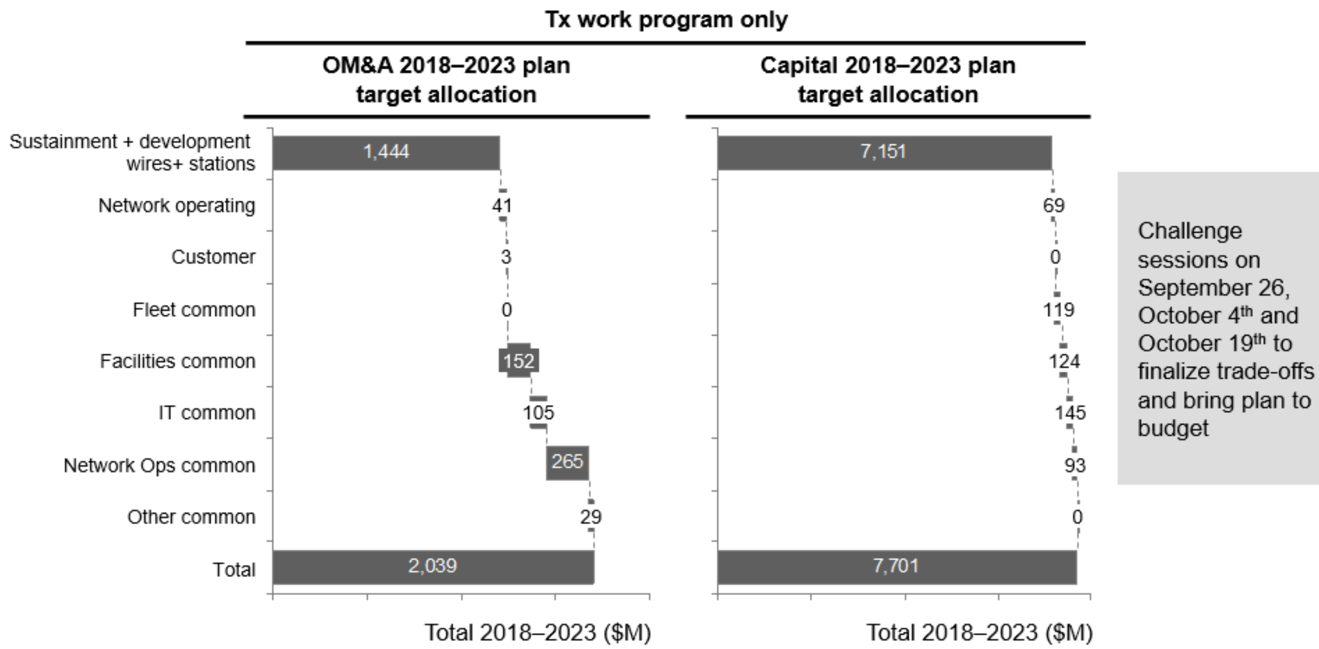
Exhibit 23: Sample output of initial prioritization based on risk



Note: Chart is depicting 6-year spending, excludes Dx portion of common investments. Callouts are illustrative

In prioritizing its draft plan, Hydro One split investments into categories to more easily compare investments (power systems, facilities, fleet, etc.). Power systems represented \$7.2B of \$7.7B in total spending prioritized in Hydro One's initial prioritization. The investments falling under power systems were diverse, including sustainment and development projects of all types (See Exhibit 24 for breakdown).

Exhibit 24: Initial breakdown of spending categories by type



Note: Allocations at group level will be updated after decision-we will maintain current budget growth assumption of 1.4% in 2023 in the interim

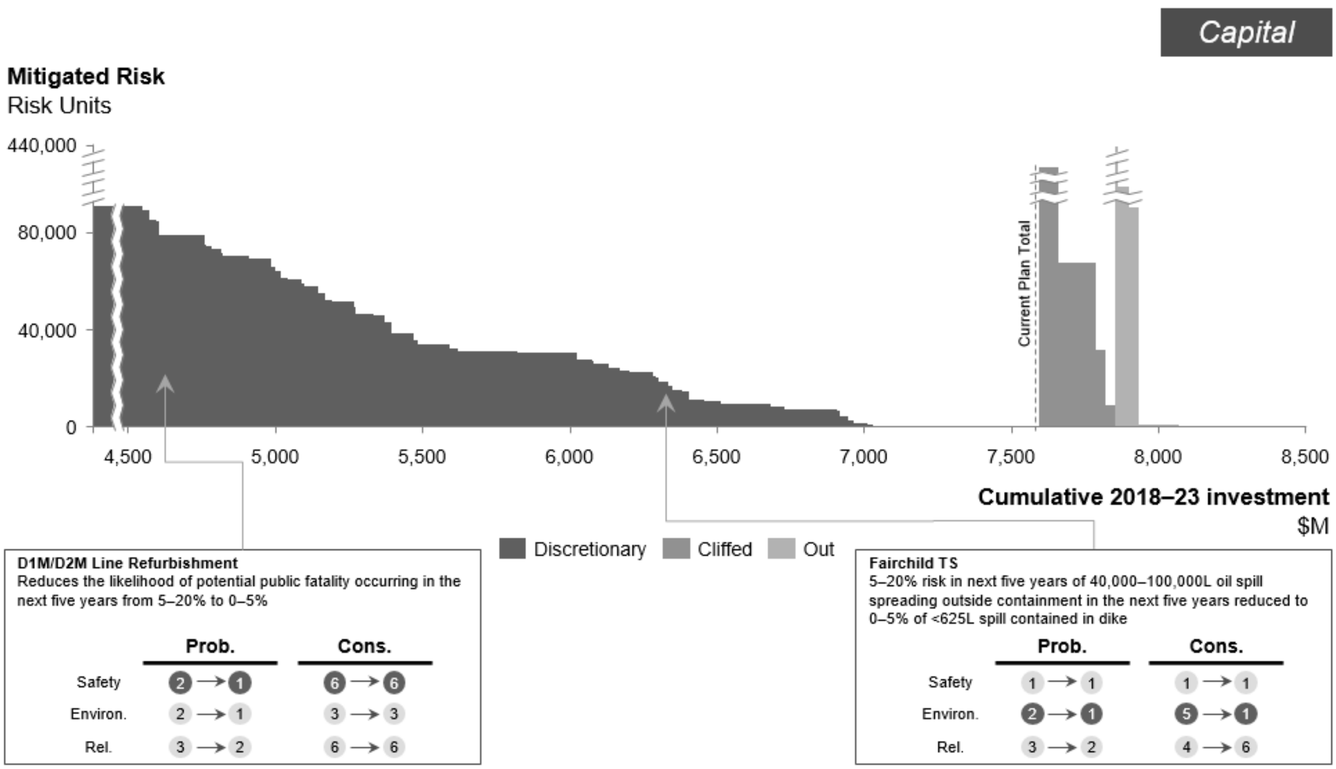
Given the large share of the power systems category, it can be difficult to compare investments "like for like" given different desired outcomes of some spending (e.g. grid modernization investments vs. reliability focused investments). While Hydro One's approach is valid and the use of standardized risk units helps mitigate this challenge, it adds some complexity to evaluating investments that Hydro One may want to consider mitigating by engaging in strategic capital allocation at the onset of future planning processes to divide the plan into smaller, discrete budgets, and then prioritizing within those budgets. This is a practice we have seen applied successfully at many leading utilities.

The qualitative flags that were used to evaluate investments in Hydro One's risk scoring process are used to identify project benefits beyond risk mitigation, and increase the consideration of some investments that may not be included in the plan on risk merits alone. The impact of discretionary flags on a project's inclusion in the plan is based on planner judgment; as a result, flagged investments can displace higher risk-mitigating investments. The role of flags introduces some subjectivity into the prioritization process, however, they also allow for consideration of non-risk benefits. The potential for subjectivity is mitigated by several factors:

- The use of clear definitions for flags so that planners understand what qualifies as a flagged investment vs. not
- The requirement for evidence to support the use of the flag
- Hydro One's rigorous calibration process that requires all flagged investments to be reviewed by the planning team to ensure comfort that the projects provide the benefits the flags describe.

Hydro One evaluated different plan scenarios to understand the impact of marginal investments on the plan and guide its ultimate prioritization. In evaluating investments at the margin, the primary metric used for spend vs. outcome trade-off was risk points vs. dollar spent (in terms of OM&A and capital – see Exhibit 25 for materials from the discussion of the risk impact of marginal investments).

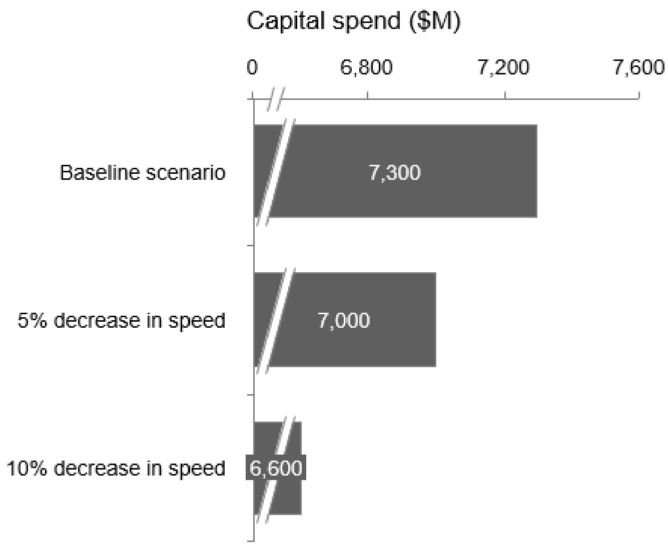
Exhibit 25: Sample from discussion of risk impact of marginal investments at challenge sessions



Note: Chart is depicting 6-year spending, excludes Dx portion of common investments. Callouts are illustrative

Hydro One reviewed three different funding levels in its initial prioritization discussion: fully funding the initial budget of $7.7 B, and two reduced scenarios that represented 5% and 10% reductions in capital and OM&A. Additional detail on these scenarios is shared in Exhibit 26.

Exhibit 26: Sample details of projects eliminated in 5% and 10% reduction scenarios



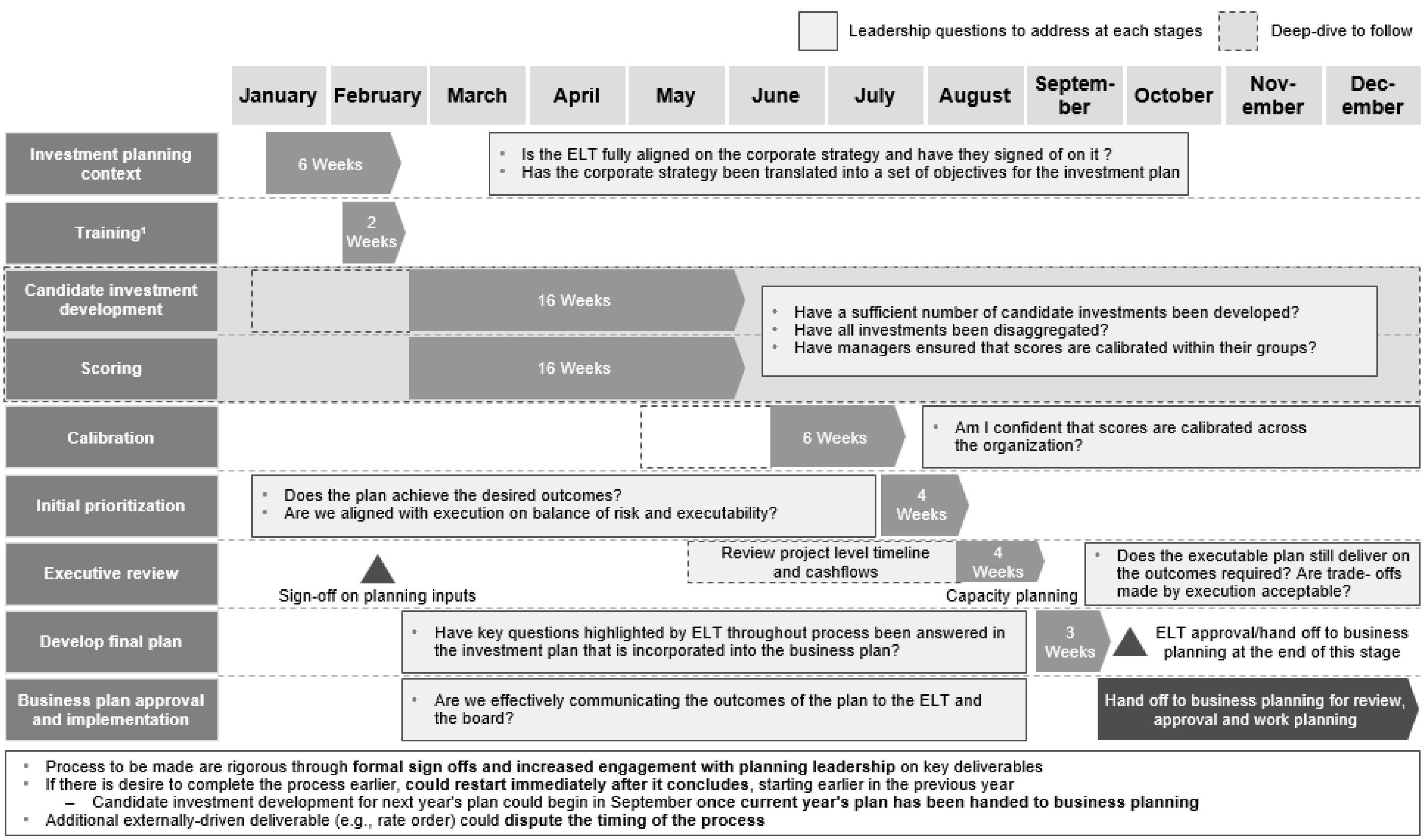
Number of projects cut	Sample project cut
• --	• --
• 9	• $1M air break switch replacement • $13M component replacement • $0.6M fire direction upgrade program
• 17	• $140M station rebuild • $50M switchyard and component replacement • $50M transmission line refurbishment

Reviewing these scenarios allowed for sensitivity analysis of each plan's risk mitigation potential. Hydro One conducted further prioritization once it received its 2017-2018 Transmission decision, leading to further capital reductions and another discussion of the tradeoffs of different levels of spending.

A final key component of a planning process is ensuring that stakeholders understand how the process works and how their investments are prioritized. In interviews, internal stakeholders have indicated that Hydro One's revised risk-based prioritization represented an improvement over prior cycles in terms of transparency and objectivity, but that there is still some room to continue education on how the process works.

Based on this and other feedback, Hydro One is taking a number of actions to continue to improve along this dimension. As part of its steady state calendar (included as Exhibit 27), Hydro One intends to continue to provide education on the risk scoring and prioritization process each year as the process begins to ensure that past participants are re-familiarized with key steps, and that new participants understand how the process works and the expectations from participants.

Exhibit 27: Hydro One's proposed steady state investment planning calendar



1. Corporate strategy defined and translated to planning objectives prior to commencement process training

To address some of the challenges in prioritizing a large sleeve of spending, Hydro One had indicated they intend to engage in more detailed strategic capital allocation during the strategy development phase of future planning cycles.

5. Assessment of Hydro One's capabilities in revise and approving plan

This step involves how a company revises its draft plan and engages senior leadership to finalize it. In involves the following activities:

- Reviewing and editing the draft plan that emerges from the prioritization process
- Pressure testing proposed investments to ensure they are justifiable and financially sound
- Engaging senior leadership to review and approve the plan

Best-in-class planning processes are characterized by the thoroughness of the revision phase. Plans are reviewed in detail by executing lines of business to ensure feasibility of execution. Plans are reviewed by team leaders, executives, and the Board, who provide timely feedback that helps shape the final plan. Reviews with senior leaders address rate impact considerations to ensure that they understand and can weigh in on the impact of the plan on customers. Quality assurance is conducted on the draft plan to minimize errors.

A typical utility planning process may involve less thoroughness in one or multiple aspects of review, but still involves multiple rounds of plan review ahead of approval. These include execution review, where the executing lines of business may only review investments in the initial years of the plan, and senior leadership reviews and quality checks.

A less mature process, in contrast, may be missing key elements. There may be limited opportunities for execution review, resulting in a plan that is difficult or impossible to execute. The executives and board may provide "rubber stamp" approval of the plan, without engaging on its details. There may be no time or process for quality assurance.

We have defined the specific capabilities related to this process step and the spectrum of maturity for each below in the rubric for this capability, shared in Exhibit 28.

5

Exhibit 28: Rubric: Revise and Approve Plan

Plan revision and approval	Process by which a company: • Evaluates the draft plan emerging from the prioritization process • Pressure tests proposed investments • Engages senior leadership to approve plan

Capability	Characteristics of "1"	Characteristics of "3"	Characteristics of "5"	Benchmark for "5"
Plan reviewed for execution feasibility	• Minimal input from executing lines of business (LOBs) into plan	• Executing teams review plan but given insufficient time or authority to make significant changes to contents	• Robust execution review of plan with opportunities to modify inclusion of investments based on feasibility to execute	• IBP
Plan reviewed for financial considerations and rate impacts	• Plan accepted as-is; limited rate impact review	• Financial and rate impact of plan reviewed; minimal opportunity to alter plan substantially if review not aligned with objectives	• Plan reviewed for financial impact and rate impact considerations; opportunity to adjust plan if misaligned • Consideration of plan impacts in context of overall customer bills	• IBP
Plan benefits beyond risk mitigation considered in review	• Plan reviewed primarily with internal focus • Limited understanding of plan benefits beyond risk	• Plan reviewed qualitatively for impact on key outcomes (e.g. reliability, safety)	• Plan reviewed quantitatively for impact on outcomes (e.g. reliability metric improvement, safety improvement)	• IBP • ISO
Sufficient management/board engagement with plan	• Management/board engages only at final approval	• Management engages prior to final approval, provides feedback capable of being incorporated into plan • Board engaged nominally on plan approval	• Management/board offers multiple rounds of guidance and have opportunity to provide meaningful feedback prior to final approval	• IBP
Quality assurance conducted on draft plans to reduce errors	• No time dedicated to QA checks and adjustments for mistakes	• Plan owners have modest dedicated time for plan review • Error checks at driver level but no audit of underlying inputs	• Plan owners have substantial time dedicated to quality assurance reviews of plan ahead of exec review and finalization • Error checks at all levels of planning input	• IBP

Hydro One exhibits several strengths on this dimension of the planning process and recent improvements have contributed to a robust review process. Scoring a 4 out of 5, Hydro One's review process puts it in line with leading utilities and close to best-in-class on many dimensions. Hydro One's sub scores on this dimension are included in Exhibit 29.

5

Exhibit 29: Maturity Assessment: Revise and Approve Plan

Capability	Score (1 – 3 – 5)	Comments on score
Plan reviewed for execution feasibility	4*	• Executing LOBs participated in all challenge sessions • Evidence of significant increase in time allocated vs. prior years (~3-4 mos of engagement vs. 2 weeks at end of plan) • Some feedback timing remained insufficient • Unfamiliarity with new process may have caused perceptions of insufficient timing; will likely improve in steady-state
Plan reviewed for financial considerations and rate impacts	4	• Proposed rate and earnings impacts of plans reviewed multiple times ahead of plan finalization
Plan reviewed for impact on customer outcomes	4	• Plan reviewed for quantitative benefits where possible (e.g. reliability) • Plan benefits primarily discussed qualitatively in review sessions
Sufficient management/board engagement with plan	4	• Two sessions conducted with ELT to review plan, supplemented with written updates between meetings • Additional ownership and review at VP level vs prior years • Board given visibility into high level plan details ahead of final review but limited time in schedule to revise plan meaningfully
Quality assurance conducted on draft plans to reduce errors	4*	• QA conducted throughout process (e.g. calibration, ahead of challenge sessions, final review) • Expected steady state process embeds more time for review vs. 2017

Hydro One's strengths stem from the time and attention dedicated to plan review throughout the organization as part of the new planning process. Hydro One has implemented a strong review process for its plans, with multiple levels of execution and leadership review through challenges sessions, and multiple discussions with the executive leadership team, culminating in final board review.

A key step in evaluating plans is ensuring sufficient time for executing teams to review draft plans and provide input on the company's ability to execute them. Hydro One's planning team began engagement with executing lines of business in late May to review key planning inputs, including cost estimates, and began execution reviews of draft plans in August; this cadence allowed for early alignment to avoid later churn on data inputs such as costs, and two months of execution review in August and September once draft plans were created.

Another critical step in plan review is executive reviews of the plan's key details and expected outcomes. Hydro One's strengthened its challenge session process in 2017 by increasing the number of sessions and expanding participation. This helped strengthen the level of executive engagement by introducing new forums for review between managers, directors, Vice Presidents and the COO ahead of reviews with the executive leadership team (ELT).

Executive leadership reviews occurred at multiple stages in the process as the plan matured. Initial reviews in July and August focused on educating leadership on the new planning process and high level plan details, such as initial guidance on the proposed rate impact of draft plans, while subsequent reviews provided more detailed summaries of the plan, including details on categories of spending and more robust rate and tariff impact discussions. These reviews also included discussions of the expected outcomes of the proposed investment plan, including qualitative and quantitative outcomes. Examples of the materials supporting these reviews is included in Exhibits 30-32.

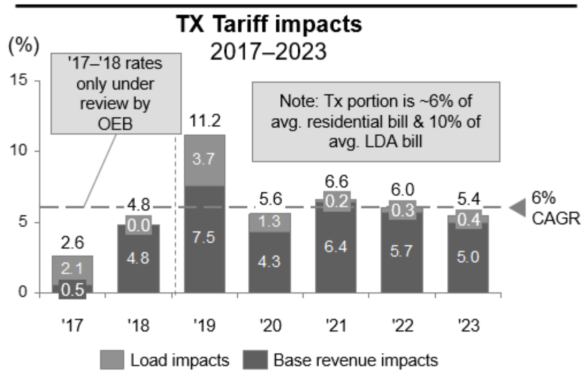
Exhibit 30: Sample of materials from ELT review of investment plan

	To meet customer needs, Hydro One will…	Highlighted Tx Investments	
Optimize the Core	Be an industry leader in **Safety & Environment** for our employees, contractors, and the public. Achieve and maintain "World Class" safety performance.	• **Journey to Zero** and Embedded Safety by Design programs • $3.9B which mitigates safety risk (e.g., $301M for targeted line insulator programs)	• $40M in condition assessments and patrols • Reducing environmental risk (e.g., $89M for PCB replacement, $22M for transformer oil leak reduction)
	Deliver improved **Reliability** to our customers, incorporating their input and priorities. Maintain top quartile/tier performance.	• $3.1B at 55 stations • $252M in Cyber Security	• $1.1B on lines to replace line segments in poor condition on 71 circuits • $61M[1] for new Control Centre
	Provide **Cost Effective** service to our customers by improving our productivity and continue to meet our budgeted commitments.	• Reduced planned spend to respond to customer and regulatory feedback	• **$431M[1] in total productivity savings** • Initiatives to extend asset life like Tower Coating ($170M)
	Always be there for our **Customers** with a seamless experience in all interactions. Seek continuous improvement in meeting our customer commitments.	• Work with customers to resolve power quality issues • $106M spend ($419M gross) for **new customer connections**	• $905M in development capital to build **new capacity to enable growth**
Bring Innovation to the Core	Pursue continuous **Innovation** in our work programs to maintain a reliable and affordable transmission system. Pursue grid modernization opportunities provided by emerging technology to enhance system visibility and automation.	• Drones, fleet electrification and advanced sensor pilots • $72M in new analytic tools	• $20M for **remote monitoring and automation** • $2.3M for new customer portal to improve customer service

1. Tx allocation

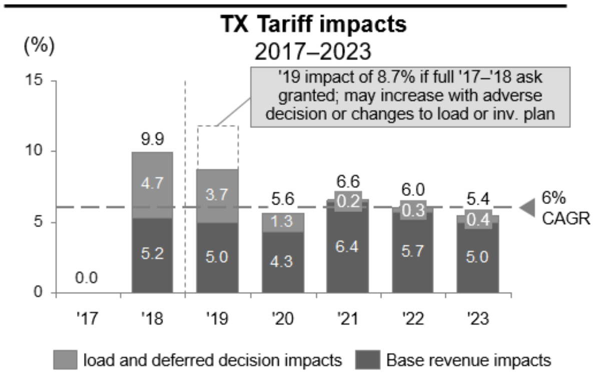
Exhibit 31: Rate impact preview from August ELT communications

Tariff impacts: July 25 ELT



- Key assumptions
  - Tx 2017 and 2018 rates approved applied for in the application
  - Includes increased revenue required and decreased load forecast

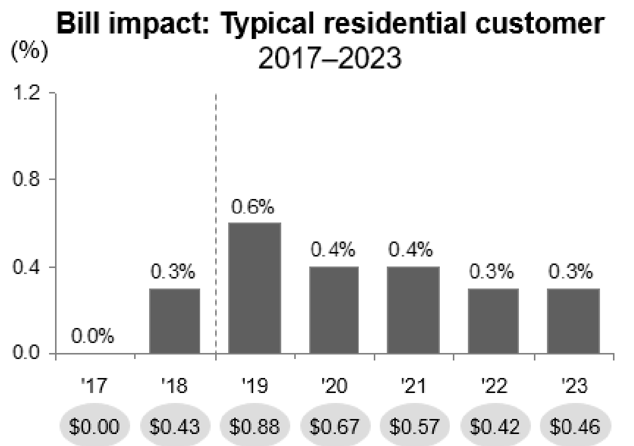
August 2017 updated

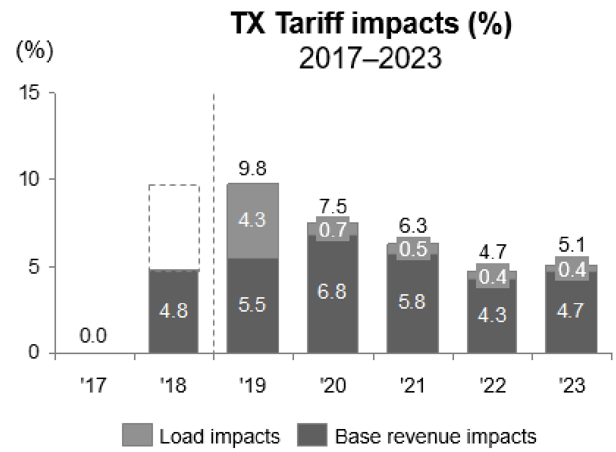


- Key changes
  - '17 revenue increase and load impact recovered in '18 as 1 year temporary increase
  - Larger than planned increase in 2018 results in a comparably smaller change in 2019

Exhibit 32: 2019 Tariff and Bill impact discussion from final ELT approval meeting

Final Investment Plan and CCC





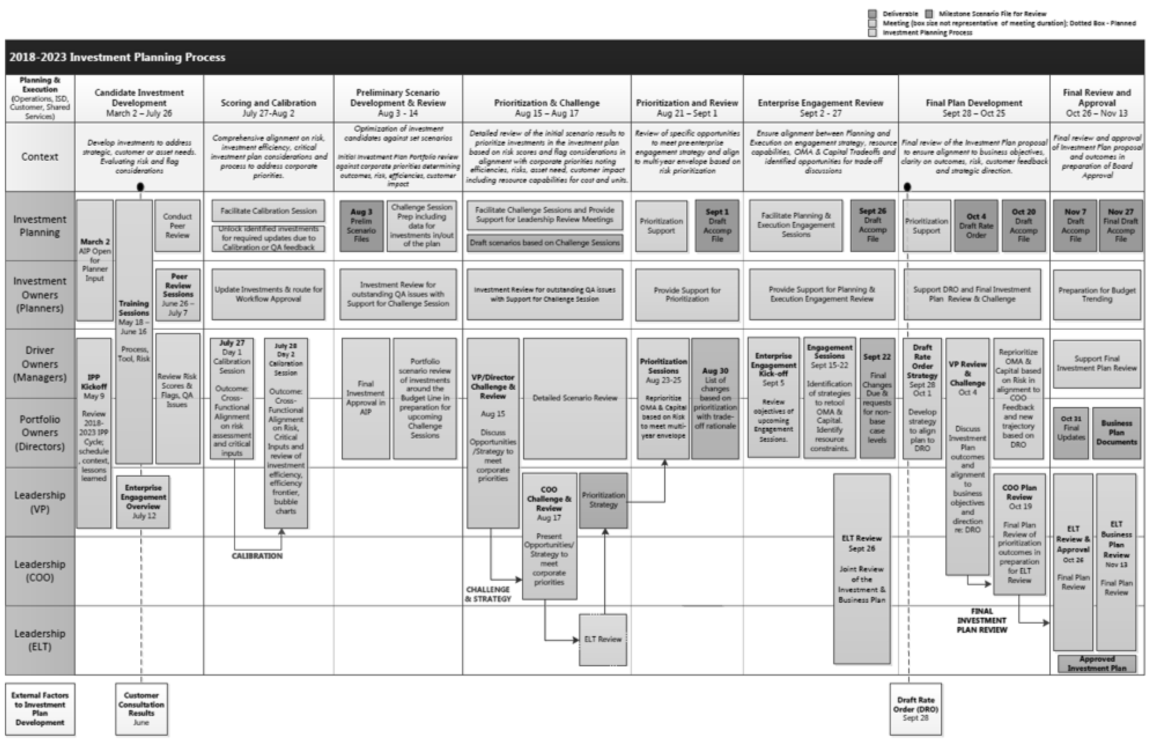
- Key changes
  - Loss of Deferred revenue in 2018 creates lower bill impact
  - Increases in load and lower prior year revenue causes larger impact in 2019, which is the first year of the next filing

- Key changes
  - Deferred decision impact removed in 2019
  - Tariff impacts increase slightly in 2019 and 2020 due to lower previous years revenue
  - Reduced rate impacts in later years

Hydro One's leadership reviews of the plan culminated in leadership approval at the end of October, incorporation of the investment plan into Hydro One's overall business plan in November, and final approval by Hydro One's board in December. Hydro One's timeline for executive review allowed substantial time for leadership to provide feedback on draft plans and for teams to incorporate it to meaningfully change the plan, in line with strong planning processes we have observed.

In addition to executive review, Hydro One's 2017 planning timeline provided sufficient time for quality assurance reviews of initial plan inputs ahead of prioritization, and reviews ahead of executive leadership reviews (see Exhibit 33). In its steady state calendar, Hydro One has allocated additional time for thorough quality assurance reviews consistent with best practice (see Exhibit 27).

Exhibit 33: Enterprise Engagement Schedule for 2017 Planning Process



Hydro One's revised process includes opportunities for quality assurance checks at multiple points in the process, including during calibration sessions, when risk scores are reviewed and sense checked, and errors can be caught before the plan is prioritized.

In the process supporting the 2019-2023 plan, Hydro One's review period was slightly more constrained, as it received its 2017-2018 Transmission decision in September 2017. The decision impacted Hydro One's draft plan, and required effort from the planning and finance teams to review the decision's impact and make changes. This occurred as Hydro One was preparing for its final executive leadership reviews of the plan, leading to compressed timelines and reduced time for review vs. expectations. These circumstances were somewhat mitigated by the opportunity for multiple prior reviews leading up to September, so many of the key components of the plan had already undergone a quality check. We expect that these circumstances would not persist in future planning cycles, given Hydro One's transition from 2 year cost of service filings to a 5 year filing timeline. As a result, we would expect Hydro One to have sufficient time for quality assurance review and executive reviews embedded in its future planning cycles.

6. Execute plan and track outcomes

The investment planning process ends with the plan transitioning into the execution phase. While plan execution encompasses a broad group of activities, the key planning components are included below:

- Tracking the execution of the plan and the performance of investments, based on metrics aligned to established goals
- Leveraging performance data to make continuous improvements to the process and future plans

A utility with a best-in-class planning process excels at both of these components. It employs a comprehensive set of quantitative metrics with which it tracks performance, including productivity. Performance against plan is given high visibility within the organization, so that leaders are aware if executed projects align to those planned in terms of impact and budget, and have the opportunity to adjust if not. Results of projects are systematically fed into future planning, so that lessons learned inform future project design, and productivity drives continuous improvement.

A typical utility planning process may be more qualitative and informal in its tracking. Its metrics may be a mix of qualitative and quantitative, with some relevant capabilities for which there are no established metrics. Execution tracking may be primarily financially-oriented and less frequent than is best practice (e.g., quarterly or more seldom). Outcomes and lessons learned may feed back into planning informally, without a clearly established process.

A poor planning process may be characterized by inconsistent or nonexistent metrics, infrequent tracking, and lack of feedback between execution and future planning.

We have detailed the spectrum of maturity for each of these capabilities in the rubric in Exhibit 34.

6

Exhibit 34: Rubric: Execute plan and track outcomes

Follow-up and tracking

Process by which a company:
- Tracks execution of plan and performance of investments using defined metrics
- Leverages performance data to make continuous improvements to process and future plans

Capability	Characteristics of "1"	Characteristics of "3"	Characteristics of "5"	Benchmark for "5"
Metrics chosen align to desired customer, operational and regulatory objectives and outcomes	• No tracking of metrics • No plan objectives or desired outcomes to which metrics can be linked • Metrics change too frequently for comparison	• Metrics mostly aligned to desired outcomes, but may lack comprehensiveness or specificity • Metrics allow for assessment of improvement over course of planning cycles • Target setting may be incomplete (e.g. short or long term only)	• Clearly defined metrics and targets (long term and short term), fully aligned to desired customer, operational and regulatory outcomes • Allow for quantitative assessment of improvement over time	• IBP
Executed investments align to finalized investment plan and evidence	• Execution diverges significantly from finalized investment plan, with limited tracking of causes or: • Plan executed highly rigidly, inhibiting response to changing circumstances to meet desired outcomes	• Capacity to fully execute finalized plan levels but potential for significant change in mix of investments; • Modest focus on outcome achievement; primary focus on spend levels	• Significant alignment between mix of investments executed and finalized plans • Sufficient flexibility in plan to respond to unexpected challenges while still achieving plan outcomes	• IBP
Execution and performance tracked in-year	• Limited execution tracking occurring in-year; low frequency of data collection	• Changes tracked; reviewed quarterly at a minimum • Required justifications for changes, focused on spending primarily	• Changes tracked, drivers of change identified and justified in consistent (e.g. monthly) forum • Discussions focus on impact on performance in addition to spending	• IBP
Execution data and outcomes tracked and used to inform future planning	• No unit cost measures tracked • No tracking of variance from estimates • No incorporation of lessons learned	• Unit cost efficiencies tracked and fed into future plans • Limited analysis of variance from estimates • Informal use of lessons learned to shape future projects	• Unit cost efficiencies tracked and fed into future plans • Analysis of variance from estimates used to improve estimation process • Systematic approach to incorporating lessons learned into future projects	• IBP

Hydro One has made significant efforts to improve its plan execution and tracking process in recent years. As a result, we find that the company has a strong process in place on several capabilities within this step, with some room for improvement in ensuring a clear feedback mechanism between performance tracking, decision making around redirection and plan adjustments, and strategic inputs for future planning cycles. Overall, we have scored Hydro One as a 3.5/5 on this capability. Additional detail on Hydro One's scores on this capability is included in Exhibit 35.

6

Exhibit 35: Maturity Assessment: Execute plan and track outcomes

Capability	Score (1 – 3 – 5)	Comments on score
Metrics chosen to align to desired outcomes	3*	• Chosen metrics comprehensive and map to key stakeholder outcomes • Scorecard expected to continue evolving as Hydro One receives regulator feedback and refines its tracking capabilities • Targets defined at 5 year level; opportunity to define targets more granularly for scorecard metrics to ensure progress towards 5 year goals and inform redirection
Executed investments align to finalized investment plan and evidence	3	• Hydro One has historically struggled to fully execute proposed capital budgets • Evidence shared demonstrates improvement in ISAs/budget; however, unclear whether mix of investments aligns to filed evidence • New redirection committee expected to help address alignment to plan
Execution tracked in-year	4*	• Actual vs plan tracked and shared in monthly reporting; initial focus on spending vs. overall performance vs. plan • New redirection committee establishes forum for in-year course correction, with senior participation on committee
Execution data and outcomes tracked and used to inform future planning	4	• Recent effort undertaken to strengthen collection of unit cost data to drive productivity • Information then used to reduce future estimates and drive productivity through budgets • Significant progress made in 2017, though not all types of investments driven by unit cost data yet

Hydro One uses metrics to track performance against key objectives and desired outcomes. Hydro One tracks performance at cascading levels through the organization (e.g. at the overall organizational level, at the operations group level, and for groups within operations), consistent with best practices we have observed.

In revising its performance measures over the past two years, Hydro One has increased its focus on unit cost metrics in an effort to increase its ability to measure productivity and use these metrics to drive continuous improvement through the business. Hydro One has added unit cost metrics for brush control and forestry and per FTE metrics for project management and construction to its scorecard to increase its focus on productivity and efficiency.

As part of its effort to improve performance tracking, Hydro One has set 5 year targets for improvement over historical average performance on each metric over the full term of the plan. The targets indicate the outcomes Hydro One's investment plan is expected to deliver. Hydro One set these targets through a combination of qualitative and quantitative analysis and is continuing to evolve its predictive analytics to improve its ability to translate planned investments' risk mitigation potential into customer outcomes. In addition to improving its predictive analytics, Hydro One can also continue to improve on this dimension by ensuring that team and division metrics align to the overall goals set by leadership on an annual basis and by setting annual goals for its published metrics to ensure performance is tracking towards the overall outcomes Hydro One is seeking to deliver with its 5 year plan.

Several of Hydro One's performance metrics focus on tracking execution progress, a critical capability in ensuring plans deliver on desired outcomes. Hydro One has demonstrated recent progress on project execution, with metrics indicating its ability to largely meet planned in service additions and planned capex in a given year. Hydro One is now focusing on its processes to monitor how executed investments track to plan, and strengthening its processes to ensure that when capital is being redirected, the drivers and impacts of changes are well understood.

Exhibit 36: Sample Hydro One Execution metrics

Measure	Measure Description

Transmission System Plan Implementation Progress	The *TSP Implementation Plan Progress* measure compares the total actual in-year sustainment, development, and operating expenditures for in-service additions to the total internal company scorecard budget expenditures for in-service additions, including any OEB carry-forward variance. This metric cannot be benchmarked against other utilities.
Capital Expenditures as % of Budget	Progress is measured as the ratio of actual total capital expenditures to the total amount of planned capital expenditures. This measure can be benchmarked against other utilities.

	2014	2015	2016
TSP Implementation Progress	99	105	100
Capital Expenditure as % of Budget	90	106	105

All utilities strive to strike a balance between executing proposed plans and remaining flexible to respond to unexpected events and changing circumstances on their system. Best in class utilities tend to have clear processes around tracking variances from plan and using data on system performance and resource availability to help make decisions to redirect capital. Hydro One has robust reporting on financial metrics tracking execution vs. plan on a monthly basis that is communicated to relevant stakeholders. In an effort to improve its understanding of the causes and potential implications of variances from the plan, Hydro One introduced a redirection committee in September 2017 to facilitate not only financial tracking of plan execution and potential changes, but also provide a forum for operations leadership to understand the root causes of variances, and review the impacts on the organization, including the impact on key outcomes such as reliability (see appendix for the terms of reference for the Redirection Committee).

Hydro One's redirection committee has participation from senior leadership of relevant lines of business, including the Vice Presidents in charge of execution and planning. The committee meets monthly and provides a forum to discuss the financial impact of changes to investment plans, including acceleration or delay of projects, and the likely impact on customer outcomes. While the committee is relatively new, its existence and the scope of its mandate provide evidence that Hydro One is moving towards best in class execution tracking with an aim towards enabling better decision-making around in-year and in-planning term adjustments.

A key function of tracking performance and plan execution is to use data to create a feedback loop to improve future plans. Hydro One has increased its focus on collecting unit cost data by tracking performance on identified productivity initiatives. This information can inform future budgeting and help ensure Hydro One's productivity goals are realized.

A final component of tracking execution information is to use lessons learned from projects and programs to improve future execution, which Hydro One does. Hydro One has instituted a formalized lessons learned process to ensure other types of information gathered from execution are incorporated into future planning. There is a strong process in place at a tactical level, where specific issues identified in project execution are reviewed and given owners for resolution. There are also new efforts in place to be more strategic in understanding trends that emerge in execution for certain types of investments and incorporating learnings into project development phase.

Hydro One is working to improve several capabilities related to plan execution and tracking, including improving its predictive analytics to more clearly tie outcomes to plans and continuing to strengthen the feedback mechanisms between plan results and future decision making through the efforts of the redirection committee and a continued focus on capturing data and lessons learned as plans are executed.

7. Oversee and govern process

Throughout each step in investment planning process, strong oversight and governance are critical to ensuring planning procedures are adhered to. Governance involves the following activities:

- Organizing the investment planning process and dedicating resources to its execution
- Outlining roles and responsibilities related to the planning process
- Documenting the policies and processes related to the investment planning process

We have observed a range of maturity levels in ensuring strong governance and oversight for planning processes. Best-in-class governance involves clearly defined and documented processes that are well understood throughout the organization. Stakeholders understand the roles and responsibilities of those involved in the process; these roles, responsibilities, and incentives support objective planning. The planning process is enabled by the dedication of sufficient internal resources. The organization conducts routine internal audits resulting in recommendations for process improvements.

Typical maturity around process governance is characterized by many of the same strengths; processes are clearly defined, resources are sufficient, and policies are well-documented. Compared to best-in-class governance, the organization's understanding of the planning team's role may be more modest, or there may be some gaps in the thoroughness of process documentation and resource allocation.

Lack of resources, unclear roles and responsibilities, and poorly defined or nonexistent documentation are all characteristics of poor governance.

We have detailed the spectrum of maturity for each of these capabilities in the rubric in Exhibit 37.

7

Exhibit 37: Rubric: Governance and oversight (I/II)

Governance and oversight

Process by which a company:
- Organizes investment planning process and dedicates resources to its execution
- Outlines roles, responsibilities, and accountability related to IPP
- Creates appropriate documentation for policies & processes

Capability	Characteristics of "1"	Characteristics of "3"	Characteristics of "5"	Benchmark for "5"
Sufficient time and resources allocated to IPP by management in business planning cycle	• Proposed planning cycle duration prevents proper execution of multiple process steps • Insufficient resources prevent proper execution of multiple process steps	• Time sufficient to produce plan but too short to conduct robust challenge and QA, or: • Planning cycle too long and results in executed plan being based on stale data and objectives • Insufficiencies in either financial or personnel resources dedicated to investment planning process • Stakeholders outside planning dedicate insufficient time to plan	• Sufficient time allocated to process within planning year to enable each step to be conducted at high quality level but not so long as to risk plan being outdated • Timeline management engagement within cycle • IPP team empowered with sufficient budget and resources to ensure high quality process • Robust engagement from all firm stakeholders to ensure quality plan	• IBP • ISO
Roles defined for designing, reporting, and executing IPP	• No clear accountability for each step in IPP	• Accountability clear, but no escalation mechanism for non-compliance	• Parties fully accountable with clear escalation authorities and consequences for poor performance	• ISO
Roles and incentives support objective process	• Process exposed to potential for "gaming" by investment owners • Insufficient reviews and challenge sessions to mitigate individual biases	• Subjectivity embedded in process at key steps • Reviews and challenge sessions exist but do not focus on identifying bias	• Investment selection process relies substantially on objective criteria and inputs • Reviews and challenge sessions specifically focus on mitigating individual biases	• IBP

7

Exhibit 37: Rubric: Governance and oversight (II/II)

Governance and oversight

Process by which a company:
- Organizes investment planning process and dedicates resources to its execution
- Outlines roles, responsibilities, and accountability related to IPP
- Creates appropriate documentation for policies & processes

Capability	Characteristics of "1"	Characteristics of "3"	Characteristics of "5"	Benchmark for "5"
Processes & policies sufficiently documented	• No formal documentation of processes & policies	• Processes & policies documented for most high-impact and frequently conducted processes, but with no clear update cadence • Documentation is available to investment planning team but is not distributed to wider organization	• Processes & policies are consistently documented, updated, and widely accessible • Evidence filed with regulator aligns with internal documentation	• ISO
Internal process audits conducted	• No internal audits conducted to assess process quality and/or adherence	• Informal self-assessments conducted periodically to assess process quality and/or adherence	• Comprehensive internal audits conducted periodically to assess both IPP process quality and adherence to processes	• ISO

Hydro One has demonstrated strong performance on this capabilities, scoring a 4.4 out of 5. Hydro One's investment planning process contains many elements of effective governance. Hydro One used the opportunity provided by making improvements in 2017 to thoroughly document the process and strengthen participants' understanding of roles and responsibilities. There is room for improvement, though, on ensuring sufficient resources are allocated to planning given how critical the planning process is to the organization, and, ultimately, its customers. Our evaluation of Hydro One's capabilities is included in Exhibit 38.

7

Exhibit 38: Maturity Assessment: Governance and oversight

Capability	Score (1 – 3 – 5)	Comments on score
Sufficient time and resources allocated to IPP by management in business planning cycle	3*	• Process is an area of significant organizational focus • Planning cycle given sufficient time in business planning calendar under steady state, but condensed in transition years • Some indication that resourcing beyond direct IPP team (e.g. planners, service providers, execs) was strained given late decision
Roles defined for designing, reporting, and executing IPP	5	• Clear definition of roles and responsibilities within planning organization
Roles and incentives support objective process	4	• Rigorous challenge process aims to eliminate bias but opportunities to strengthen objectivity of risk scoring process • Challenge process documentation quite rigorous
Processes & policies sufficiently documented	5	• Recent enhancement effort significantly strengthened process and policy documentation
Internal process audits conducted	5	• Significant internal audit resources devoted to IPP in recent years • Recommendations acted upon and results tracked

Hydro One has used the experience of revising its planning process to strengthen its documentation of process steps, and provide education to team members. Planners each have access to relevant documents that outline the process and methodology of Hydro One's risk-based prioritization, and Hydro One has enhanced education materials that it will use to outline the process for future cycles. An example of codified roles and responsibilities is included in Exhibit 39.

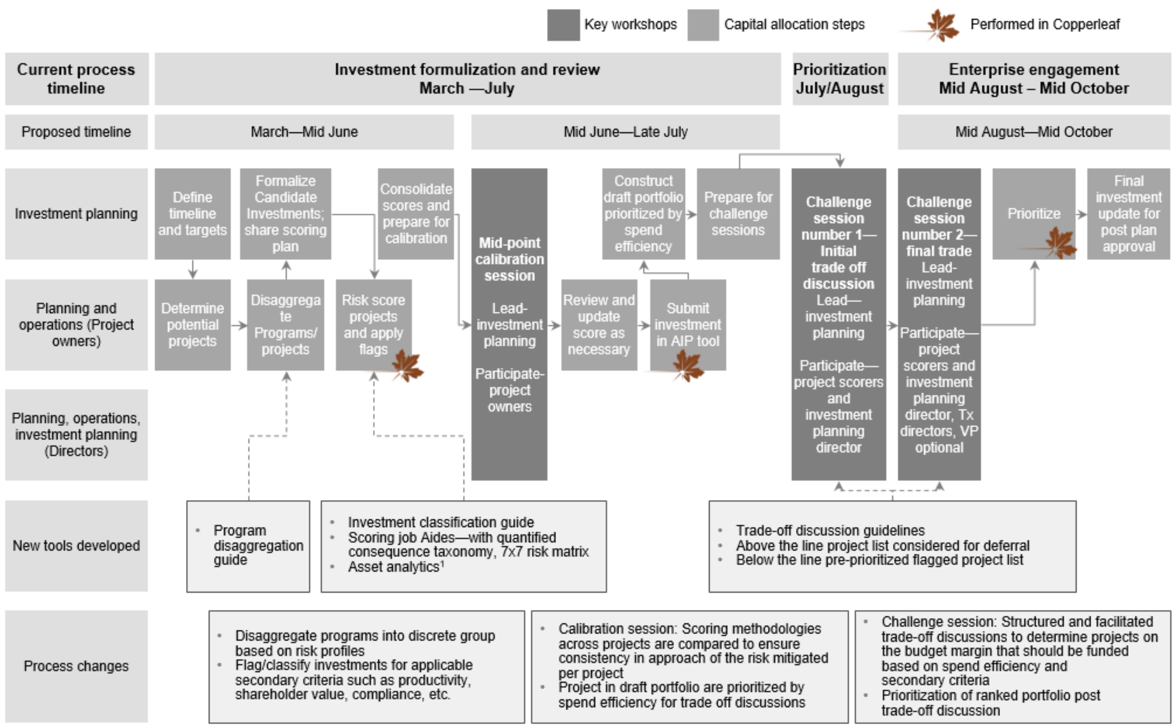
Exhibit 39: Planning Process roles and responsibilities

Group	Roles	Responsibilities
Investment management	• Manage Transmission prioritization and optimization • Facilitate scoring • Build and finalize portfolio	• Collect and quality review project lists from Driver Owners; schedule and facilitate calibration, challenge, trade-off decision, and review meetings • Assign scorers and facilitate scoring sessions • Schedule and facilitate meetings with other SMEs • Ensure each flag has the required documentation and review disaggregation/bundling decisions • Prepare and manage all material for major meetings, facilitate challenge sessions and confirm finalized portfolio
Leadership (VC, C-Suite)	• Participate in Challenge session 2 • Approve portfolio	• May attend Calibration session, Challenge session training workshop • Participate in Challenge session • Approve pre-prioritization portfolio
Portfolio Owners (Director)	• Final portfolio-level accountability for portfolio • Oversee calibration of project scores • Challenge portfolio	• Make final call on scoring of a contentious project • Attends Calibration session • Participates in Challenge session 2 alongside leadership to ensure portfolio meets strategic objectives • Approves pre-prioritization portfolio
Driver owners (Manager)	• Originate and score projects • Calibrate project scores • Challenge portfolio	• Responsible for disaggregating programs/bundling projects • Accountable for consistent and calibrated scoring within their group of investments • Participate in Calibration Session and Challenge Sessions, and shares perspective on investments to pull in/push out of portfolio
Investment Owners (Planners	• Serve as SMEs for scoring	• Submits candidate investments to generate project list for Investment Management • Gather project specifications (name, description, $ investment) to share with Investment Management Risk score project as directed by IM team (likely ~10–20 minutes per project)

While the Investment Owner will be the official scorer of his/her project, the ultimate responsibility of the final risk score assigned to a project lies with the Portfolio Owner

As part of developing this body of documents, Hydro One defined process steps and timing both for the 2017 process, that involved more detailed training and piloting of new system (Exhibit 40), and a steady state calendar that reflects how the process would unfold in a typical year going forward (Included as Exhibit 27 above).

Exhibit 40: Initial 2017 Process Map defined in May 2017



1. Hydro One tool for calculating consequence and impact risk scores for transmission station based on asset conditions

While the planning team received some feedback that 2017 schedule was compressed and therefore constrained some stakeholder resources given the changes to the plan that were introduced after the 2017-2018 Transmission decision was received, the steady state calendar is expected to provide sufficient time to execute planning process, including engage in required quality assurance and executive reviews.

Another key element of governance and oversight is the use of internal audits to review processes and ensure adherence to existing governance. Hydro One has a formal internal audit process that enables it to conduct reviews of key processes. Hydro One's internal audit process is robust and specific, including in identifying action items and tracking progress toward closure.

The legacy investment planning process was subject to an internal audit in 2015, with a follow-up audit conducted in 2017. In 2015, the audit found that asset analytics, the asset investment planning tool, and Hydro One's station centric approach were good initial foundations for the planning process, but the audit found controls ineffective ("Based on the specific areas reviewed, we conclude that controls are often ineffective and significant improvements are needed to ensure that a consistent investment planning process is used to produce a risk-based Investment Plan Proposal to address customer, asset and system needs"[2]). In a 2017 follow-up audit, the team found that Hydro One had made significant progress but introduced recommendations for how the planning team could continue to improve the planning process, which Hydro One's planning organization has begun addressing.

Hydro One is making continued efforts to ensure proper governance and oversight of the planning process. As mentioned above, Hydro One has introduced a steady state calendar that aims to address some of the key concerns around timing and resourcing that emerged in its first application of the new process in 2017. Hydro One is also implementing the recommendations from its internal audits to ensure it continues to close the gaps identified in those reviews.

V. Implications of our assessment for the upcoming transmission filing

On the whole, we assess that Hydro One's planning process will contribute to a robust Transmission System Plan. Hydro One has undertaken significant changes to its planning process that support a more rigorously developed and objective investment plan than in prior years. In particular, the general increase in rigor around scoring, calibration, and challenge sessions contributes to an improvement in plan quality. Some gaps in maturity, however, remain – specifically around the level to which investment options are informed by data, the timing of asset management strategy development, and the process to track outcomes and set interim targets to ensure plans meet Hydro One's five year goals. Of the key gaps identified, Hydro One has developed plans to continue to progress on these capabilities. In the areas where Hydro One is continuing to progress, we do not believe their current level of maturity significantly undermines the integrity of the plan being submitted.

[2] 2015 Internal Audit Documents – introduced during Hydro One's 2017-2018 Transmission application litigation

With respect to the use of data to inform investment options, Hydro One has made significant progress on by enlisting third party support to close the backlog in testing end of life assets. As a result, Hydro One is in a position similar to many utilities that have a large, aging asset base spread across a large geography – it has improved its use of data to develop investments, but 100% coverage for assets is not realistic. As a result, the judgment of experienced engineers is relied upon to help identify necessary investments.

In addition to continuing to improve the availability of data, Hydro One has continued to work to ensure comprehensive asset strategies guide its planning. Hydro One should ensure that its new asset management strategies are fully incorporated in the planning process for future cycles. When investment plans are not informed by asset management strategies, there can be a lack of consistency in the investment projects developed for submission to the plan, and the options developed may not address the most critical assets. Despite not having the revised asset management strategies fully in place ahead of planning, the team could rely on legacy documents to guide initial investment development that largely reflect Hydro One's longstanding philosophy on asset replacement and station-centric work planning. As a result, the lack of revised asset management strategies for all assets is unlikely to result in a misinformed plan and Hydro One's new strategies leave it well positioned for its next planning cycle.

Hydro One is continuing to progress towards being able to clearly link proposed plans to desired customer outcomes. In revising its risk scoring and prioritization process, Hydro One has been able to more clearly demonstrate how its investment plan mitigates risk. This enables Hydro One to make trade-offs between investments and different levels of funding based on risk as an outcome. Hydro One is continuing to evolve how it translates risk mitigation into meaningful customer outcomes. Hydro One has proposed 5 year targets for key scorecard outcomes that the investment plan is expected to help deliver, which were developed through a combination of quantitative and qualitative analysis to assess the expected results of the investment plan. This represents a strong initial effort to link plans to outcomes, though some gaps remain to being able to fully quantify the expected impact of plans. Doing so is difficult for almost any Transmission utility given the age of systems, availability of data and difficulty of predicting reliability performance on a redundant system. If Hydro One did not have a risk-based prioritization system that rates risk on dimensions linked to key outcomes (safety, reliability, and environmental risk), it would be more difficult to understand how Hydro One expects its plans to perform. However, with the combination of a rigorous risk-based prioritization and initial efforts to translate the plan into meaningful outcomes, we believe Hydro One has appropriate initial steps towards being able to predict the outcomes of its plan and deliver on its stated targets. Hydro One is continuing to progress on this effort by increasing the rigor of its predictive analytics to understand the impact investments have on key outcomes such as reliability, unsupplied energy and productivity. As a result, the relative lack of maturity on this dimension does not undermine the plan or the proposed outcomes it seeks to deliver.

VI. Conclusion and recommendations

In our assessment, Hydro One has made significant improvements in its planning process; has a process in place that is consistent with that of many utility peers; and excels in some areas of planning when compared to our leading peer set. Hydro One has strengthened the quality of its initial strategic inputs, improved its investment development and evaluation capabilities, introduced more rigorous scoring and calibration, and implemented a risk-based prioritization that improves the objectivity of its process. The resulting plan was thoroughly reviewed and will be supported by more rigorous execution monitoring and tracking than has existed in the past. While some gaps remain in ensuring assets decisions are guided by clear strategies and data, and linking plans rigorously to outcomes, none of these gaps significantly threaten the quality of the plan, and all are being addressed with specific initiatives.

As Hydro One continues to mature its planning capabilities towards a level consistent with best in class processes, they can consider continuing to focus on the following dimensions: continuing to strengthen the breadth and quality of data used to support the development of investment projects that address the most critical risks on the system; ensuring the process is guided by clear strategies that provide guidance on risk reduction and life cycle cost optimization, and strengthening long-term outcomes tracking and prediction capabilities to ensure consistent feedback between plan execution and future planning and goal-setting. Finally, Hydro One should ensure the processes and tools developed as part of the recent revisions to the process are continually reviewed and updated to ensure they continue to relevant to the organization and available to educate new participants in the process.

Appendix

Table of contents

Additional detail on BCG credentials

Additional detail on BCG credentials

Breadth of power and gas industry issues covered by our topic teams (I)

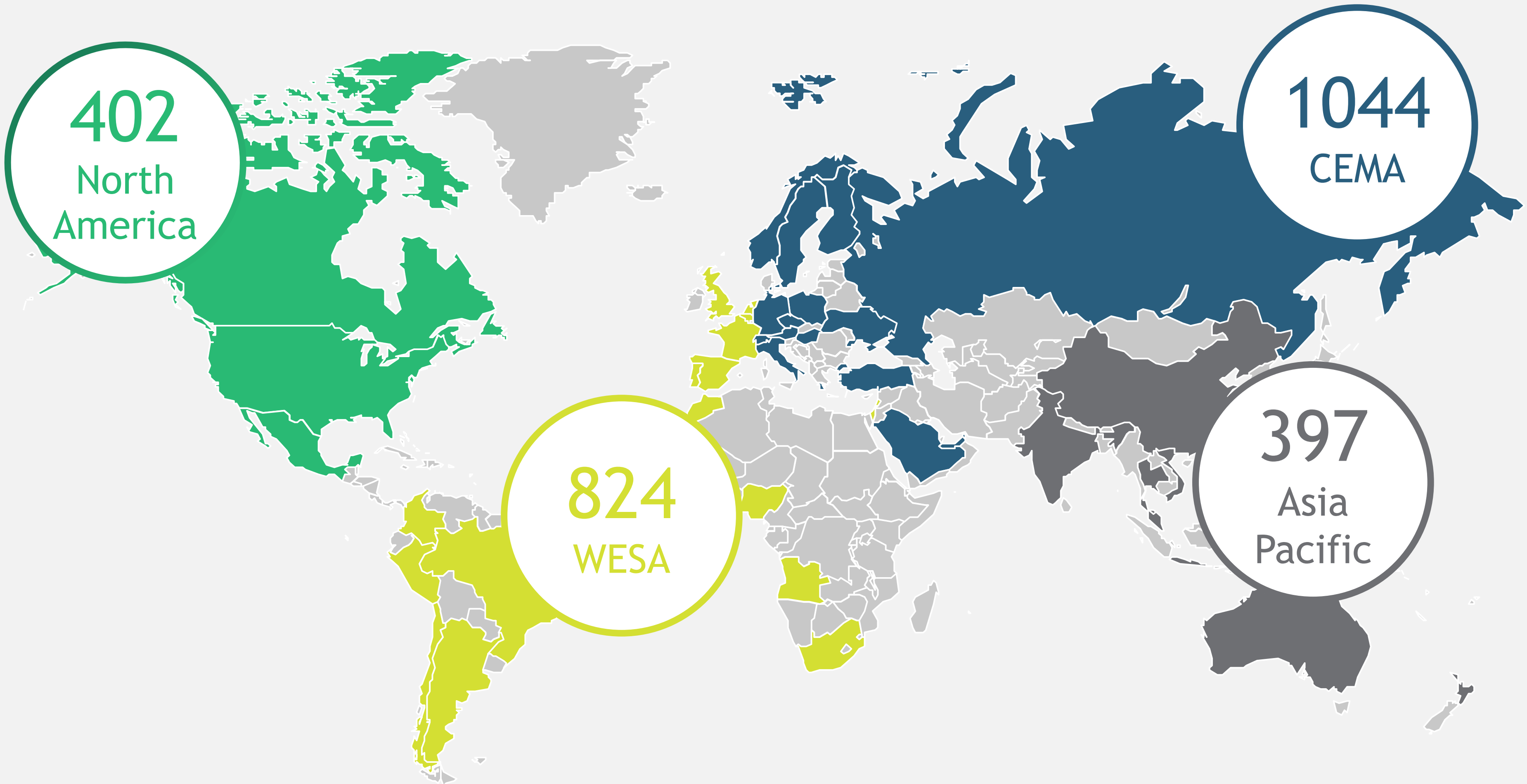
Topic	Generation operations	Nuclear	Networks and infrastructure/ smart technologies	De-central energy
Key themes	Lean generation • Lean organization • O&M excellence Large project management • Project management and processes • Contracting strategy BCG O&M benchmarks • Costs, staffing and organization Technical benchmarks • Availability, fuel efficiency & flexibility	Nuclear strategy • Governance model Power operations • Decommissioning • Operational excellence Nuclear growth • New built and investment • Risk analysis Fuel cycle	Transmission and Distribution • Strategy and corporate development • Operations and Organization • Smart Grids • Decentralized Generation	Market and Regulation Technology Business model • Customers • Offerings • Value chain Business build • Structure • Capabilities • Culture and Leadership

Additional detail on BCG credentials

Breadth of power and gas industry issues covered by our topic teams (II)

Topic	Utility business transformation	P&G retail	P&G markets and regulation
Key themes	Funding the journey • Operational excellence • Capital efficiency • Organizational simplicity • Revenue opportunities Winning the medium term • Service modernization • Business model and growth • Regulatory management • Portfolio restructuring Right team, organization and culture • Talent organization • Change management	Marketing and Sales • Customer Segmentation • Cost to serve/ Churn rates • Retail operations • Pricing/Cost to serve • Outsourcing	Fundamental market models • Power Generation Model Technology • Technological trends • Technology of conventional and nuclear generation Market Liberalization and Energy policy • Unbundling/Privatization • Third party access to infrastructure Price regulation • Network tariff setting • Subsidies and regulated

BCG has deep energy experience across geographies



> 2667 energy cases in all regions completed

Source: BCG Case Experience Aug2012- Sep2017

Also with deep experience across functional topics

Corporate development	Marketing, sales, and pricing	Operations	People and organization	Strategy	Technology advantage
1,073	196	813	603	1,014	251

Note: Some projects are cross-referenced and may be counted in multiple topics
Source: BCG case experience Aug2012- Sep2017

We work with the leading energy companies among top-25 in power and gas

Utilities
Serving 15 out of the top-25
(2016 Platts 250 Global Energy Co's)

1	Korea Electric Power Corp
2	National Grid Plc
3	Exelon Corp
4	NextEra Energy, Inc
5	Iberdrola SA
6	Southern Co
7	Enel SpA
8	Duke Energy Corp
9	Gas Natural SDG SA
10	Chubu Electric Power Co
11	American Electric Power Co, Inc
12	Public Service Enterprise Group Inc
13	CLP Holdings Ltd
14	Tokyo Electric Power Co
15	Dominion Resources
16	The Kansai Electric Power
17	Tenaga Nasional Berhad
18	Consolidated Edison
19	Tokyo Gas Co
20	Sempra Energy
21	Electricite de France SA
22	PPL Corp
23	Edison International
24	SSE plc
25	EDP—Energias de Portugal

Source: 2016 Petroleum Intelligence Weekly, Top 50 ranking of the world's oil companies; 2016 Platts 250 Global Energy Corporations (company rankings derived using a composite Platts formula based on asset worth, revenues, profits, and ROIC http://top250.platts.com/Top250Rankings), BCG Credentials

BCG leadership team bios

David Gee
Senior Partner and Managing director

David Gee is a Senior Partner and Managing director in the Washington, D.C. office of The Boston Consulting Group. Currently, he leads BCG's Energy and Petrochemicals practice in North America.

Prior to joining BCG, David was a Principal with McKinsey & Company where he led its U.S. refining and petrochemicals practice. He also was VP Strategic Planning for PG&E Corporation during the California Energy Crisis. Most recently, he served as President, North America for AES Corporation.
With more than 37 years' experience in the energy and chemicals industries, David's focus is on supporting a range of energy clients.

His principal areas of expertise include power generation strategy and operations; vertically integrated power and gas utilities; oil and gas exploration and production; and refining, petrochemicals, and downstream distribution.

Justin Dean
Partner and Managing director

Justin is a Partner and Managing Director working at the Boston Consulting Group. He leads the firm's Washington DC office.

Prior to joining BCG, Justin gained extensive experience in the energy sector (power generation, utilities, and sustainability) in consultant, project management and engineering capacities.

Justin is core member of BCG's energy sector practice and led a variety of projects within the power and utilities sector, including: Corporate Development / Due Diligence support, generation portfolio strategy assessment, T&D Ops improvement, and distributed generation/renewable/solar strategies. Justin also has significant transformational experience leading large Program Management Office (PMO) and Change Management efforts.

He holds a BS in mechanical engineering from the University of Virginia and an MBA from the Kellogg School of Management at Northwestern University.

Andrew Loh
Partner and Managing director

Andrew Loh is a Partner and Managing Director in the Toronto office of The Boston Consulting Group.

Andrew joined BCG in 2000 and is the Canadian Power & Gas Sector Leader and a core member of the Industrial Goods Practice where he has focused on Automation, Automotive, Engineering & Construction, and Mining & Metals. He has worked extensively on Strategy, Transformation, Corporate Development, Organizational, and Operations topics. Prior to joining BCG, Andrew worked as a research analyst at Merrill Lynch.

Andrew holds an Honors Bachelor of Commerce degree from Queen's University.

Additional detail on utility peer set

Summary of peer set (I)

Company name	Primary jurisdictions	2016 total assets (US $B)	2016 revenue (US $B)	Business lines
Exelon	US multi-state (primarily US Northeast) Canada (generation)	114	31	Electric transmission, distribution, generation Natural gas
IBERDROLA AVANGRID	US multi-state (Primarily US Northeast)	31	6	Electric transmission, distribution, generation Natural gas
Berkshire Hathaway Energy	US multi-state (Primarily US Southwest)	3[1]	0.5	Electric transmission
PG&E	US (California)	69	18	Electric transmission, distribution, generation Natural gas
Enbridge	US (Federal) and Canada (Federal, Alberta and Ontario)	69	28	Natural gas
Hydro Québec	Quebec	61	11	Electric transmission, distribution, generation

1. US Tx assets only
Note: All totals in USD; converted as of January 2018
Source: 2016 Company annual reports

Summary of peer set (II)

Company name	Primary jurisdictions	2016 total assets (US $B)	2016 revenue (US $B)	Business lines
Southern California Edison	US (California)	51	12	Electric transmission, distribution, generation
conEdison	US multi-state (Primarily New York)	48	12	Electric transmission, distribution, generation Natural gas
Xcel Energy	US multi-state (Primarily US Mid-west)	41	11	Electric transmission, distribution, generation Natural gas
BC Hydro	British Columbia	30	5	Electric transmission, distribution, generation
nationalgrid	UK, US Multistate (Primarily New England)	92[1]	21[1]	Electric transmission, distribution, generation Natural gas
SCE&G	US (South Carolina)	16	3	Electric distribution, transmission, generation Natural gas
LS Power Innovation and Investment in Energy	US Multistate	N/a[2]	N/a[2]	Electric transmission

1. Annual report as of June 30, 2017 2. Privately held
Note: All totals in USD; Converted as of January 2018
Source: Company annual reports

INVESTMENT REDIRECTION COMMITTEE – TERMS OF REFERENCE

1. PURPOSE

The purpose of the Investment Redirection Committee is to

- Oversee the redirection process whereby investment changes from the business plan are approved, documented, systemized and communicated to stakeholder line management to ensure that due process is followed when expenditure adjustments are made to capital, OM&A and in-service additions.

- Provide advice and direction on investment adjustments that are required to the business plan to address emerging business needs/risks or to seize opportunities related to the planning and execution of Hydro One's Investment Plan.

- Ensure integration and a common understanding across the enterprise regarding issues affecting the execution of Hydro One's business plan.

2. SCOPE

The Investment Redirection Committee shall advise regarding:

- The status of the release and execution of the Investment Plan over the business plan horizon including:
  - projects to fulfill customer and regulatory commitments or compliance to industry standards;
  - factors that are adversely affecting the timely release or execution of work; and
  - deviations from the approved Investment Plan and alternatives (including the redirection of future work releases) to address the deviations.
- The review and recommendation of adjustments to the execution of the approved Investment Plan, from Capital, OM&A and In-Service Addition perspectives, in response to prevailing industry and / or corporate circumstances[1].
- Redirection requirements and funding trade-offs which exceed the noted threshold (Appendix "A"), including those as a result of forecast updates, pending interim review of variances (IROVs) and business case summaries (BCS) with insufficient funding identified; while forecast changes will be identified retrospectively as redirection candidates, pending IROVs and BCS with insufficient funding shall be discussed, identified, and agreed to prospectively at the Redirection Committee prior to the approval.

[1] These adjustments will not change the current year's budget, which is approved annually by the Board of Directors; however approved redirection decisions will provide clear visibility to deviations from the approved budget and the resulting future year impacts.

- The management and review of capital and OM&A work programs and corporate common costs on a monthly basis; the redirection of OM&A must be balanced off with shareholder value with clear decisions to roll forward funds, redirect funds or bank funds (productivity).

Approval of redirection must be done in accordance with the EAR and adjustments must remain consistent with the funding levels, investment strategies, and performance outcomes approved by the Board of Directors.

When core committee members have insufficient EAR authority to approve redirection opportunities or the identified redirection impacts a business unit not represented on the committee (or invited as a guest), the COO shall table a redirection recommendation with the Executive Leadership Team (ELT) for approval at the Quarterly Capital Review meeting, or as required.

3. MEMBERSHIP

Membership of the Advisory Committee is outlined in Appendix "B".

IRC members may delegate an alternate person to attend the meetings.

Other staff may be invited to attend a portion of a meeting to provide briefings, updates or assistance on specific topics related to the release and execution of Hydro One's approved Investment Plan; this includes other members of the ELT (and their direct reports) who are not regularly represented at this forum to attend if/as items come up that are within their purview

4. REPORTING REQUIRMENTS

Following the review and recommendation of adjustments to the approved Investment Plan, investment level decisions will be documented and communicated, including the recommended change and rationale.

Updates on significant Investment Redirection Committee decisions, as well as recommendations related to reprioritization options that require an approval authority that exceeds that of members of the committee should be presented at the ELT's Quarterly Capital Review meeting.

5. MEETINGS and FORMAT

Meetings are scheduled once a month, typically during the fourth week of the month.

The output of the Redirection Committee Meeting shall be presented and discussed at the Operations Work Program Review and / or Monthly Operations Review, typically the second week of the subsequent month.

6. APPROVAL AND REVIEW OF TERMS OF REFERENCE

The terms of reference shall be approved by the committee.

Appendix "A"

Redirection Thresholds

Threshold	Description and Scope	Rationale
Tier 1	Individual investments with an absolute forecasted annual variance against the approved redirection budget greater than \$3M for Transmission and \$1M for Distribution for: • Capital Expenditures (net); • OM&A (net); or • In-service additions.	Aligned with the OEB filed Investment Summary Document (ISD) threshold: • Transmission = \$3M • Distribution = \$1M
Tier 2	Individual investments with an absolute forecasted annual variance against the approved redirection budget greater than \$1M within a driver with an absolute variance greater than \$3M for: • Capital Expenditures (net); • OM&A (net); or • In-service additions.	Aligned with the OEB filed Investment Summary Document (ISD) threshold: • Transmission = \$3M • Distribution = \$1M

Appendix "B"

Membership

Business Unit	Title	Members	Alternate
COO	Chief Operating Officer	Greg Kiraly	
Operations	VP, Planning (Chair)	Darlene Bradley	Bruno Jesus
Operations	Vice President, Transmission and Stations	Andrew Spencer	Kathleen McCorriston
Operations	Vice President, Distribution	Brad Bowness	
Operations	Vice President, Engineering	Bing Young	
Operations	Vice President, Shared Services	Rob Berardi	
Operations	Vice President, System Operations	Martin Huang	
Corporate Finance	Senior Vice President, Finance	Chris Lopez	
Technology	Senior Vice President, Technology	Colin Penny	
Customer Service	Vice President, Customer Service	Warren Lister	
Office of the President & CEO	Vice President, Office of the President & CEO	Stefanie Stocco	

David Gee

Partner and Managing Director,
Washington, DC

Profile summary

David was a Senior Partner in BCG's Washington, D.C. office and led its Energy Practice in North America. He was hired to build the practice. During his tenure, the practice grew over 35% a year and tripled its partnership. His personal client work focused on range of energy clients, with a primary focus on utilities. His areas of expertise include:

- Power generation strategy and operations
- Vertically integrated utilities including T&D
- Renewables and distributed energy resources
- He has also worked across all other parts of the energy value chain, e.g. oil & gas exploration and production, gas/midstream, oilfield services, refining and downstream operations, EPC
- He worked on a range of efforts including corporate and business unit strategy, operations, and transformation and organization

Prior experience and education

David has also had a long operating career at AES Corporation, PG&E Corporation, and Baker Hughes with responsibilities, which included:

- P&L for 13,000MW of generation capacity where he formulated and led a major process driven improvement program that reduced EFOR by ~50%
- Chairman of Indianapolis Power and Light, a vertically integrated utility
- Member of AES Executive Office which oversees AES' global business strategies and approves significant projects and development spending
- Served on a number of outside Boards of Directors, including C&D Technologies (NYSE), Great Point Energy (a VC backed coal gasification startup) and Greenhouse Gas Services (an AES/GE JV)

Prior to BCG David was a Principal with McKinsey and Company where he led their US Refining and Petrochemicals practice. He holds a M.S. in Finance from the Sloan School of Business at MIT and a B.S. in Chemical Engineering with highest distinction from the University of Virginia.

FORM A

Proceeding:

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ....David Gee........(*name*). I live at 721 ShadyLake Lane..... (*city*), in the ....Vero Beach... (*province/state*) of ....Florida....... .

2. I have been engaged by or on behalf of ...Hydro One...... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ....7 May 2018....

Signature

1.1 ATTACHMENT 15: BCG REPORT – IMPLEMENTATION OF RECOMMENDATIONS

In its decision in EB-2016-0160, the OEB directed Hydro One to conduct a review of its investment planning process. Hydro One engaged the Boston Consulting Group ("BCG") to conduct that analysis. The BCG report is provided at Attachment 14 of TSP Section 1.4. The study was completed on March 13, 2018. The study confirms that overall, Hydro One has implemented a consistent, thorough planning process that meets or exceeds expectations for a typical utility planning process in all areas. BCG identified three areas for Hydro One to focus on, to continue its progress towards having a best in class planning process. A description of each recommendation, as well as, a summary of Hydro One's progress regarding the implementation of these recommendations is provided below.

<u>Investment Development:</u>

- Continue to clear the backlog in condition testing for critical assets, and ensure that steady state plans allow for ongoing condition data gathering as assets age.

<u>Asset Strategies:</u>

- Continue to ensure asset strategies are in place to guide investment development and updated to ensure relevancy.

<u>Outcomes Tracking:</u>

- Continue the implementation of plans to use performance data to enhance outcome forecasting capabilities.
- Set interim annual targets for scorecard metrics to facilitate tracking towards five year goals outlined in Hydro One's regulatory scorecard.

Investment Development

Hydro One's transmission assets are replaced as condition warrants through rigorous testing. However, a backlog of asset condition testing has developed for assets such as conductors and shieldwire, where a large portion of the asset base is approaching it's Expected Service Life ("ESL").

Hydro One is working to address the backlog of condition data for these assets through the use of the Kinectrics LineVue inspection system, which traverses along a transmission line span to assess shieldwire or conductor condition. Data collected is used to estimate the remaining service life of the asset without the need for an outage or intrusive testing. The tool allows for a greater number of condition assessments per year and is more cost efficient compared to removing conductor and shieldwire samples for laboratory testing. In 2018, the LineVue system was used to assess the condition of over 2000 circuit km of conductor and 2000 circuit km of shieldwire. As a result, over 7% of Hydro One's conductor fleet and 6% of Hydro One's shieldwire fleet was assessed for condition. Hydro One will continue to complete these condition assessments annually.

To mitigate risks to customer supply and system reliability, asset condition assessment is prioritized for all assets that have surpassed their assessment criteria. Hydro One will continue to prioritize condition assessment to ensure that the assets with the highest risk are tested first. This will maximize the risk mitigated within Hydro One's proposed spending envelope.

Asset Strategies

Hydro One has detailed strategy documents for its transmission assets. These strategies formally document life cycle management for each asset. The maintenance and replacement procedures outlined in the strategy documents are incorporated in the investments proposed in Hydro One's TSP. To ensure that the asset strategy documents are kept up-to-date and accurate, the strategies are regularly reviewed. Since the Prior Proceeding, Hydro One has reviewed and revised strategy documents for the majority of Transmission Lines, Stations and Protection & Automation assets. These are among the most critical assets in Hydro One's transmission system. To further strengthen Hydro One's asset management capabilities, the development of new strategy documents for minor assets is currently underway.

Outcomes Tracking

Guided by the BCG recommendations outlined in the Investment Planning Process Review, Hydro One implemented a new process step in 2018, which included an upfront identification of corporate strategic direction, the establishment of interim targeted outcomes and more granular, strategic budget allocations based on operational, financial, regulatory and customer considerations at the beginning of the investment planning process.

Hydro One conducted a strategic budget (capital/OM&A) allocation at the beginning of the process, whereby the plan was divided into smaller, discrete budgets based on business unit, and then investments were subsequently prioritized within those budgets. The basis for this upfront allocation was the expenditure levels included in the previous plan, adjusted for efficiency gains and new strategic directions, as illustrated in Figure 1 below. This was done by business unit, resulting in nine allocations.

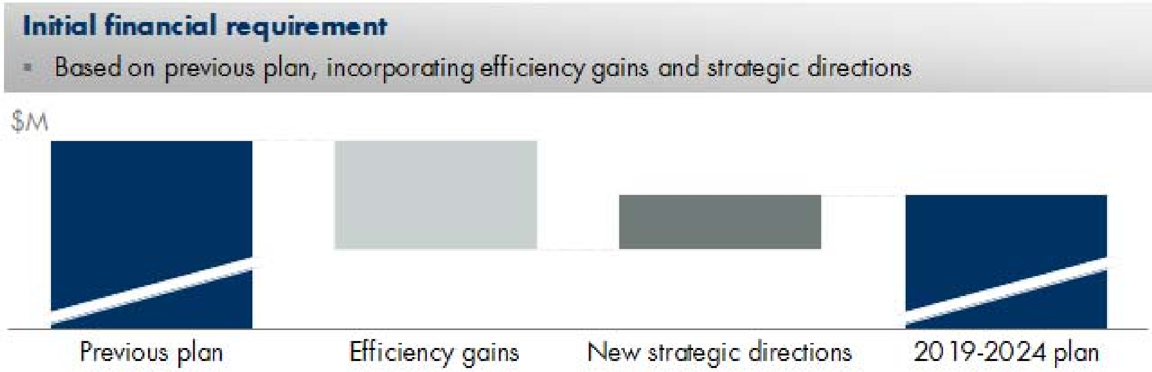


Figure 1 – Illustration of Initial Strategic Budget Allocation

The nine allocations are: Transmission Power Systems, Distribution Power Systems, System Operations, Facilities, Fleet, Information Solutions, Security, Customer Care and Health, Safety and Environment.

Along with each allocation, specific 6-year outcomes were identified. The outcomes relevant to Hydro One's Transmission Power Systems allocation are shown in Figure 2 below.

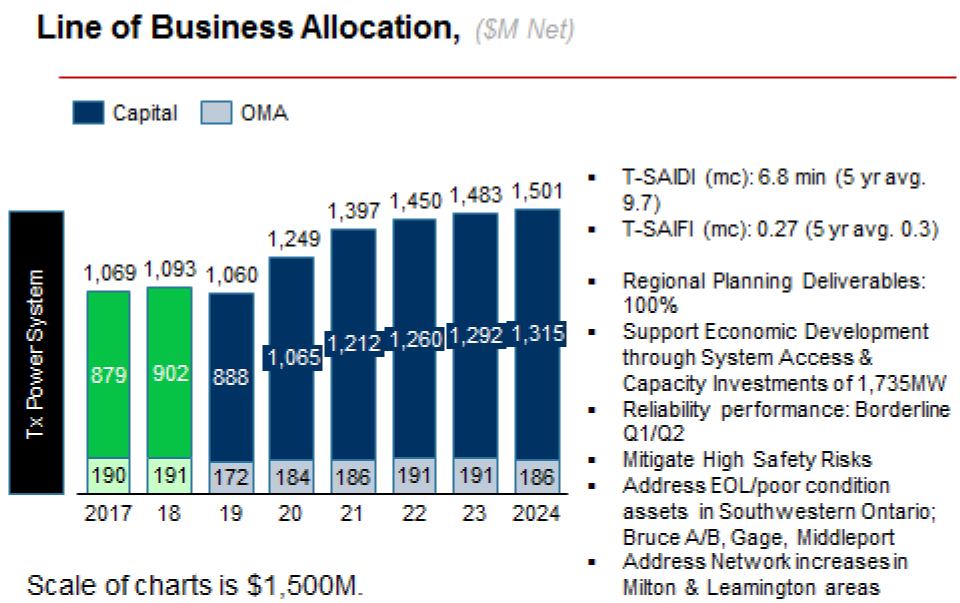


Figure 2 - Transmission Power System Outcomes

In addition to the end-of-plan outcomes, near-term, 1-year outcome metrics were identified, as outlined in Table 1 below. 1-year metrics were developed at the beginning of the Investment Planning Process and subsequently revised based on the approved plan, to form the various business unit scorecards that will be used for 2019. The establishment of interim targets supports the overall approach to long-term target setting and monitoring, ensuring that the long-term targets have updated targets annually.

Table 1 - 1-year Transmission Outcome Metrics

LOB	Initial 1-year Metrics
Transmission Power Systems	• Tx SAIDI (MC) - 8.7 minutes • Regional Infrastructure Planning Process Deliverables Met – 100%
System Operations	• Reliability of Service - 99.95% of key systems
Facilities	• Productivity Savings - $1M
Fleet	• Fleet Size – 7,200 asset count • Annual Utilization – 6.0M hours
Information Solutions	• Cost of Service - 4.5% of operating expenses • Reliability of Service – 99.53% critical system availability
Security	• Security Posture – Medium • NERC Compliance – 100%
Health, Safety and Environment	• Recordable rate - <1.0 incident per 200,000 hours

Through ongoing monitoring and analysis of the 2019 scorecard, Hydro One will be able to review the forecast to actual variance and use lessons learned to better inform future outcome forecasting.

Other Enhancement Opportunities

The BCG review noted other areas of improvement opportunity for Hydro One, including articulating the scope of the investment plan, improving consistency and objectivity of risk assessments, inclusion of execution feedback and mature cost estimates, plan execution and outcome tracking, and process timing. Hydro One has implemented the following improvements to address the various opportunities.

- **Define investment plan objectives – Scope of investment planning process defined & articulated:** Internally, Hydro One has stakeholdered and agreed to classification of expenditures between work program and corporate costs, based on the following definitions and characteristics:

Investment Plan (i.e. Work Program)	**Corporate Costs**
• All capital, consistent with SP0775 (Classification of Expenditures) is included in the investment plan • Directly related to the **sustainment, development and operation** of Hydro One's assets and systems • Typically "**direct**" costs associated with a specific cost object, such as a specific service, unit or activity (i.e. accomplishments), are included in the investment plan • Typically these costs are, to an extent, **variable** costs that vary in relation to the scope and volume of work planned.	• Provide shared **operational, strategic and/or policy support** to the organization • Typically "**indirect**" costs not associated with a specific cost object o **Administrative and general costs** / shared common services • Costs are allocated across multiple Hydro One entities (regulated and/or unregulated). • A portion of these costs may meet the criteria for capitalization through their support of the capital work program.

- **Establish criteria, score and calibrate – Risks calibrated consistently** - Hydro One undertook a new approach to bring about more consistency and remove subjectivity with investment scoring through a dedicated team which discussed and scored all of the investments collaboratively, leveraging other subject matter experts, on an as needed basis. This was done for Transmission Power Systems and Distribution Power Systems. This approach improved the consistency of risk assessments across asset disciplines, and provided an opportunity to conduct a quality assurance ("QA") review in parallel with scoring. The other business unit allocations held similar review sessions for investment calibration and QA.

- **Establish criteria, score and calibrate – Investments evaluated against risk criteria** - The Investment Planning process now involves the Execution

Organizations at the calibration stage, which is far earlier in the process than before. Participation earlier in the process provides greater visibility and puts the Executing Organizations in a better position to provide feedback and input to the Investment Plans.

- **Develop investment plan options – Detailed estimates included for initial plan timeframe** - As noted in B-02-01, a structured project stage gate process has been implemented, which requires projects to pass stage gates before moving to the next phase in the capital delivery process. Projects which pass stage gates are considered able to meet the schedule and cost outcomes presented within the estimate accuracy bands for the current level of project development.

- **Execute plan and track outcomes – Executed investments align to finalized investment plan** - The Investment Redirection Committee, as described in B-02-01, tracks the performance of the in-year work program against budget, which provides the operations leadership team an opportunity to understand month-to-month variances as well as the impacts on the annual budget and outcomes. Variances to capital expenditures, in-service additions and key accomplishment units are included in this monthly review.

- **Governance and oversight – Sufficient time and resources allocated to IPP -** Under steady state, all of the timing related issues identified in the BCG review will no longer be an issue.

KINECTRICS

HYDRO ONE – EXPECTED SERVICE LIFE ASSESSMENT OF RELAYS

ESL ASSESSMENT OF MCGG 22 & D60 RELAYS

K-814095-DOC-0001 R03

Prepared for

Hydro One Networks Inc.
Purchase Order # 4500258452

Issue Date

2019-Jan-31

Prepared by	Reviewed by	Approved by
Digitally signed by Arend Koert Date: 2019.01.31 21:33:30 -05'00'	Garreth Coelho Digitally signed by Garreth Coelho DN: cn=Garreth Coelho, o=Kinectrics Inc, ou=DAM, email=garreth.coelho@kinectrics.com, c=CA Date: 2019.02.01 10:32:57 -05'00'	Digitally signed by Dave Clarke Date: 2019.02.08 17:12:23 -05'00'
Signature	*Signature*	*Signature*
Arend Koert	Garreth Coelho	Dave Clarke
Principal Engineer	Business Area Director	Senior Vice President
Distribution & Asset Management	Distribution & Asset Management	T&D
Date prepared	Date reviewed	Date approved

Revision History

Rev	Description			
00	Original report			
	Issue Date	Prepared by	Reviewed by	Approved by
	2018-Mar-07	Arend Koert	Garreth Coelho	Dave Clarke
Rev	Description			
01	Inserted missing row in Table 4-4; added failure analysis of relay; edited Conclusions and Recommendations			
	Issue Date	Prepared by	Reviewed by	Approved by
	2018-Mar-28	Arend Koert	Garreth Coelho	Dave Clarke
Rev	Description			
02	Previous report was interim; final report for completed accelerated life testing work			
	Issue Date	Prepared by	Reviewed by	Approved by
	2018-Dec-19	Arend Koert	Garreth Coelho	Dave Clarke
Rev	Description			
03	Minor edits following feedback from HONI			
	Issue Date	Prepared by	Reviewed by	Approved by
	2019-Jan-31	Arend Koert	Garreth Coelho	Dave Clarke

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1 Introduction

HONI periodically submits rates filings to the Ontario Energy Board. These submissions *inter alia* detail HONI's key transmission asset needs based on asset age, condition assessment, performance and other relevant factors that lead to asset replacement/refurbishment. HONI has expressed a strong need for a third party to provide independent recommendations to help support their case to the Ontario Energy Board, particularly in the area of electromechanical, solid-state and digital/numerical relays – transmission station assets that play a critical role in ensuring safe and reliable operation of the transmission system. Historically, HONI has replaced 450 relays per year on average, where population age exceeding the expected service life (ESL) is the leading factor triggering analysis as to whether the population must be maintained for a further number of years or replaced.

Table 1-1 shows the breakdown of HONI's relay systems as at close of 2018, which excludes planned replacements for 2019. Solid-state relays carry the highest priority, as the age of 91% of this population of 2nd generation relays currently exceeds ESL; this represents 55% of HONI's total relay inventory that exceeds ESL (excluding planned replacements for 2019).

Table 1-1: Breakdown of HONI's Relay Systems (as at close of 2018)

	ESL [years]	**Average Age** [years]	**Age ≤ ESL**		**Age > ESL**		**Total**	
Electro-mech.	45	38.8	2,289	63%	1,322	37%	3,611	100%
Solid-state	25	35.3	191	9%	1,835	91%	2,026	100%
Digital/numerical	20	8.7	6,663	97%	206	3%	6,869	100%
Total		**27.6**	**9,501**		**3,363**		**12,506**	

↓

Age > ESL	
1,322	39%
1,835	55%
206	6%
3,363	**100%**

Moreover, in recent work completed by Kinectrics for CEATI, an ESL range of 13 to 19 years for solid-state relays emerged based on weighted utility survey and industry review results [2]. Similarly, a range of 13 to 20 years for digital/numerical relays emerged from the CEATI work. Indeed, HONI indicates that the traditional ESL figure of 25 years for digital/numerical relays is considered by some in industry to be overstated, with 17 years being more appropriate given that these relays reach obsolescence well before hardware reliability becomes a concern. Nevertheless, HONI is also concerned about the longevity of at least one of these digital/numerical relay models in its inventory, following reliability performance issues.

The main objective in this project was to assess the expected service life (ESL) for two relay models in HONI's inventory using accelerated life testing. The information from this assessment is to be used as an input by HONI asset managers for their asset life cycle strategy.

2 Scope

For the purposes of ESL assessment, HONI selected the relay models shown in Table 2-1 and provided samples of each – according to availability – as detailed in Table 2-2 and Table 2-3. The models were selected to represent the M series of solid state relays and the UR family of digital/numerical relays manufactured by GEC and GE respectively.

Table 2-1: Selected Relay Models

Model	Function	Technology	Manufacturer	Average Service Life [years]
MCGG 22	Overcurrent relay for phase and earth faults	Solid-state	GEC Measurements	20
D60	Line distance relay	Digital/numerical	GE	15

Table 2-2: MCGG 22 Relays (8 Units)

#	S/N
1	226952A
2	226980A
3	226951A
4	226960A
5	226962A
6	226977A
7	226989A
8	247306Y

Table 2-3: D60 Relays (5 Units)

#	S/N	Frame w/ Front Panel	Modules					
			Power RH	CPU 9D	CT-VT 8A	Digital I/O 6U	Digital I/O 4C MOD	Digital I/O 6T
1	MABC09000010	1	1	1	1	2	1	1
2	MABC12000162	1	1	1	1	2	1	1
3	MABC12000160	1	1	1	1	2	1	1
4	MABC13000090	1	1	1	1	5	-	-
5	MABC10000069	1	1	1	1	2	1	1
Totals		**5**	**5**	**5**	**5**	**13**	**4**	**4**

For the MCGG 22 relays, it is clear that the sample size is eight. For the D60 relays, faulty in-service modules would be replaced with spares and so reliability targets should be applied at module level; therefore, although the nominal sample size is five, it is as low as four and as high as 13 at module level.

The scope of work set out in Kinectrics quote Q418-015-KOE-HON-REV02, was as follows:

- For each selected relay model, determine reliability target and confidence level subject to sample size
- Ascertain component types / categories and their expected failure mechanisms via component-level analysis of one unit of each selected relay model to determine range of acceleration factors, and plan an appropriate test regime
- Conduct accelerated life test – pre-qualifying test, life-test cycles (including monitoring and post-cycle tests), post-life test – on units of the selected relay models
- Results analysis and reporting

In this report, an overview of reliability concepts and testing is first provided, followed by sections describing methodology, results, conclusions and recommendations.

3 Reliability Concepts and Testing – An Overview

A modern definition of reliability may be expressed as follows [3]:

> *"Reliability is the probability of a product performing its intended function over its specified period of usage, and under specified operating conditions, in a manner that meets or exceeds customer expectations."*

The following subsections describe some of the basic concepts used in reliability engineering [4] [5] [6].

3.1 Reliability metrics

The reliability of a population of like devices at time *t* may be expressed as:

$$R(t) = \frac{N(t)}{N_0}$$

where *N(t)* is the number of surviving devices at time *t* and N_0 is the starting population. Similarly, the population fraction failing by time *t* may be expressed as:

$$F(t) = \frac{N_0 - N(t)}{N_0} = 1 - \frac{N(t)}{N_0} = 1 - R(t)$$

and this is the cumulative distribution function (cdf). The probability density function (pdf) is defined as:

$$f(t) = \frac{dF(t)}{dt}$$

which corresponds to a histogram of the population lifetimes or times-to-failure (TTF). Then the instantaneous failure rate at time *t*, or hazard rate function, may be defined as:

$$h(t) = \frac{f(t)}{1 - F(t)} = \frac{f(t)}{R(t)}$$

and is a measure of “proneness” to failure [4] as a function of population age. Its integral is the cumulative hazard function:

$$H(t) = \int_{-\infty}^{t} h(\tau) d\tau$$

which is related to *R(t)* as follows:

$$R(t) = e^{-H(t)}$$

Finally, the mean life or mean-time-to-failure (MTTF) is defined as:

$$MTTF = E(TTF) = \int_{-\infty}^{\infty} t \cdot f(t)\, dt = \int_{-\infty}^{\infty} R(t)\, dt$$

where *E(TTF)* is the expectation (or mean or average) of the distribution but does *not* mean “anticipated life.” [4]

The above brief overview of reliability metrics provides the ground-work for further discussion.

3.2 Series-system model

Considering the complexity of a solid-state or digital/numerical relay, it is expected that they will have multiple, *M*, competing failure modes. Then, for simplicity, the reliability model of the device is a series system if its life is the smallest of the *M* potential times to failure, i.e., a device fails when the first failure mode occurs. This is also known as a “weakest link system”. Furthermore, if the *M* failure modes are statistically independent, then the product rule for reliability applies such that:

$$R(t) = R_1(t)R_2(t)\dots R_M(t) = e^{-H_1(t)}e^{-H_2(t)}\dots e^{-H_M(t)} = e^{-H(t)}$$

from which the following addition rule and its derivative are derived:

$$H(t) = H_1(t) + H_2(t) + \cdots + H_M(t)$$

$$h(t) = h_1(t) + h_2(t) + \cdots + h_M(t)$$

Finally, the composite probability density function (pdf) may then be expressed as:

$$f(t) = [h_1(t) + h_2(t) + \cdots + h_M(t)]R_1(t)R_2(t)\dots R_M(t)$$

In this work it is assumed that reliability models of relays are series systems and that the *M* failure modes are statistically independent.

3.3 Bathtub curve

Consider a large population of like devices with a <u>single</u> failure mode. Then the hazard rate may be expressed as a continuous Weibull function:

$$h(t) = \frac{\beta}{\eta}\left(\frac{t}{\eta}\right)^{\beta-1}$$

where η is the characteristic life – the time by which 63.2% of the population may be expected to fail due to the single failure mode – and β is the shape parameter, as follows:

- $\beta < 1$: Decreasing failure rate (DFR) due to design, manufacturing and component defects
- $\beta = 1$: Constant failure rate (CFR) due to random causes
- $\beta > 1$: Increasing failure rate (IFR) due to wear-out of components

According to the hazard rate addition rule, a composite Weibull hazard rate function – describing the bathtub curve – may be expressed, for multiple *M* competing failure modes, as:

$$h(t) = \sum_{\substack{j=1 \\ \beta_j<1}}^{K} \frac{\beta_j}{\eta_j}\left(\frac{t}{\eta_j}\right)^{\beta_j-1} + \sum_{\substack{j=K+1 \\ \beta_j=1}}^{L} \frac{\beta_j}{\eta_j}\left(\frac{t}{\eta_j}\right)^{\beta_j-1} + \sum_{\substack{j=L+1 \\ \beta_j>1}}^{M} \frac{\beta_j}{\eta_j}\left(\frac{t}{\eta_j}\right)^{\beta_j-1}$$

where $t \geq 0$. Note that the centre summation reduces to a simple sum of constant failure rates, i.e., $\lambda = \lambda_{K+1} + \lambda_{K+2} + \ldots + \lambda_L$, because $\beta_j = 1$. An example bathtub curve is shown in Figure 3-1.

Each of the *M* failure modes acts over the entire time-scale but is dominant in its respective region so that the hazard rate is approximately constant – at 0.25% per year in this example – within the "Mid-life" failure region, as shown in Figure 3-1.

For the bathtub curve shown in Figure 3-1, the associated probability density function (pdf), i.e., *f(t)*, and cumulative distribution function (cdf), i.e., *F(t)*, are shown respectively in Figure 3-2 and Figure 3-3 on the same scale, where the cdf is simply the area under the pdf as a function of *t*.

3.4 Expected service life (ESL)

The expected service life (ESL) of a large population of like devices is the statistical expectation (or prediction) of its actual end-of-life (EOL) or age at which the population must be reviewed or may reach the end of its useful life. The EOL may be defined in various ways:

- Population age at which the hazard rate – as per the "bath-tub" curve – exceeds (and continues to exceed) a predetermined threshold, e.g., 0.5% per year (see Figure 3-1)
- Population age at which the cumulative number of failed devices exceeds a predetermined percentage of the original population, e.g., 6% (see Figure 3-3)
- Population age at which the mean-time-to-failure (MTTF) of devices – since population inception – peaks and starts to fall off

Whereas the above may be monitored as the population ages, there is value in estimating EOL well before it is reached to allow planning and budgeting for replacement or refurbishment of the population.

3.5 Accelerated life testing

Accelerated life testing (ALT) may be employed to estimate EOL, where time-to-failure for each failure mode is accelerated by subjecting a sample from the population of like devices to elevated stress compared to normal use conditions.

For simplicity and validity, a single accelerating stress is recommended [7], and temperature is the most-often used overstress for electronic devices – such as solid-state relays and digital/numerical relays – as per the Arrhenius reaction rate model:

$$AF = \frac{TTF_U}{TTF_S} = exp\left[\frac{E_a}{k}\left(\frac{1}{T_U} - \frac{1}{T_S}\right)\right]$$

where *AF* is the life acceleration factor, *TTF* is time-to-failure, *T* is temperature in K, *k* is Boltzmann's constant (8.617×10^{-5} eV/K) and E_a is the activation energy (in the range 0.3 to 1.5 eV depending on component type and failure mode). Subscripts "U" and "S" refer respectively to normal-use and stress.

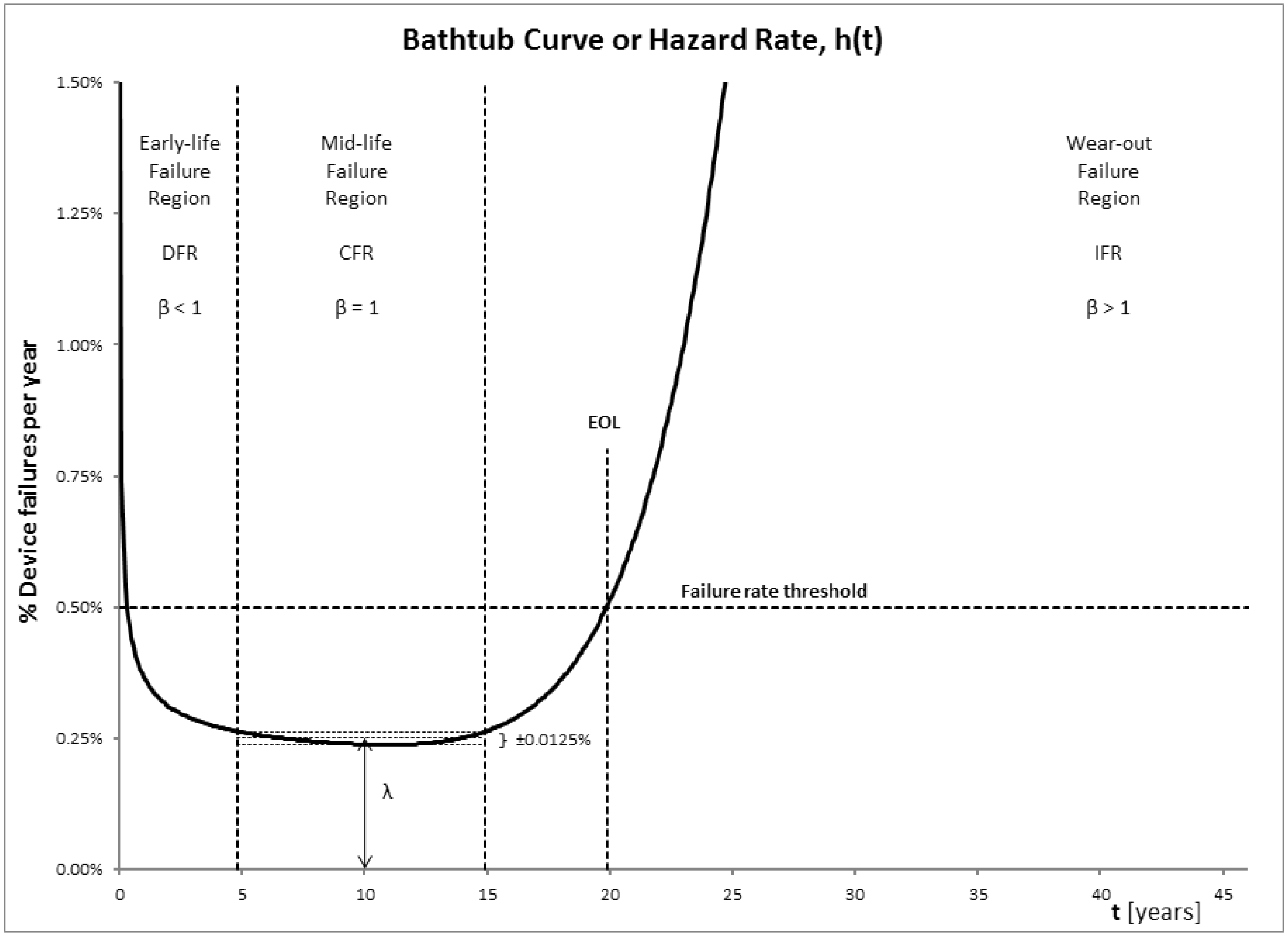

Figure 3-1: Hazard Rate "Bathtub" Curve

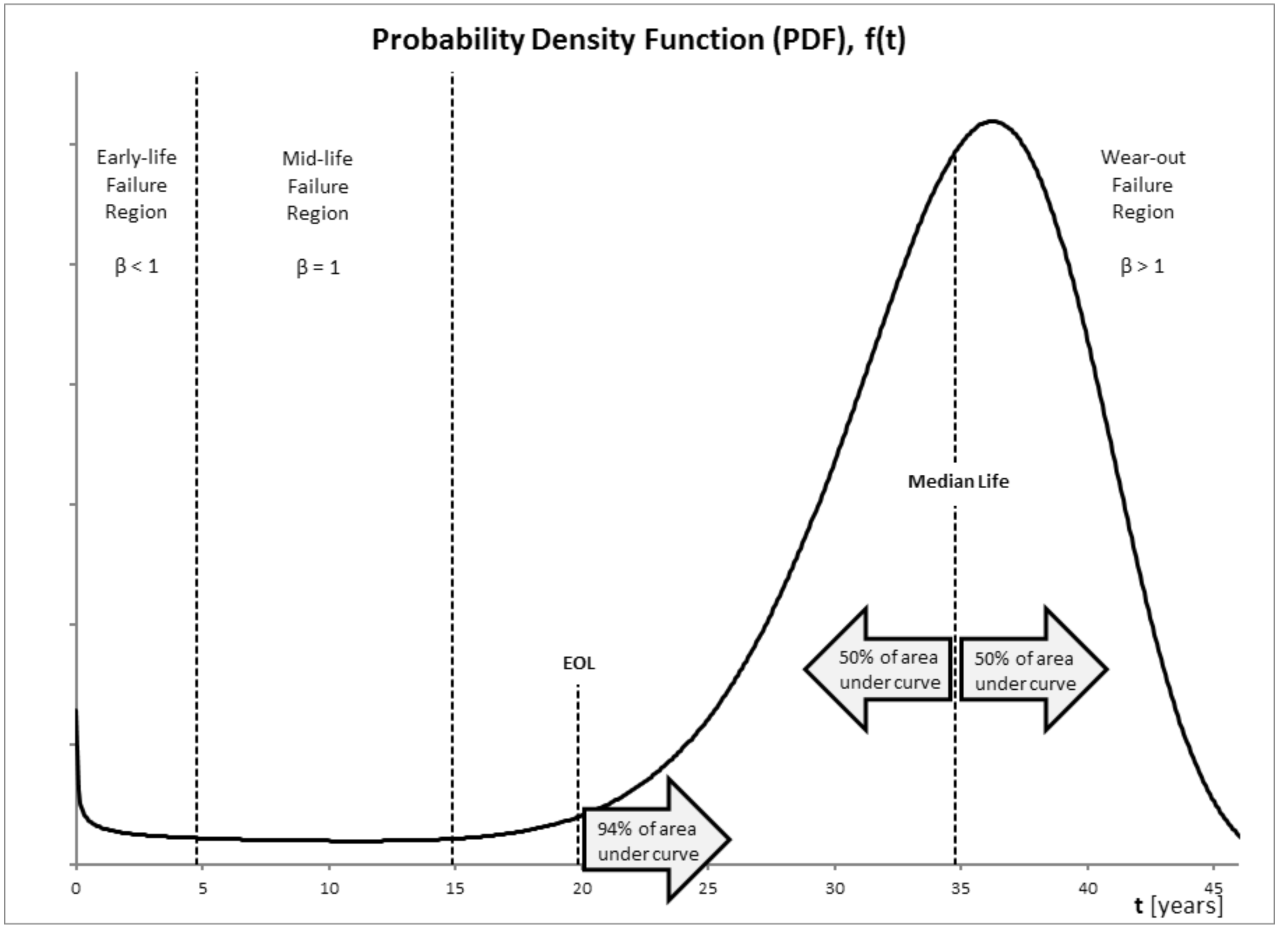

Figure 3-2: Probability Density Function (pdf)

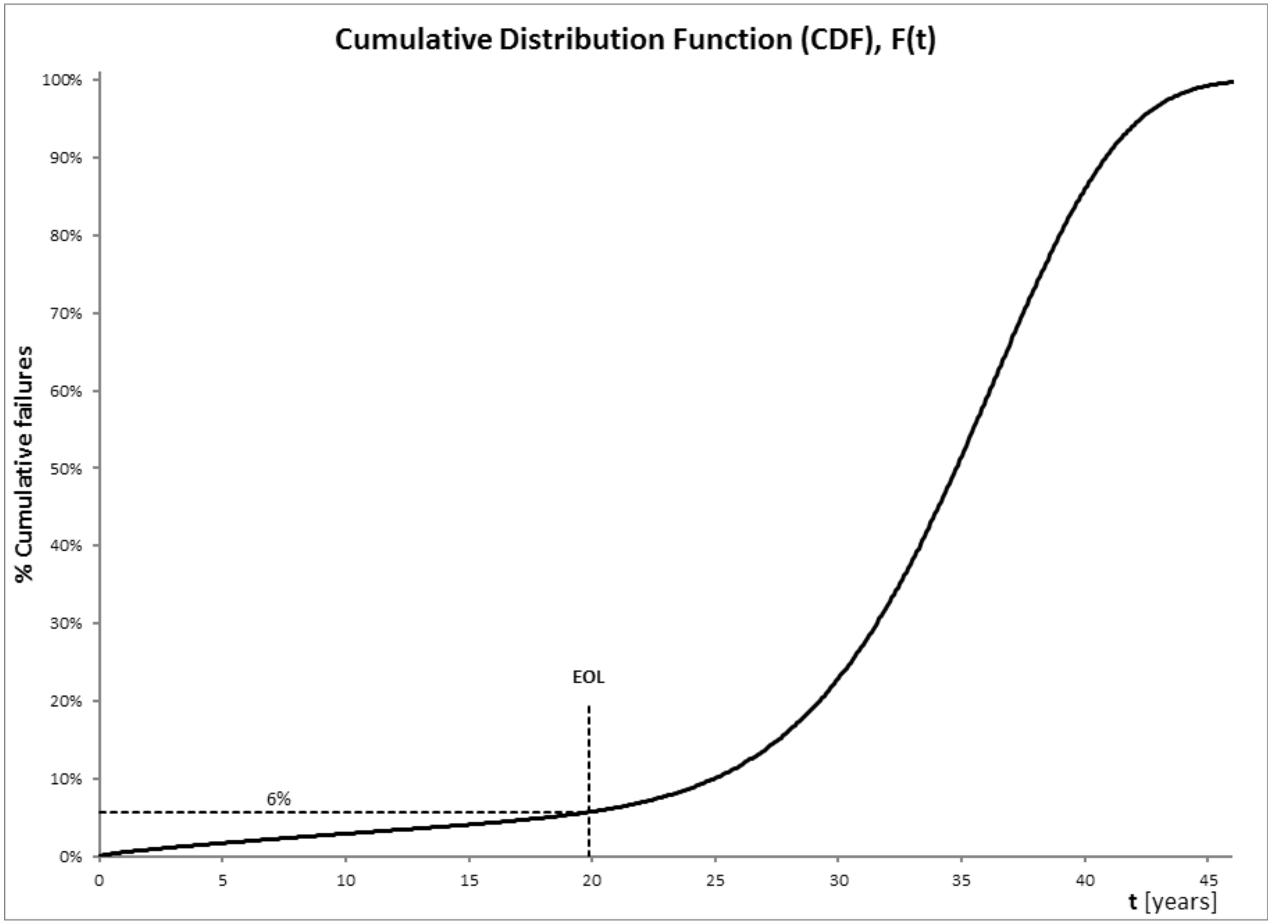

Figure 3-3: Cumulative Distribution Function (cdf)

It is important to note that each independent failure mode will have a different *AF*, as determined by E_a. In a typical accelerated life test, T_S is selected to be the maximum-allowable temperature as dictated by the component with the lowest temperature specification, e.g., 85 °C (+273), so as to prevent unrealistic component failure, and T_U is taken to be the average temperature for the population of devices, e.g., 24 °C (+273).

3.5.1 Ideal (parametric) approach

The net effect on the bathtub curve for the sample of devices is that the failure rate is amplified and the time-scale is compressed, and this must be "translated" to normal use conditions for each failure mode according to:

$$AF = \frac{\eta_U}{\eta_S}$$

under the assumption that β remains unchanged for each failure mode.

However, it is only possible to create a faithful copy of the bathtub curve for the population if:

- The sample comprises new devices
- The sample size is sufficiently large, i.e., ≥ 30 units, as per the Central Limit Theorem

The former is not a serious concern because the earlier part of the bathtub curve is not really required; the latter, however, is problematic due to the limited number of relays that can be made available for destructive testing.

3.5.2 Pragmatic (non-parametric) approach

In the non-parametric testing approach, the underlying failure distribution remains unknown. Suppose that 10 identical relays are subjected to an accelerated life test and two fail – same failure mode – by test time t_1. Then it can be stated that relay reliability under normal use conditions at time *AF* x t_1 is 8/10 or $R(AF \text{ x } t_1) = 0.8$, but this applies to the sample of relays only. Nevertheless, by using the cumulative binomial distribution that describes success/failure events, it is still possible to obtain a lower boundary on the reliability of the population of relays despite the underlying failure distribution being unknown. For instance, assuming a single-ended confidence C = 90%, the lower boundary on reliability at time *AF* x t_1 may be shown to be $R_L(AF \text{ x } t_1) = 0.55$ for the population of relays.

Now suppose that none of the 10 relays had failed by test time t_1. Then $R(AF \text{ x } t_1) = 1$ and, assuming a single-ended confidence C = 90%, the lower boundary on reliability under normal use conditions at time *AF* x t_1 may be shown to be $R_L(AF \text{ x } t_1) = 0.8$ for the population of relays. Therefore, a useful reliability metric can still be obtained for a greatly reduced sample size.

Furthermore, the lower boundary R_L may be used as a reliability target for the population of relays, such that the probability, that the reliability of the population of relays at time *AF* x t_1 is at least equal to the target reliability, is equal to the single-tailed confidence C. In reliability (probability) notation, this may be represented as follows:

$$Pr[R(AF \times t_1) \geq R_L] = C$$

The cumulative binomial distribution[1] governs the relationship between R_L, C, sample size and the number of allowable failures; this is shown in Table 3-1 for zero allowable failures – also referred to as *success testing*, which yields minimum sample sizes. As expected, minimum sample size increases with increasing R_L and/or C, and there is a trade-off between R_L and C for any given sample size.

Table 3-1: Minimum Sample Size as a Function of R_L and C

Minimum sample size (1)		Confidence level, C (2)				
		80%	85%	90%	95%	99%
Reliability target, R_L	0.7	5	6	7	9	13
	0.75	6	7	8	11	16
	0.8	7	9	10	13	21
	0.85	10	12	14	18	28
	0.9	15	18	22	28	44
	0.95	32	37	45	58	90
	0.99	160	189	229	298	458

Notes:

1) Required sample size for zero allowable failures by time t_1; larger sample sizes are required for non-zero allowable failures
2) Single-tailed confidence

The results, however, would have no bearing on EOL, unless it was known that the population age is approaching EOL. Then it is possible to assess the survival (reliability) of the population for the next *Y* years given that it has already survived *X* years, i.e., $R(Y|X)$ or:

$$Pr[R(AF \times t_1|X) \geq R_L] = C$$

[1] The F-distribution, i.e., Fisher-Snedecor distribution, gives the same results and is easier to use for success/failure calculations.

Note that this applies to each failure mode with its unique *AF*. Therefore, it is necessary to compile a bill of materials (BOM) for each relay model in order to categorise relay components – resistors types, capacitor types, semiconductors, integrated circuits, etc. – according to activation energy as per published values [8]. Then for each component category, the *AF* may be calculated to yield a t_1 milestone in the test at which it will reach its target life, i.e., $X + Y = X + AF \times t_1$. As each component category milestone is reached, the test is halted temporarily to check whether the test units are still functional. In case of component failure, if it has not met its target life according to component category, then zero allowable failures has been exceeded and the test is considered complete; otherwise, testing must continue until all component categories have reached the target life.

4 Test Preparation

4.1 Reliability target

Table 4-1 shows the chosen reliability targets with associated single-tailed confidence levels. It may be noted that the allowable number of failures, N_f, for the Digital I/O 6U modules is 2; this allows a consistent reliability target for the overall D60 relay despite the considerably larger sample size of the Digital I/O 6U modules.

Table 4-1: Reliability Target

Relay	Module	Sample Size	Reliability Target, R_L	Single-tailed Confidence, C	Allowable No. of Failures, N_f
MCGG 22	-	8	0.75	90%	0
D60	All except below	5	0.7	80%	0
	Digital I/O 6U	13	0.7	80%	2
	Digital I/O 4C MOD	4	~ 0.7	80%	0
	Digital I/O 6T	4	~ 0.7	80%	0

Moreover, given that the MCGG 22 and D60 relay populations are both within about five years of the deemed ESL of 25 and 20 years respectively, Y = 5 years was selected such that:

$$Pr[R(5|20) \geq\ 0.75] = 90\%$$

$$Pr[R(5|15) \geq\ 0.7] = 80\%$$

are the reliability targets in reliability (probability) notation for MCGG 22 and D60 relays respectively.

In other words, given the available sample of MCGG 22 relays, the goal of accelerated life testing in this project was to demonstrate that the reliability of HONI's population of MCGG 22 relays over the next five years is at least equal to a modest target of 0.75, with a probability of 90%.

Similarly, given the available sample of D60 relays, the goal of accelerated life testing in this project was to demonstrate that the reliability of HONI's population of D60 relays over the next five years is at least equal to a modest target of 0.7, with a probability of 80%.

4.2 Bill of materials

MCGG 22 relay #8 and D60 relay #5 were each disassembled to compile a bill of materials (BOM) for components affected by temperature [8], as summarised in Table 4-2.

Table 4-2: BOM Summary

Component Type	MCGG 22	D60
Resistors – metal film, wirewound, trimpot	64	891
Capacitors – ceramic, metallised polyester, tantalum, electrolytic, etc.	26	711
Semiconductors – switching, power & zener diodes, LED, transistor, FET, etc.	37	429
Integrated circuits – logic, opto-isolator, microcontroller, EEPROM, etc.	6	229
Miscellaneous – inductor, relay, transformer, LCD, etc.	6	112
Totals	**139**	**2,372**

The D60 relay is more than an order of magnitude more complex than the MCGG relay, which comprises only discrete components, whereas most of the components in the D60 are surface-mount devices (SMDs), which are more difficult to identify.

4.3 Test milestones

The operating manual for the D60 relays indicates a maximum operating temperature of 85 °C [9] but the operating manual for the MCGG 22 relays is mute on this [10]. For the latter, data sheets for components listed in the BOM were consulted and it was found that one of the integrated circuits had a maximum operating temperature of 70 °C. Therefore, the MCGG 22 and D60 relays had to be placed in separate ovens.

The average operating temperature during normal use was deemed to be 24 °C [11] and, aided by component data sheets, an activation energy, E_a, value was obtained for each of the component categories [8] in the relay models. Using the Arrhenius reaction rate equation, an acceleration factor, AF, was calculated for each component category, allowing the required heat-soak for Y = 5 years to be calculated in each case. This is shown in descending AF order in Table 4-3 and Table 4-4 for the respective relay models.

Table 4-3: Required and Rationalised Heat-soak Periods for MCGG 22

Component Category	AF @ 70 °C	Required Heat Soak for Y = 5 years		Heat-Soak		
		Per category [months]	Increment [months]	Period	Duration [months]	Cumulative Test Length [months]
Aluminium electrolytic capacitor	21.3	2.8	2.8	1	2.9	2.9
LED	20.4	2.9	0.1			
Metallised polyester capacitor	14.2	4.2	1.3	2	1.3	4.2
Zener diode, transistor, various ICs	6.6	9.1	4.9	3	5.3	9.5
Switching diode, rectifier diode	6.4	9.4	0.3			
Ceramic capacitor	6.3	9.5	0.1			
Resistors	2.9	20.7	11.2	4	11.2	20.7
Relays	2.5	24.0	3.3	5	3.3	24.0
Inductors, transformers	1.6	37.5	13.5	6	13.5	37.5

Table 4-4: Required and Rationalised Heat-soak Periods for D60

Component Category	AF @ 85 °C	Required Heat Soak for Y = 5 years		Heat-Soak		
		Per category [months]	Increment [months]	Period	Duration [months]	Cumulative Test Length [months]
Aluminium electrolytic capacitor	58.3	1.0	1.0	1	1.0	1.0
LED, LCD	46.5	1.3	0.3	2	1.2	2.2
Metallised polyester capacitor	32.4	1.9	0.6			
EEPROM, CPLD	26.8	2.2	0.3			
Opto-coupler	19.2	3.1	0.9	3	1.2	3.4
Tantalum capacitor	17.6	3.4	0.3			
Zener diode, transistor, various ICs	12.6	4.8	1.4	4	1.4	4.8
Switching diode, rectifier diode	10.6	5.7	0.9	5	1.0	5.8
Ceramic capacitor	10.3	5.8	0.1			
Resistors	4.1	14.6	8.8	6	8.8	14.6
Relays	3.2	18.8	4.2	7	4.2	18.8
Inductors, transformers, chokes	2.4	25.0	6.2	8	6.2	25.0

Clearly, in an accelerated life test, the aluminium electrolytic capacitor component category will reach *Y* = 5 years before the LED/LCD component category, and so on. For both MCGG 22 and D60 models, the required heat soak for resistors, relays, inductors, transformers and chokes is considerably longer than that for other component categories – and therefore impractical; however, the need for any subsequent heat soaking depends on whether the target reliability has been met at that point.

For testing efficiency, increments less than one month were combined with other increments, resulting in the rationalised heat-soak periods shown at right in the tables. Note that the LED/LCD component category for the D60 relays was not combined with the aluminium electrolytic capacitor component category, because it was deemed more important to detect failure of the latter within its accelerated 5-year period. Provision was made for three and five heat-soak periods respectively for the MCGG 22 and D60 models.

Prior to any heat-soaking, all relays were subjected to functional performance testing to confirm that the relays were in working order and operating within specification (refer to Appendix B and Appendix C for extracts from Omicron test set).

In order to avoid thermal shock to the relays, each heat-soak period commenced with the oven ramping up to test temperature at a rate of 20 °C/hour and ended with the oven ramping down to ambient temperature at a rate of 20 °C/hour. Different ovens were used according to availability for both relay models. Figure 4-1 and Figure 4-2 show the MCGG 22 and D60 relays installed in their respective ovens. Throughout the heat-soak periods the MCGG 22 relays and D60 relays were powered by 110 Vdc and 120 Vac respectively.

Figure 4-1: MCGG 22 Relays in Oven

Figure 4-2: D60 Relays in Oven

At the end of each heat-soak period, the relays were subjected to functional performance testing to confirm that they were in working order and operating within specification, with decision points applied as follows:

MCGG 22 relays

Decision Point:
IF number of relevant failures > N_f THEN
R(5|20) < 0.75 with 90% confidence, i.e., reliability target is <u>not</u> met for further 5 years
GOTO Final Analysis and Test Report
ELSE
GOTO Next Heat-soak Period
END IF

Note: N_f = 0 based on sample size of eight; a relevant failure is the failure of a component before it has aged a further 5 years through accelerated life testing.

D60 relays

Decision Point:
IF number of relevant failures > N_f THEN
R(5|15) < 0.7 with 80% confidence, i.e., reliability target is not met for further 5 years
GOTO Final Analysis and Test Report
ELSE
GOTO Next Heat-soak Period
END IF

Notes: N_f depends on the applicable module; a relevant failure is the failure of a component before it has aged a further 5 years through accelerated life testing.

5 MCGG 22 Test Results

The sample of eight MCGG 22 relays completed Heat-soak Period 1 (HP1) without failure, whereas a miniature relay failure (within one of the relays) occurred during HP2. However, it is understood that the type of failure – as discussed further below – is atypical and may therefore not be relevant. Nevertheless, in order to err on the side of caution, it was decided by HONI and Kinectrics to supplement the eight relays with another six relays (refer to Table 5-1), so as to allow for one relay failure, i.e., N_f = 1, for an unchanged reliability target.

Table 5-1: MCGG 22 Relays – Supplemental (6 Units)

#	S/N
9	226991A
10	226945A
11	226946A
12	226958A
13	226990A
14	226978A

Whilst the original eight relays were subjected to HP3, the six supplemental relays were subjected to HP1, HP2 and a portion of HP3. The following subsections discuss the results for the combined sample of 14 units for each heat-soak period.

5.1 Heat-soak period 1: 3.0 months (14 units)

At the end of this heat-soak period, all relays were found to be in working order and operating according to specification. Therefore, the aluminium electrolytic capacitors and LEDs in the 14 units have reached the target 25 years without failure.

5.2 Heat-soak period 2: 1.3 months (14 units)

At the end of this heat-soak period, all relays (except Relay #5) were found to be in working order and operating according to specification. For Relay #5, the “phase-fault time-delayed trip output” was found to be faulty. The relay was disassembled and subjected to component analysis, which revealed that the coil of miniature relay RL1 (refer to Figure 5-1) was open-circuited. Its drive circuitry (free-wheeling diode D9, pnp transistor TR3, bias resistor R2 and emitter diode D2) were all inspected/tested and found to be in good working order, confirming that the failure of the miniature relay was not part of a chain of failure events.

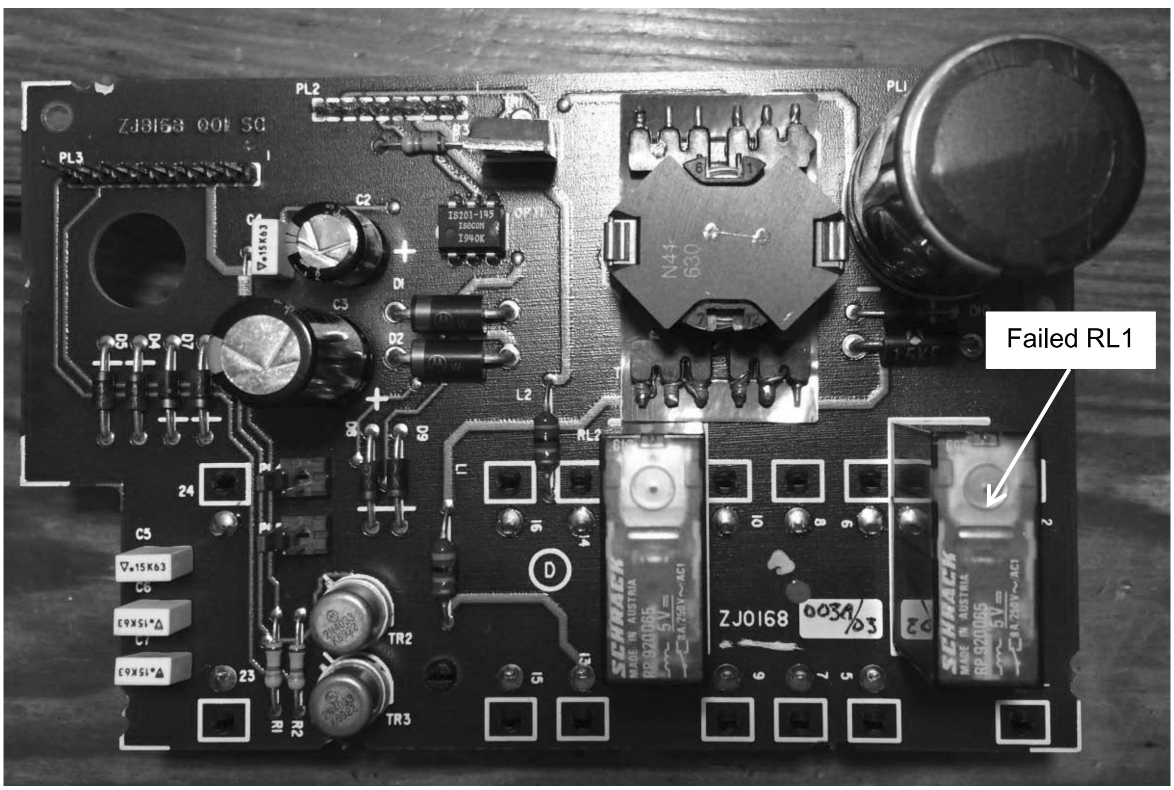

Figure 5-1: PSIO Board with Faulty Miniature Relay RL1

Miniature relay RL1 was de-soldered from the printed circuit board and carefully dissected using a cutting wheel. Via microscopic analysis, the magnet wire was found to be fractured right at the solder joint on the terminal, and it was confirmed that the coil itself was undamaged. Further analysis of the failure site, including scanning electron microscopy (SEM), would be required to ascertain the probable failure cause.

With modest *AF* = 2.5, miniature relay RL1 failed within the range[2] 20.6 to 20.9 years, which is significantly shorter than the target 25 years. However, as mentioned above, this type of failure is considered atypical and may not be relevant. Moreover, based on the sample of 14 relays, the single failure (thus far) of this type is acceptable in terms of target reliability.

Otherwise, the metallised polyester capacitors in the 14 units have reached the target 25 years without failure.

5.3 Heat-soak period 3: 5.4 months (8 units)

At the end of this heat-soak period, all relays (except Relay #3) were found to be in working order and operating according to specification. For Relay #3, some relay settings (via dip switches on the front panel) could not be achieved. The relay was opened and the continuity of each of 22 dip switches was checked in the open and closed states using a digital multimeter. In one case, the continuity value was the same whether open or closed until toggling greatly reduced the "closed" value in line with neighboring switches, and in another, toggling substantially reduced the "closed" value in line with neighbouring switches; both point to oxidation of switch contacts. The relay was retested and found to be in working order.

Otherwise, the zener diodes, transistors, various integrated circuits, switching diodes, rectifier diodes and ceramic capacitors in the eight units have reached the target 25 years without failure.

Note: By the end of HP3 for the original eight units, HP3 for the six supplemental units was only 18.5% complete. These units were also found to be in working order and operating according to specification. Therefore, pending any further accelerated life testing of the six supplemental units to complete HP3, no further consideration is required, i.e., the decision pertaining to HP3 is currently dependent on the original eight units only.

6 D60 Test Results

6.1 Heat-soak period 1: 1.0 month (5 units)

At the end of this heat-soak period, all relays were found to be in working order and operating according to specification. It was noted that darkening of the dot matrix LCD had occurred (refer to Figure 6-1); this is typical for LCDs subjected to high heat, and was therefore not considered relevant.

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[2] 20 + 2.5 x 2.9/12 = 20.6 and 20.6 + 2.5 x 1.3/12 = 20.9

Figure 6-1: Example of Darkening of D60 LCD

Otherwise, the aluminium electrolytic capacitors have reached the target 20 years without failure.

6.2 Heat-soak period 2: 1.2 months (5 units)

At the end of this heat-soak period, all relays were found to be in working order and operating according to specification. Therefore, the LEDs, LCDs, metallised polyester capacitors, EEPROMs and CPLDs have reached the target 20 years without failure.

6.3 Heat-soak period 3: 1.2 months (5 units)

At the end of this heat-soak period, all relays were found to be in working order and operating according to specification. Therefore, the opto-couplers and tantalum capacitors have reached the target 20 years without failure.

6.4 Heat-soak period 4: 1.4 months (5 units)

At the end of this heat-soak period, all relays were found to be in working order and operating according to specification. Therefore, the zener diodes, transistors and various integrated circuits have reached the target 20 years without failure.

6.5 Heat-soak period 5: 1.0 month (5 units)

At the end of this heat-soak period, all relays were found to be in working order and operating according to specification. Therefore, the switching diodes, rectifier diodes and ceramic capacitors have reached the target 20 years without failure.

7 Analysis

7.1 MCGG 22 relays

Figure 7-1 (overleaf) shows an overview of the ALT conducted on the MCGG 22 relays, where it is evident that six out of the nine component categories, or 67%, exceeded 25 years by the end of the test. The six component categories contain 69 out of a total of 139 components, or 49.6%. For the remaining three component categories representing the remaining 70 components, many more months of heat-soaking would be required – refer to Table 4-3 – to age these to 25 years. Also shown on the chart is a single failure of a miniature relay that occurred during HP2.

Recall from Section 4.1 that the project sought to demonstrate that the reliability of HONI's population of MCGG 22 relays over the next five years is at least equal to a modest target of 0.75, with a probability of 90%. Table 7-1 shows that this was exceeded for the first six component categories.

Table 7-1: Reliability Target Decision for MCGG 22 Relays

Component Category	Sample Size	Age Reached [years]	Allowable No. of Failures	No. of Failures	Reliability Target Decision
			on or before 25 years		
Aluminium electrolytic capacitor	14	> 25	1	0	Exceeded
LED	14	> 25	1	0	Exceeded
Metallised polyester capacitor	14	> 25	1	0	Exceeded
Zener diode, transistor, various ICs	8	> 25	0	0	Exceeded
Switching diode, rectifier diode	8	> 25	0	0	Exceeded
Ceramic capacitor	8	> 25	0	0	Exceeded
Resistors	14	< 25	1	0	Inconclusive
Relays	14	< 25	1	1	Inconclusive
Inductors, transformers	14	< 25	1	0	Inconclusive

However, for resistors, relays and inductors/transformers, the reliability target decision remains inconclusive until these have also reached an effective age of 25 years. Therefore, pending further accelerated life testing, it may be stated for HONI's population of MCGG 22 relays that:

$$Pr[R(Y|20) \geq 0.75] = 90\%$$

where Y is 2.3, 2.0 and 1.3 years respectively for resistors, relays (miniature) and inductors / transformers.

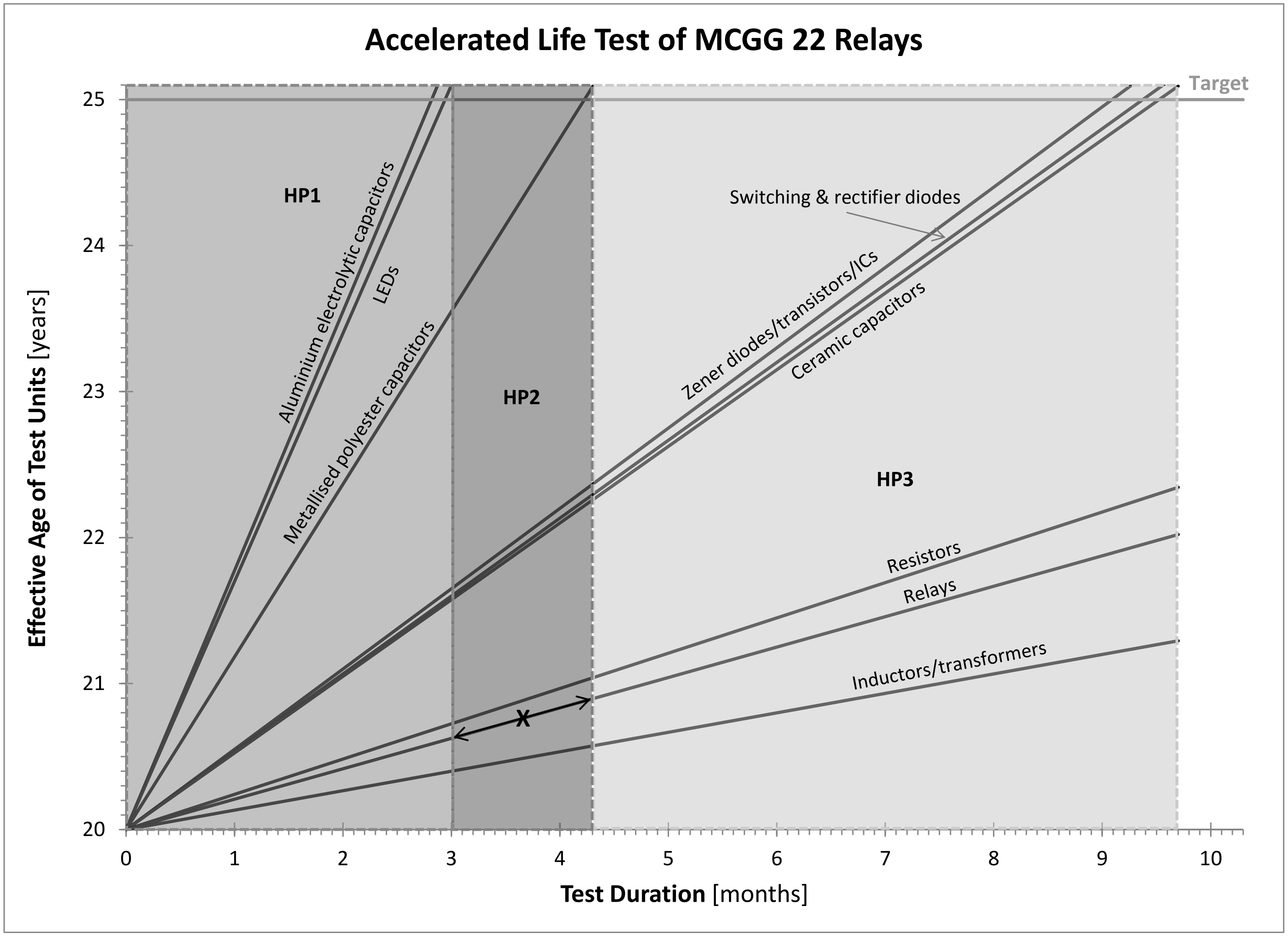

Figure 7-1: ALT Overview – MCGG 22 Relays

7.2 D60 relays

Figure 7-2 (overleaf) shows an overview of the ALT conducted on the D60 relays, where it is evident that nine out of the 12 component categories, or 75%, exceeded 20 years by the end of the test. The nine component categories contain 1,400 out of a total of 2,416 components, or 57.9%. (Note that these are average component numbers, as one of the five D60 relays had a different module configuration – refer to Table 2-3 – thereby resulting in different sample sizes at module level, as well as small differences in component category lists). For the remaining three component categories representing the remaining 1,016 components, many more months of heat-soaking would be required – refer to Table 4-4 – to age these to 25 years.

Recall from Section 4.1 that the project sought to demonstrate that the reliability of HONI's population of D60 relays over the next five years is at least equal to a modest target of 0.7, with a probability of 80%. Differentiating according to sample size, Table 7-2 to Table 7-4 each shows the applicable component category list and provides an indication of reliability target decision.

Table 7-2: Reliability Target Decision for D60 Relays – Front Panel and Standard Modules

Component Category	Sample Size	Age Reached [years]	Allowable No. of Failures	No. of Failures	Reliability Target Decision
			on or before 20 years		
Aluminium electrolytic capacitor	5	> 20	0	0	Exceeded
LED, LCD	5	> 20	0	0	Exceeded
Metallised polyester capacitor	5	> 20	0	0	Exceeded
EEPROM, CPLD	5	> 20	0	0	Exceeded
Opto-coupler	5	> 20	0	0	Exceeded
Tantalum capacitor	5	> 20	0	0	Exceeded
Zener diode, transistor, various ICs	5	> 20	0	0	Exceeded
Switching diode, rectifier diode	5	> 20	0	0	Exceeded
Ceramic capacitor	5	> 20	0	0	Exceeded
Resistors	5	< 20	0	0	Inconclusive
Relays	5	< 20	0	0	Inconclusive
Inductors, transformers, chokes	5	< 20	0	0	Inconclusive

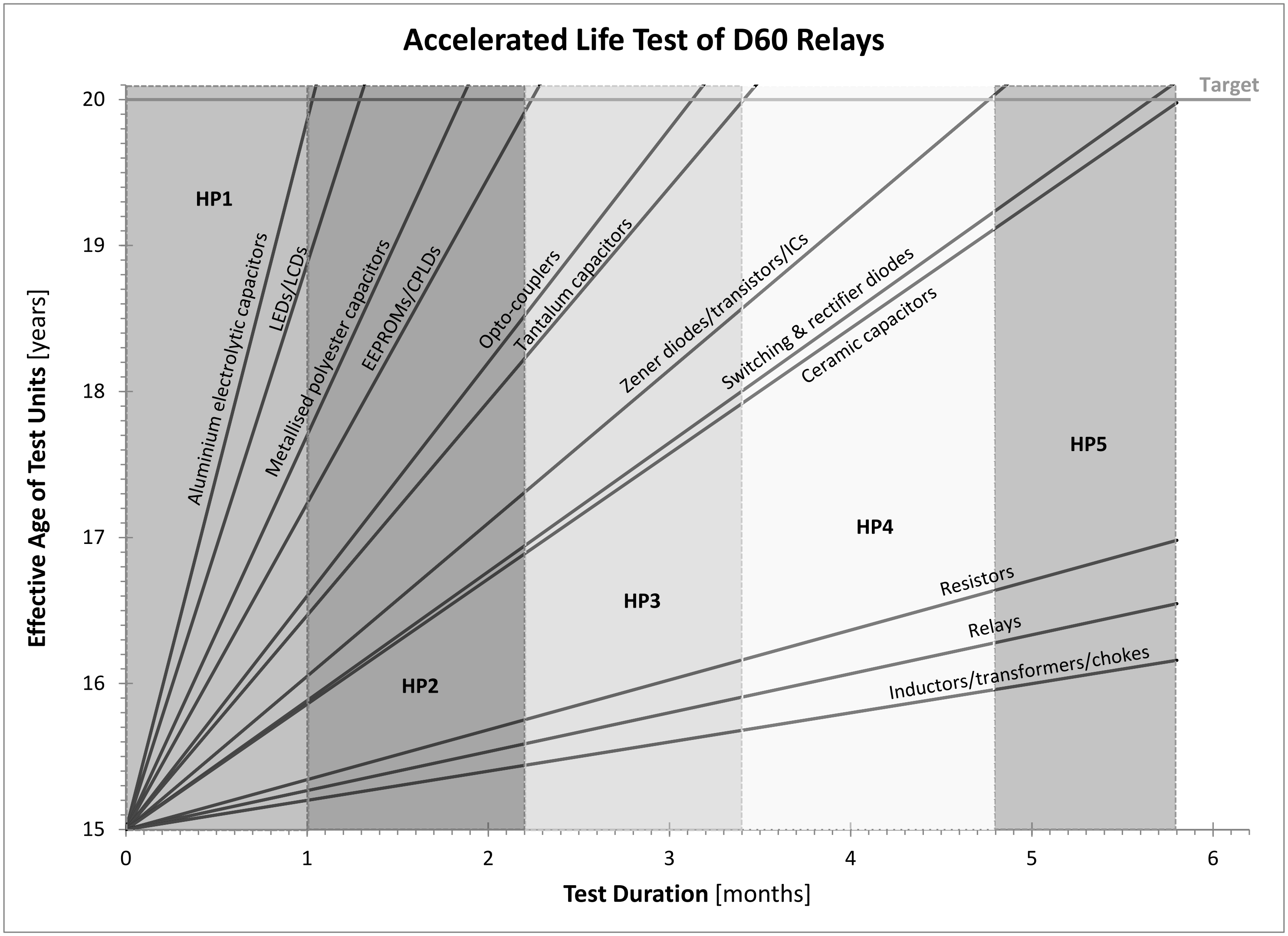

Figure 7-2: ALT Overview – D60 Relays

Table 7-3: Reliability Target Decision for Digital I/O 6U Module

Component Category	Sample Size	Age Reached [years]	Allowable No. of Failures	No. of Failures	Reliability Target Decision
			on or before 20 years		
Aluminium electrolytic capacitor	13	> 20	2	0	Exceeded
EEPROM, CPLD	13	> 20	2	0	Exceeded
Opto-coupler	13	> 20	2	0	Exceeded
Tantalum capacitor	13	> 20	2	0	Exceeded
Zener diode, transistor, various ICs	13	> 20	2	0	Exceeded
Switching diode, rectifier diode	13	> 20	2	0	Exceeded
Ceramic capacitor	13	> 20	2	0	Exceeded
Resistors	13	< 20	2	0	Inconclusive
Relays	13	< 20	2	0	Inconclusive
Inductors, transformers, chokes	13	< 20	2	0	Inconclusive

Table 7-4: Reliability Target Decision for Digital I/O 4C MOD and Digital I/O 6T Modules

Component Category	Sample Size	Age Reached [years]	Allowable No. of Failures	No. of Failures	Reliability Target Decision
			on or before 20 years		
Aluminium electrolytic capacitor	4	> 20	0	0	Exceeded
EEPROM, CPLD	4	> 20	0	0	Exceeded
Opto-coupler	4	> 20	0	0	Exceeded
Tantalum capacitor	4	> 20	0	0	Exceeded
Zener diode, transistor, various ICs	4	> 20	0	0	Exceeded
Switching diode, rectifier diode	4	> 20	0	0	Exceeded
Ceramic capacitor	4	> 20	0	0	Exceeded
Resistors	4	< 20	0	0	Inconclusive
Relays	4	< 20	0	0	Inconclusive
Inductors, transformers, chokes	4	< 20	0	0	Inconclusive

In summary:

- Front Panel and Standard modules – the reliability target was exceeded for the first nine (out of 12) component categories
- Digital I/O 6U Module – the reliability target was exceeded for the first seven (out of 10) component categories
- Digital I/O 4C MOD Module and Digital I/O 6T Module – the reliability target was exceeded for the first seven (out of 10) component categories

In all cases, for resistors, relays and inductors/transformers/chokes, the reliability target decision remains inconclusive until these have also reached an effective age of 20 years. Therefore, pending further accelerated life testing, it may be stated for HONI's population of D60 relays that:

$$Pr[R(Y|15) \geq 0.7] = 80\%$$

where *Y* is 2.0, 1.5 and 1.2 years respectively for resistors, relays and inductors / transformers / chokes.

8 Conclusions

HONI requested Kinectrics to assess the expected service life (ESL) of two of its relay populations for the purposes of asset replacement/refurbishment needs relating to its rates-filing submission to the Ontario Energy Board. The table below shows the relay models forming part of this assessment.

Model	Function	Technology	Manufacturer	**Average Service Life** [years]	**Deemed ESL** [years]
MCGG 22	Overcurrent relay for phase and earth faults	Solid-state	GEC Measurements	20	25
D60	Line distance relay	Digital/numerical	GE	15	20

Given that the average service life for both relay models is within about five years of deemed ESL and that only a small sample of relays could be provided per model, Kinectrics suggested non-parametric, elevated-temperature accelerated life testing, coupled with a modest reliability target and associated single-tailed confidence for each population of relays over the next five years.

As the acceleration factor varies according to component category, as well as stress temperature, one of each relay model was disassembled to compile a bill-of-materials (BOM) so that appropriate activation energy values could be assigned to each component category. This revealed further that separate ovens were required due to maximum operating temperature of 70 °C and 85 °C for the MCGG 22 and D60 relays respectively.

A number of heat-soak periods were designated for each relay model to allow successive component categories to reach 5 accelerated years. Between the heat-soak periods, the relays were subjected to functional performance testing to confirm that the relays were in working order and operating within specification. Then, if the number of relevant failures (of a particular component type) exceeded the maximum allowed within the 5 accelerated years for the particular component type, then the relay was considered not to have met the reliability target. Otherwise, the test remained inconclusive, requiring further heat-soak testing.

8.1 MCGG 22 relays

A sample of MCGG 22 relays was subjected to three heat-soak periods totalling 9.7 months. One relay experienced a miniature relay failure during the second heat-soak period. However, it is considered atypical and may therefore not be relevant. Moreover, the sample size allowed for the occurrence of one failure without affecting the reliability target. For HONI's population of MCGG 22 relays, the following was demonstrated:

a) For all components except resistors, relays (miniature) and inductors/transformers, the set reliability target:

$$Pr[R(5|20) \geq\ 0.75] = 90\%$$

was exceeded. In other words, it was demonstrated that in terms of all components except resistors, relays (miniature) and inductors/transformers, given an average age of 20 years, the reliability of HONI's population of MCGG 22 relays over the next five years is at least equal to 0.75, with a probability of 90%.

This may indicate that the deemed ESL is too pessimistic, i.e., that actual ESL lies somewhat beyond 25 years.

b) For resistors, relays (miniature) and inductors/transformers, the reliability target decision remains inconclusive because these components have not yet reached an effective age of 25 years. Therefore, pending further accelerated life testing, it may be stated for these components that:

$$Pr[R(Y|20) \geq\ 0.75] = 90\%$$

where *Y* is 2.3, 2.0 and 1.3 years respectively for resistors, relays (miniature) and inductors / transformers.

8.2 D60 relays

A sample of D60 relays was subjected to five heat-soak periods totalling 5.8 months. None of the relays experienced failure during the heat-soak periods. For HONI's population of D60 relays, the following was demonstrated:

a) For all components except resistors, relays (miniature) and inductors / transformers / chokes, the set reliability target:

$$Pr[R(5|15) \geq 0.7] = 80\%$$

was exceeded. In other words, it was demonstrated that in terms of all components except resistors, relays (miniature) and inductors/transformers/chokes, given an average age of 15 years, the reliability of HONI's population of D60 relays over the next five years is at least equal to 0.7, with a probability of 80%.

This may indicate that the deemed ESL is too pessimistic, i.e., that actual ESL lies somewhat beyond 20 years.

b) For resistors, relays (miniature) and inductors/transformers/chokes, the reliability target decision remains inconclusive because these components have not yet reached an effective age of 20 years. Therefore, pending further accelerated life testing, it may be stated for these components that:

$$Pr[R(Y|15) \geq 0.7] = 80\%$$

where *Y* is 2.0, 1.5 and 1.2 years respectively for resistors, relays (miniature) and inductors / transformers / chokes.

9 Recommendations

Whereas continued heat-soak testing of both MCGG 22 and D60 relays appears to be recommended for the sake of demonstrating the set reliability target pertaining to resistors, relays (miniature) and inductors/transformers/chokes, the remaining heat-soak periods are quite excessive, totalling 27.8 and 19.2 months respectively for MCGG 22 and D60 relays. Moreover, during these heat-soak periods, it is likely that numerous failures will start to occur for other component categories (with larger acceleration factors).

Otherwise, it is recommended that HONI review the deemed ESL values of 25 and 20 years respectively for the MCGG 22 and D60 relays, as they appear to be too pessimistic.

10 Acknowledgements

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- Miroslav Kostic – HONI
- Mansour Jalali – Kinectrics
- Lixi Zhang – Kinectrics
- Dave Marttila – Kinectrics
- Andre Maurice – Kinectrics
- Garreth Coelho – Kinectrics

11 References

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Appendix A Acronyms and Abbreviations

AF	Acceleration factor
ALT	Accelerated life test
CPLD	Complex programmable logic device
E_a	Activation energy
EOL	End-of-life
EEPROM	Electrically-erasable programmable read-only memory
ESL	Expected service life
HONI	Hydro One Networks Inc.
IC	Integrated circuit
k	Boltzmann’s constant
K	Kelvin
LCD	Liquid crystal display
LED	Light-emitting diode
MTTF	Mean-time-to-failure
SEM	Scanning electron microscopy
TTF	Time-to-failure
T_S	Stress temperature
T_U	Normal-use temperature

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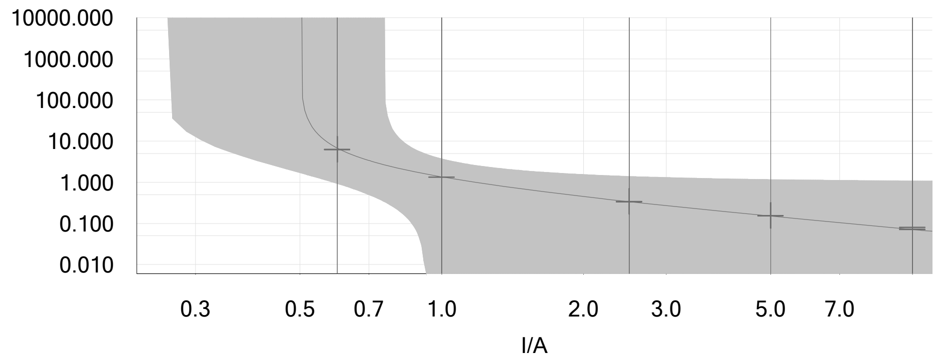
Appendix B Extract from Omicron Test Set for MCGG 22

Shot Test Results:

Type	Relative To	Factor	Magnitude	Angle	tnom	tact	Deviation	Overload	Result
L1-L2	I #1 Phase	1.200	600.0 m A	n/a	6.750 s	6.229 s	-7.726 %	No	Passed
L1-L2	I #1 Phase	1.200	600.0 m A	n/a	6.750 s	6.221 s	-7.837 %	No	Passed
L1-L2	I #1 Phase	1.200	600.0 m A	n/a	6.750 s	6.245 s	-7.476 %	No	Passed
L1-L2	I #1 Phase	2.000	1.000 A	n/a	1.350 s	1.338 s	-881.5 m %	No	Passed
L1-L2	I #1 Phase	2.000	1.000 A	n/a	1.350 s	1.338 s	-911.1 m %	No	Passed
L1-L2	I #1 Phase	2.000	1.000 A	n/a	1.350 s	1.338 s	-888.9 m %	No	Passed
L1-L2	I #1 Phase	5.000	2.500 A	n/a	337.5 ms	337.9 ms	118.5 m %	No	Passed
L1-L2	I #1 Phase	5.000	2.500 A	n/a	337.5 ms	337.3 ms	-59.26 m %	No	Passed
L1-L2	I #1 Phase	5.000	2.500 A	n/a	337.5 ms	338.2 ms	207.4 m %	No	Passed
L1-L2	I #1 Phase	10.00	5.000 A	n/a	150.0 ms	153.7 ms	2.467 %	No	Passed
L1-L2	I #1 Phase	10.00	5.000 A	n/a	150.0 ms	154.5 ms	3.000 %	No	Passed
L1-L2	I #1 Phase	10.00	5.000 A	n/a	150.0 ms	154.5 ms	3.000 %	No	Passed
L1-L2	I #1 Phase	20.00	10.00 A	n/a	71.05 ms	71.50 ms	629.6 m %	No	Passed
L1-L2	I #1 Phase	20.00	10.00 A	n/a	71.05 ms	79.40 ms	11.75 %	No	Passed
L1-L2	I #1 Phase	20.00	10.00 A	n/a	71.05 ms	70.70 ms	-496.3 m %	No	Passed

Charts for Fault Types:

Type	Angle
L1-L2	n/a



State:

15 out of 15 points tested.
15 points passed.
0 points failed.

General Assessment: Test passed!

Appendix C Extract from Omicron Test Set for D60

Report Status: Passed

Testmodules Embedded: 4
Testmodules Passed: 4
Testmodules Failed: 0

Test Object - Device Settings

Substation/Bay:

Substation:	Substation	Substation address:	Substation address
Bay:	bay	Bay address:	bay address

Device:

Name/description:	Multilin D60	Manufacturer:	GE
Device type:	Line Distance Protection	Device address:	device address
Serial/model number:	serial no.		
Additional info 1:	Protected object name		
Additional info 2:	L90-UG9-ALH-F8L-H6C-L8L-N6C-S6C-U4D-W7K		

Nominal Values:

f nom:	60.00 Hz	Number of phases:	3
V nom (secondary):	115.0 V	V primary:	115.0 V
I nom (secondary):	5.000 A	I primary:	1.600 kA

Residual Voltage/Current Factors:

VLN / VN:	1.732	IN / I nom:	1.000

Limits:

V max:	500.0 V	I max:	50.00 A

Debounce/Deglitch Filters:

Debounce time:	3.000 ms	Deglitch time:	0.000 s

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1.5 (5.2.3) PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

Hydro One is committed to achieving the productivity and cost efficiency goals outlined in its Business Plan, a copy of which is provided in Exhibit A, Tab 3, Schedule 1, Attachment 1. To give effect to this commitment, Hydro One has aligned its planning, execution and reporting functions around performance outcomes that are consistent with the Ontario Energy Board's ("OEB") Renewed Regulatory Framework ("RRF") outcomes. The RRF outcomes relate to Customer Focus, Operational Effectiveness, Policy Responsiveness and Financial Performance. Hydro One's performance outcomes are reflected in its Transmission Scorecard (see Figure 1), which assists Hydro One in transparently monitoring and measuring performance relative to these outcomes. The evolution of Hydro One's Transmission Scorecard is discussed below in Transmission System Plan ("TSP") Section 1.5.2.

Hydro One maintains and tracks measures across its business to align work execution in each line of business with the corporate strategic objectives, as discussed in TSP Section 2.1.2. The performance outcomes set out in the evolved Transmission Scorecard are aligned with the OEB's RRF outcomes. Hydro One's overall performance against these targets is reported to stakeholders by means of regulatory scorecards for each of the transmission and distribution businesses, as well as through Hydro One's Team Scorecard and Operational Scorecard. The incentives that are embedded in Hydro One's compensation plans support continuous improvement in Hydro One's performance measures and are designed to both increase efficiency and deliver outcomes that customers value. In addition, Hydro One has established a process to evaluate its corporate targets on an annual basis. This process aligns with the development and approval of the Business Plan.

In the sections that follow, Hydro One describes its performance measurement process, including governance, the methodologies used for each of the measures and the manner in which Hydro One has responded to specific concerns raised by the OEB in Hydro One's last transmission rate proceeding. In addition, this section provides an update on Hydro One's performance since its last transmission rate proceeding.

1.5.1 (5.2.3 A) PERFORMANCE MEASUREMENT STRUCTURE, PROCESS, AND GOVERNANCE

Hydro One is taking steps to increase the emphasis it places on performance measurement and planning. Hydro One has increased transparency in all aspects of its budgeting and performance measurement processes to ensure that cross-functional stakeholders, such as various lines of business, its Finance and Regulatory Affairs groups, the Executive Leadership Team ("ELT") and Operations Managers, are equipped with accurate and consistent information to drive business decisions and achieve performance targets.

The evolved Transmission Scorecard (see Figure 1) details Hydro One's historical performance in each area and establishes performance outcomes that Hydro One has targeted to achieve over the 2020 to 2024 plan period and the 2020 to 2022 rate period in respect of each performance measure. Hydro One is committed to achieving the performance outcomes for each measure through the execution of its 2019 to 2024 investment plan. As noted in TSP Section 2.1.2, the investment plan has been optimized to drive performance towards these outcomes, ensuring regulatory compliance, and balancing the customers' needs and preferences, the transmission asset and system needs, and rate impacts.

The evolved Transmission Scorecard is made up of performance measures that enable Hydro One to monitor, track and demonstrate performance relative to outcomes that are valued by its transmission customers.

There are a number of internal stakeholders that are directly engaged in and have responsibility for overseeing or implementing Hydro One's performance measurement and monitoring process.

Details of this process are set out in Hydro One's Performance Reporting Governance Framework, a copy of which is provided in TSP Section 1.5, Attachment 1.

1.5.2 (5.2.3 A, B, C) PERFORMANCE MEASUREMENT METHODS AND MEASURES

In its Decision and Order on Hydro One's 2017-2018 transmission rate application (the "Decision"),[1] the OEB directed Hydro One to develop and file an evolved scorecard reflecting the OEB's feedback. As discussed below, the evolved Transmission Scorecard provides continuity with Hydro One's previously filed Transmission Scorecard while also reflecting the OEB's direction. Additionally, the measures reflected in the evolved Transmission Scorecard have been influenced by internal and external sources that include Hydro One's past performance management measures, benchmarking studies, and scorecards and measures of other utilities in the public domain. The measures were also informed by the OEB's guidance in the Handbook for Utility Rate Applications[2] ("Handbook") by reflecting the following key considerations and OEB filing requirements[3]:

- A focus on strategy and results, not activities;
- The need to demonstrate continuous improvement;
- Outcomes that are demonstrated to be of value to customers; and
- Performance measures that accurately measure whether outcomes are being achieved, and that include stretch goals to demonstrate enhanced effectiveness and continuous improvement.

Hydro One has updated the targets in its evolved Transmission Scorecard to reflect continuous improvement and successful execution of the programs and projects in its Business Plan. The

[1] Decision and Order, EB-2016-0160, September 28, 2017, s. 5.0
[2] Ontario Energy Board, Handbook for Utility Rate Applications, October 13, 2016, p.16
[3] Refer to TSP Section 1.5, Attachment 2 for the unit cost metrics mandated under the OEB's Filing Requirements for Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications, Chapter 5, July 12, 2018, p.11, s.5.2.3 b)

discussion below first provides an overview of the performance measures that are reflected in Hydro One's evolved Transmission Scorecard. This is followed by a discussion of the manner in which Hydro One has considered and responded to the concerns raised by the OEB and the directions given in the Decision.

Performance Outcomes	Performance Categories	Measures		2014	2015	2016	2017	2018	Targets 2019	2020	2021	2022	2023	2024
Customer Focus	Customer Satisfaction	Satisfaction with Outage Planning Procedures (% Satisfied)		86	92	89	94	85	86	86	87	87	88	88
		Overall Customer Satisfaction (% Satisfied)		77	85	78	88	90	88	88	88	88	88	88
	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs		11.8	14.3	9.7	9.5	10.1	12.0	11.7	11.5	11.3	11.0	10.8
Operational Effectiveness	Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)		1.8	1.7	1.1	1.2	1.1	1.1	1.1	1.0	0.9	0.9	0.9
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)		0.60	0.59	0.46	0.65	0.83	0.55	0.54	0.53	0.52	0.51	0.50
		T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)		0.48	0.50	0.33	0.47	0.50	0.49	0.48	0.48	0.47	0.46	0.45
		T-SAIDI (Ave minutes of interruptions per Deliver Point)		36.7	43.9	80.8	42.8	70.0	35.4	34.66	33.96	33.28	32.62	31.97
		System Unavailability (%)		0.48	0.63	0.70	0.69	0.71	0.48	0.47	0.47	0.46	0.45	0.44
		Unsupplied energy (minutes)		12.2	11.8	11.4	13.2	19.5	9.8	9.59	9.40	9.21	9.02	8.84
	Asset & Project Management	Transmission System Plan Implementation Progress (%)		99	105	100	94	99	100	100	100	100	100	100
		CapEx as % of Budget		90	106	105	100	98	100	100	100	100	100	100
		OM&A Program Accomplishment (composite index)			97	99	108	108	100	100.0	100.0	100.0	100.0	100.0
		Capital Program Accomplishment (composite index)			122	59	88	116	100	100.0	100.0	100.0	100.0	100.0
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)		8.4	9.0	8.6	7.9	7.7	7.3	7.8	7.9	7.7	7.3	7.0
		OM&A per Gross Fixed Asset Value (%)		2.7	2.9	2.5	2.3	2.3	1.8	1.8	1.7	1.6	1.5	1.5
		Line Clearing Cost per kilometer ($/km)		2,495	2,234	1,966	2,100	2,797	2,295	2,264	2,200	2,175	2,100	2,100
		Brush Control Cost per Hectare ($/Ha)		1,624	1,566	1,542	1,356	1,539	1,625	1,620	1,630	1,608	1,608	1,608
Public Policy Responsiveness	Connection of Renewable Generation	% on-time completion of renewables customer impact assessments		100	100	100	100	100	100	100	100	100	100	100
	Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning progress - Deliverables met, %		100	100	100	100	100	100	100	100	100	100	100
		End-of-Life Right-Sizing Assessment Expectation					Met	Met	Met	Met	Met	Met	Met	Met
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.69	0.13	0.20	0.13	0.12						
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.16	1.39	1.43	1.47	1.53						
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.36	9.30	9.19	8.78	9.00						
			Achieved	13.12	10.93	10.02	9.03	11.08						

Figure 1 – Evolved Electricity Transmitter Scorecard & Targets – Hydro One Networks Inc.[4]

[4] Satisfaction with Outage Planning Procedures survey was not performed in 2013.The return on equity achieved values for 2013 to 2015 were restated.

Overview of Hydro One's Transmission Performance Measures

Customer Focus

The measures in Table 1 were selected to demonstrate that services are provided to meet customers' expected level of service and align with the OEB's Decision.

Table 1 - Customer Focus Measures

Performance Category	Measures	Description
Service Quality	Satisfaction with Outage Planning Procedures (% Satisfied)	The Ontario Grid Control Centre ("OGCC") Customer satisfaction survey relates Customer Satisfaction with relevant business processes and transactional customer experience. The question asked is: How would you rate Hydro One's OGCC procedures on outage planning?
	Customer Delivery Point Performance, Standard outliers as % of Total Delivery Points	The percentage of customer Delivery Points ("DPs") deemed as either group or individual outliers.
Customer Satisfaction	Overall Customer Satisfaction, corporate survey (% Satisfied)	This measure reflects the overall satisfaction levels of three major transmission customer segments (Transmission End Users, Local Distribution Companies ("LDC") and Transmission-Connected Customer Generators). The survey measures customers' overall opinion of Hydro One (whether they have interacted with Hydro One recently or not). Hydro One seeks to uncover perceptions of how well it is meeting customer expectations and delivering on critical success factors. The survey is conducted online followed by computer-assisted telephone interviewing if customer prefers/is not reached.

Operational Effectiveness

The measures in Table 2 were selected to demonstrate Hydro One's commitment to continuous improvement in performance and execution. The measures also show how Hydro One delivers on system reliability and service quality objectives.

Table 2 - Operational Effectiveness Measures[5]

Performance Category	Measure	Description
Safety	Recordable Rate (#Recordable Injuries/Illnesses per 200,000 hours worked)	Work-related injuries/illnesses to that result in: restricted work, lost time, loss of consciousness, medical attention beyond first aid, death, or any other significant work-related injury or illness diagnosed by a physician or other health care professional and are confirmed by a Hydro One Occupational Health Nurse. The measure applies to Hydro One Networks Inc. employees only (not contractors).
System Reliability	T-SAIFI-S (Sustained Interruption Frequency) (Average # of times that power to a Customer is interrupted per Delivery Point)	Average Frequency of Delivery Point Sustained Interruptions is an indicator of the average number of unplanned interruptions that customers experience and is presented as number of interruptions per delivery point per year. Only includes sustained (1 minute and longer) interruptions.
	T-SAIFI-M (Momentary Interruption Frequency) (Average # of times that power to a Customer is interrupted per Delivery Point)	Average Frequency of Delivery Point Momentary Interruptions is an indicator of the average number of unplanned interruptions that customers experienced and is presented as number of interruptions per delivery point per year. Only includes momentary (less than 1 minute) interruptions.
	T-SAIDI (Duration) (Average # minutes that power to a Customer is interrupted per Delivery Point)	Average Duration of Delivery Point Interruptions is an indicator of the average minutes of unplanned interruptions that customers experienced and presented as interruption minutes per delivery point per year. Only sustained (1 minute and longer as per the Canadian Electricity Association ("CEA") industry standard) interruptions contribute to this measure.

[5] For OEB reporting and filing, capital expenditures have been remapped to the OEB categories of System Access, System Renewal, System Service, and General Plant. Internally, Hydro One uses Sustainment, Development, Operations, and Common Corporate Costs & Other Costs ("SDOC") as categories for both OM&A and capital. For internal processes, including the supporting data as well as generating and reporting on scorecards, Hydro One utilizes the SDOC categories. To maintain alignment with the existing internal processes and to provide continuity with the previous application (EB-2016-0160), the metrics have not been renamed to the OEB categories.

Performance Category	Measure	Description
	System Unavailability (% of time system equipment is unavailable)	Transmission System Unavailability captures the total duration transmission equipment is out of service due to unplanned outages.
	Unsupplied Energy (minutes)	Unsupplied Energy is an indicator of total energy not supplied to customers due to delivery point unplanned interruptions. In order to make it comparable among different sizes of utilities, the unsupplied energy is normalized by the system peak. The unit of the measure of normalized unsupplied energy is expressed in “system minutes”.
Asset & Project Management	Transmission System Plan Implementation Progress	The Transmission System Plan Implementation Progress measure compares the total actual in-year sustainment, development, and operating expenditures for in-service additions to the total internal company scorecard budget expenditures for in-service additions, including any OEB carry-forward variance.
	Capital Expenditures as % of Budget	Progress is measured as the ratio of actual total capital expenditures to the total amount of planned capital expenditures.
	Operations, Maintenance, & Administration (“OM&A”) Program Accomplishment (composite index)	The Transmission (“Tx”) OM&A Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx OM&A Programs against the weighted budget. There are eight programs monitored for this measure including: 1) Forestry Line Clearing; 2) Brush Control; 3) PCB Testing and Retro fill; and Station Preventive Maintenance programs which include 4) Power Equipment, 5) Ancillary Equipment, 6) Protection and Control, 7) Telecom, 8)Infrastructure.
	Capital Program Accomplishment (composite index)	The Tx Capital Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx Capital Programs against the weighted budget. The six programs monitored for this measure include the Steel Structure Coating Program, Tx Lines Insulator Replacement Program, Tx Wood Pole Replacement, Tower Foundation Refurbishment, Shieldwire Replacement and Purchase of Station Spare Transformers.
Cost Control	Total OM&A and Capital per Gross Book Value of In-Service Assets	Demonstrates Transmission cost effectiveness by comparing the ratio of Total Capital and OM&A to Gross Book Value of Fixed Asset costs.

Performance Category	Measure	Description
	OM&A/Gross Fixed Asset Value (%)	Demonstrates Transmission cost effectiveness by comparing the ratio of OM&A to Gross Book Value of Fixed Asset costs.
	Line Clearing Cost per kilometer ($/km)	Cost associated with line clearing activities, per kilometer completed for the year.
	Brush Control Cost per Hectare ($/Ha)	Cost associated with brush control, per hectare completed for the year.

Public Policy Responsiveness

The measures in Table 3 were selected to demonstrate Hydro One's commitment to deliver on the obligations mandated by the government and regulatory agencies.

Table 3 - Public Policy Responsiveness Measures

Performance Category	Measure	Description
Renewable Energy	% on-time completion of renewables customer impact assessments	For Transmission-connected generators, Hydro One is obligated under the Transmission System Code to complete a customer impact assessment (CIA) for renewables in 150 days.
Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right Sizing	Regional Infrastructure Planning Progress: % Deliverables Met	Measures progress in meeting the deliverables including meeting the Transmission System Code prescribed timelines and delivering the required products. The number of deliverables will vary in a given year. Deliverables include plans, reports and LDC status update letters.
	End-of-Life Right-Sizing Assessment Expectation	This qualitative measure gauges Hydro One's performance in meeting the expectation that no more than two (2) assessment opportunities for right-sizing end-of-life equipment are missed during the year, for all regions assessed in the year as part of the Regional Planning Process. The number of regions assessed may vary in each year.

Financial Performance

The measures in Table 4 were selected to provide financial visibility and to demonstrate that the continuous improvements in execution and cost performance highlighted in 'Operational Effectiveness' are sustainable. The measures used for the Electricity

Transmission Scorecard align with the Financial Ratio measures used in the Electricity Distributor Scorecard.

Table 4 - Financial Performance Measures

Performance Category	Measures	Description
Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	Hydro One measures the ratio of current assets to current liabilities. Current assets are defined as cash or other assets to be converted to cash within the year and that can be used to fund daily operations and pay ongoing expenses. Current liabilities are defined as short term debts or financial obligations that become due within the year.
	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	The debt-to-equity ratio is a measure of Hydro One's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60 per cent to 40 per cent debt-to-equity structure (a ratio of 1.5).
	Profitability: Regulatory Return on Equity -Deemed Return on Equity (included in rates)	Measures the OEB-approved Return on Equity that is embedded in the transmitter's base rates. Return on Equity is the rate of return that the utility is allowed to earn through its transmission rates, as approved by the OEB.
	Profitability: Regulatory Return on Equity -Achieved Regulated Return on Equity	Measures the transmitter's achieved Regulated Return on Equity earned in the preceding fiscal year. The reported return is calculated on the same basis that was used in establishing the transmitter's base rates. This shows the utility's actual Return on Equity earned each year.

Response to OEB Directions from EB-2016-0160

Customer Satisfaction

In the Decision, the OEB directed Hydro One to develop performance indicators that better reflect the satisfaction level of the ultimate end-use customer. The OEB also indicated that it does not consider the satisfaction level of a directly connected LDC to be indicative of the LDC customers' level of satisfaction, and that LDCs do not necessarily represent the interests of their customers on transmission issues nor do they suffer the same negative consequences if transmission performance levels are poor.

Hydro One measures overall transmission customer satisfaction using a corporate survey. The measure used to indicate customer satisfaction reflects the overall satisfaction levels of three major transmission customer segments:

- Transmission End-Users;
- LDCs; and
- Transmission-connected Customer Generators.

The survey measures these customers' overall opinion of Hydro One (whether they have interacted with Hydro One recently or not). It seeks to uncover perceptions of how well Hydro One is meeting customer expectations and delivering on critical success factors. Additionally, Hydro One uses a service quality measure to measure satisfaction with the outage planning procedures of the Ontario Grid Control Centre ("OGCC"). The OGCC customer satisfaction survey relates customer satisfaction to relevant business processes and transactional customer experience. This additional component provides Hydro One with direct insight into how outage planning procedures impact supply to each of the three transmission customer groups. Proper outage notifications provide transmission customers with sufficient advanced notice to allow planning, notifications, and restoration of service to Hydro One's transmission customers and, ultimately, any of their end-use customers. These are described further in TSP Section 1.3.

LDC End-User Satisfaction

Hydro One's transmission system is the upstream supplier of electricity to LDCs across the Province of Ontario. Electricity is transmitted over the Hydro One transmission system to Delivery Points ("DPs") with the LDCs. DPs are boundaries between the electricity systems of Hydro One and the LDCs. Each LDC has significant power requirements, unique needs, a diverse group of end-use customers, and most importantly, distribution systems designed to meet their requirements and needs, to service their end-use customers. There is no direct link between the Hydro One transmission system and the LDC's end-use customers.

In Hydro One's 2017 Transmission Customer Engagement Survey, Hydro One asked LDCs to identify whether or not their responses to the survey were informed by their own customer engagement activities for the purposes of their own rate applications, or by any other customer research. Of the 28 respondents, 11 answered "yes" to this question. Additionally, Hydro One's Account Executives interact with the LDCs, and engage the LDCs in discussion regarding the needs of their ultimate end-use customers.

For an LDC's end-use customers to be able to express their level of satisfaction with the upstream electricity supply provided by Hydro One, ultimate end-use customers would need to have the means or the mechanisms in place to create a positive correlation between their satisfaction and Hydro One's transmission system, while also excluding factors and variables relating to their LDC's distribution system. Similarly, for Hydro One to gauge the satisfaction of an LDC's end-use customers, it would need to be able to establish a connection beyond the DP with the LDC to create a link to the LDC's end-use customers. Furthermore, to align with the guidance in the Handbook, Hydro One would need to demonstrate continuous improvement in the satisfaction levels of the LDC's ultimate end-use customers. This would require Hydro One to not only manage its transmission system, but also to be able to exercise control and influence on the distribution systems of the LDCs that it serves, and in some cases on the distribution systems of LDCs that are embedded within those systems.

Section 2.1.4.2 in the OEB's Reporting and Record-keeping Requirements ("RRR") Filing Guide for Electricity Distributors outlines the requirements for reporting on system reliability[6]. Distributors are required to report system reliability exclusive of the impact of loss of supply, which is defined as an interruption due to problems associated with assets owned and/or operated by another party, i.e., upstream, and/or the bulk electricity

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[6] RRR Filing Guide for Electricity Distributors' Reporting and Record Keeping Requirements (RRR), Ontario Energy Board, March 2017

supply system. In a letter[7] dated March 13, 2017, the OEB updated its RRR filing guidelines requiring distributors to also exclude the impact of Major Events when reporting on system reliability. The reasoning provided in the background section of the letter was that by adjusting for the impact of not only loss of supply, but also of Major Events, the reliability measures would be more indicative of a distributor's ability to manage interruptions caused by circumstances that are directly within the distributor's control. The principles outlined in the RRR filing guidelines recognize the limitations on the control and influence of the transmitter. The general principle demonstrated by the OEB's approach in the RRR filing guidelines is that customer satisfaction measures should gauge satisfaction in areas which can be controlled and influenced to achieve the intent of the key considerations in the Handbook.

Applying this principle to Hydro One's transmission system, there may be limited utility in Hydro One reporting on measures relating to customer satisfaction levels for customers served by distribution systems over which Hydro One exercises no influence or control. To correlate the service satisfaction levels of ultimate end-use customers of LDCs to the service performance of an upstream transmitter would require a means for LDC end-use customers to clearly distinguish between the impacts of transmitter performance and the impacts of distributor performance on the service they ultimately receive. Hydro One has not been able to implement such a measure.

Transmission System Plan Execution

In its Decision, the OEB expressed concern with Hydro One's asset management measures for "*In-Service Capital Additions as % of OEB-Approved Plan*" and "*CapEx as % of Budget*". The OEB indicated that these measures could potentially run counter to the cost control performance indicators. Notably, the OEB distinguished between the use of

[7] Reporting of Customer Interruptions Data Related to Major Events, Ontario Energy Board, March 13, 2017

the OEB-Approved Plan factor in one of the measures and its role in approving capital envelopes which provides an input to the revenue requirement and ultimately approved rates, rather than approved capital plans. The concern expressed was that the proposed asset management measures did not allow for the eventuality that execution of particular elements of the original plan could run counter to the objective of serving the best interests of Hydro One's customers. To address the OEB's concerns, Hydro One is proposing a measure, comparable to the "*Distribution System Plan Implementation Progress*" measure currently reported on Hydro One's Electricity Distributor Scorecard. The proposed measure, "*Transmission System Plan ("TSP") Implementation Progress*", tracks actual in-service additions compared to the budget, including any OEB variances.

The measure compares the total actual sustainment, development and operating expenditures for in-service additions to the total internal company scorecard budget expenditures for in-service additions, including any carry-forward variances. Hydro One is of the view that the proposed measure appropriately addresses the OEB's concerns identified above.

Asset management is at the core of Hydro One's business planning function. Hydro One has considered implementing broader Asset Management measures that are directly related to positive outcomes for its customers. For instance, performance measures related to improvements in Hydro One's asset diagnostics that enhance the accuracy of asset replacement schedules could result in direct benefits to customers. To facilitate this process, Hydro One commissioned certain studies from third party experts to validate Hydro One's approach to managing specific types of transmission assets. These studies are discussed in TSP Section 1.4. Hydro One will review and consider the key findings and recommendations of these studies for possible implementation. The development of asset-specific measures will be considered during the review.

Plan Expenditures

In the Decision, the OEB also determined that plan execution is important but should not be driven by a performance indicator solely based on ensuring the level of spending originally considered reasonable is spent. Hydro One is introducing the additional measures shown in Table 5, which are directly related to expenditures. These are expected to drive Hydro One toward having a more positive and direct impact on customer outcomes.

Table 5 - Transmission Scorecard, Asset & Project Management and Cost Control Measures

Performance Category	Measure	2014	2015	2016	2017	2018
Asset & Project Management	OM&A Program Accomplishment (composite index)	N/A	96.6	99.2	107.7	108.0
	Capital Accomplishment (composite index)	N/A	122.2	59.4	87.8	116.0

Revenue Requirement Reductions through Productivity Improvements

In the Decision, the Board directed Hydro One to establish firm short and long-term targets for productivity improvements and associated reduction in revenue requirements as a means to drive continuous improvement and improve Hydro One's internal and external benchmarking standings. A discussion of these targets can be found in TSP Section 1.6.

Public Policy Responsiveness

In the Decision, the Board did not consider the inclusion of North American Electric Reliability Corporation ("NERC") or Northeast Power Coordinating Council ("NPCC") standards to be aligned with the intent of the scorecard objectives. Hydro One has removed these measures from the evolved Transmission Scorecard.

Unit-Cost Measures of Productivity, Safety, Reliability, and Quality of Service Improvements

The OEB directed Hydro One to put more emphasis on performance measures in the scorecard so as to provide objective year-over-year unit cost measures of productivity, safety, reliability, and quality of service improvements.

Hydro One continues to focus on opportunities to become more efficient in the deployment of capital and in managing costs. The measures shown in Table 6 will be used to monitor this ability, emphasizing execution and cost performance and reflecting the outcomes of the overall business performance.

In 2018, Hydro One's transmission line clearing and brush control activities accounted for approximately 78 per cent of the overall transmission Forestry budget. The unit cost measures are calculated by dividing the annual expenditure on a given program by the number of units completed in that year. These measures are presented at a program level and have not been normalized, which may lead to some variations in the annual unit costs due to the mix of work undertaken throughout the year. For example, brush control unit costs can be affected by vegetation density. The Forestry team incorporates integrated vegetation management principles while maintaining transmission corridors on vegetation clearing cycles of 4, 6 or 8 years. Cycle lengths have been set to ensure that Right-Of-Ways ("ROW") are in good condition and maintain a sustainable level of reliability between maintenance cycles.

Table 6 - Unit-Cost Measures

Performance Category	Measure	2014	2015	2016	2017	2018
	Line Clearing Cost per kilometer Completed ($/km)	2,495	2,234	1,966	2,100	2,797
	Brush Control Cost per Hectare Completed ($/Ha)	1,624	1,566	1,542	1,356	1,539

Qualitative Measures of Public Policy Responsiveness

The OEB proposed that Hydro One should consider expanding its Public Policy Responsiveness measures to include a qualitative assessment of Hydro One's response performance related to the policy objectives embedded in the government's Smart Grid initiatives as one example of the type of measure the OEB anticipates under this element of the evolved Transmission Scorecard.

For 2017 reporting and onwards, Hydro One has introduced a measure designed to provide a qualitative assessment of the Hydro One's alignment with the policies set out in the 2017 Long-Term Energy Plan (the "LTEP").[8] Section 4 of the LTEP, "*Improving Value and Performance for Consumers*", describes the province's policies regarding the need for achieving continuous efficiencies and maintaining a culture of innovation in the energy sector. One component of achieving efficiencies is the right-sizing of end-of-life equipment. As described in the LTEP, equipment which is reaching end-of-life presents a unique opportunity to reassess needs and requirements, and to ensure that replacement equipment and facilities are right-sized to reflect present or anticipated needs and requirements. The assessment may identify opportunities to downgrade or eliminate equipment or facilities in scenarios where demand is expected to decrease; replace with similar equipment with the same or higher ratings where demand is expected to increase; and provide an opportunity to consider greater system resiliency and advanced technological solutions in areas of increased demand. The assessments are performed with the objective of achieving continuous efficiencies and improvements in the value and performance for customers.

The proposed "*End-of-Life Right-Sizing Assessment Expectation*" measure is intended to track the qualitative performance of Hydro One in making right-sizing decisions for all identified end-of-life equipment or facilities. Hydro One will assess its performance by

[8] Ontario's Long-Term Energy Plan 2017, Delivering Fairness and Choice, Government of Ontario

setting a target of a maximum of two (2) missed equipment right-sizing opportunities in annual regional planning assessments. The qualitative performance assessment is either “Met” or “Not Met” based on the quantitative maximum of two.

The proposed new measures are included in the evolved Transmission Scorecard in Figure 1.

Outcomes of Hydro One’s Overall Business

The OEB proposed that Hydro One should consider the merits of implementing measures that reflect outcomes of Hydro One’s overall business, such as gross fixed assets per unit of load service capacity, to more fully illustrate its overall cost of service provision. In addressing the gross fixed assets per unit of load serving capacity measure specifically, Hydro One has reviewed this recommendation and does not consider it to be an appropriate measure against which to assess outcomes or against which it can demonstrate continuous improvement.

Gross fixed assets include the price of assets, which generally experience upward trends due to various factors, including inflation, whereas the unit of load serving capacity is a physical measure of kW or kWh. Therefore, the ratio would have a natural tendency to increase over time, due to the effects on the numerator, even if the unit of load serving capacity remained constant. Additionally, the generation mix is likely to contain more distributed generation than large scale generation. The gross fixed assets would grow at a faster rate due to having an increased distributed generation mix over time, which would be driven by an increased demand for additional transmission lines, towers, and transformers to connect the distributed generators to the transmission system. These distributed generation connections do not benefit from the same economies of scale as connecting large scale generation. Such a measure would not be appropriate and would likely not allow for opportunities to demonstrate continuous improvement and to align with the key principles of the RRF.

Continued Development of Hydro One's Performance Management System

The OEB directed Hydro One to continue to develop its performance management system and scorecard to reflect the OEB's observations and determinations. Hydro One believes that the evolved Transmission Scorecard and the associated, updated Performance Reporting Governance Framework (TSP Section 1.5, Attachment 1) demonstrate Hydro One's commitment to continue to develop its performance management system and scorecard to reflect the OEB's observations and determinations. In doing so, Hydro One has considered the merits of implementing measures that reflect the overall business and which are expected to positively impact outcomes.

1.5.3 (5.2.3 C, D) PERFORMANCE MEASUREMENT OUTPUTS AND PERFORMANCE UPDATE

The following sections provide updates on Hydro One's performance trends since its last transmission rate proceeding, organized by the corresponding performance outcomes (i.e. Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance). As shown in Figure 1, Hydro One has provided results for 2018 and aligned the discussions in the section below to reflect those results.

Customer Focus

Customer Satisfaction: Satisfaction with Outage Planning Procedures (per cent satisfied)

Hydro One measures satisfaction with the outage planning procedures of its OGCC using a transactional survey which asks respondents to rate Hydro One's OGCC procedure on outage planning on a five-point scale. The OGCC continues to improve across several spectrums, including: customer assistance, service delivery, and outage planning procedures among its customer base.

Although, satisfaction with outage planning procedures decreased by 9 percentage points in 2018 compared to 2017, historical results are not comparable to the 2018 value. In

2018, Hydro One made changes to the survey methodology in an attempt to prompt more accurate responses from survey participants. Additionally, the survey was also published online in order to allow for greater flexibility for customers and to also provide an additional level of comfort with answering the questions online versus speaking to a representative of Hydro One. Lastly, the survey questions were also standardized across all customer types to allow for better comparison of response themes.

For these reasons, a comparison to historical results is not appropriate. Targets were set based on the new survey methodology, and over the plan period, Hydro One is targeting 88 per cent satisfaction with outage planning procedures.

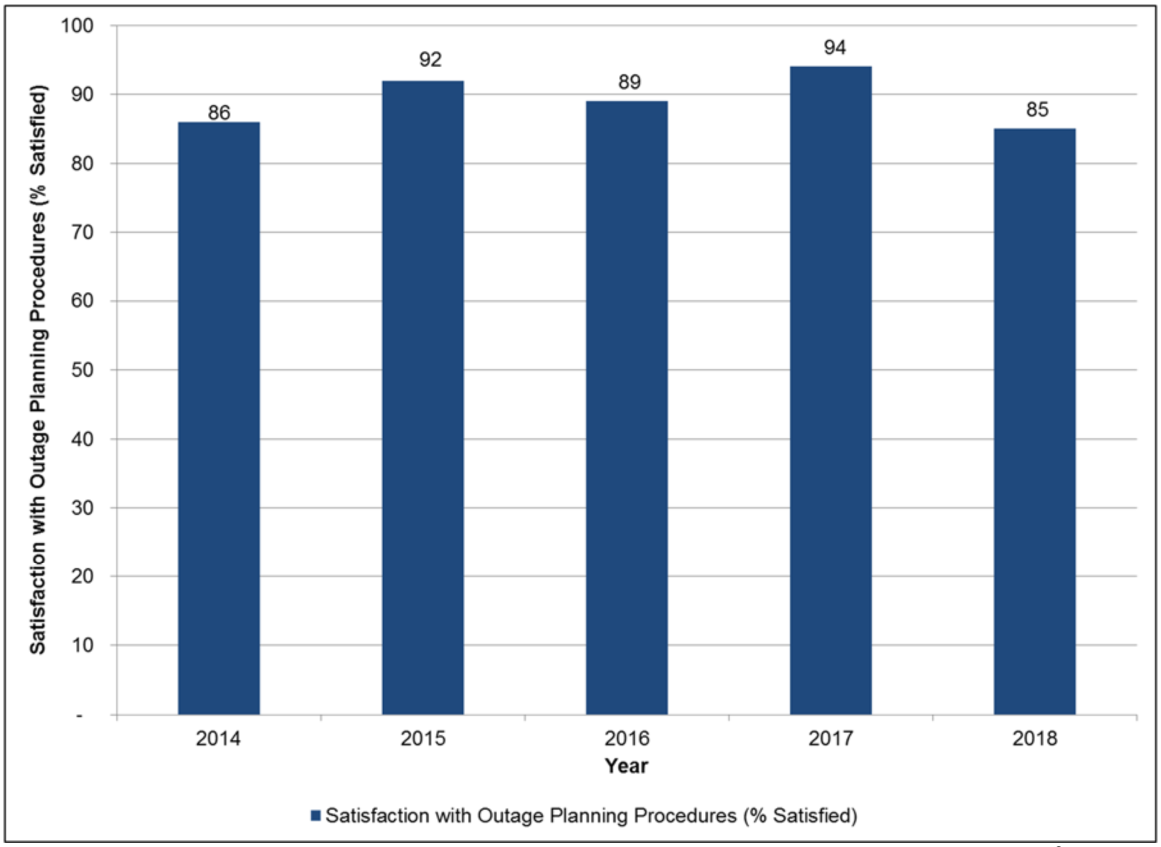

Figure 2 - Satisfaction with Outage Planning Procedures (% Satisfied)[9]

<u>*Customer Satisfaction: Overall Customer Satisfaction in Corporate Survey (% satisfied)*</u>

Hydro One conducts an annual customer satisfaction survey online, followed by computer-assisted telephone interviews based on customer preference or availability. Hydro One measures overall customer satisfaction by surveying the overall satisfaction level of its three major transmission customer segments: 1) Transmission End Users; 2) LDCs; and 3) Transmission-connected Customer Generators. The survey also measures key drivers of satisfaction among large Transmission customers by monitoring Hydro One's performance in four key service areas: 1) Price; 2) Customer Service; 3) Product Quality and Reliability; and 4) Relationship. The survey measures the opinions of

[9] Average and trend lines are not shown in Figure 2 since the survey methodology changed in 2018.

customers and seeks to uncover perceptions of how well Hydro One is meeting their expectations. Customer satisfaction levels in the areas of Customer Service, Product Quality and Reliability and Relationship have been relatively stable in recent years. However, the Price measure is at the lowest level since tracking this measure began.

In 2018, overall customer satisfaction increased to the highest point in the past six years at 90 per cent, which represents a 2 percentage point increase compared to 2017. The increase in overall satisfaction can be largely attributed to LDCs and End-User customers. Both showed continuity of improvement that started previous year, with satisfaction ratings climbing to their highest points since tracking began. Generator customers continued to show consistent satisfaction with Hydro One, with satisfaction ratings rising steadily over the past few survey waves. Both scorecard metrics show improvement over the previous year. LDC customer ratings of Hydro One are at their highest over time, with a significant increase in satisfaction with Hydro One keeping commitments and making decisions promptly. Consistent with 2017, Generators continued to identify product and planning issues (outage planning, infrastructure upgrades) as key areas for Hydro One to address in order to increase satisfaction

Hydro One is committed to improving satisfaction levels for these customer segments. Considerable focus will be placed on a renewed commitment to customer advocacy and becoming a company that is easy to do business with. This includes a review of Hydro One's processes and practices to ensure Hydro One keeps commitments and is responsive to the needs of these customers. Improving customer service for our large customers will be driven by ensuring Hydro One is easy to do business with.

Insights from the 2017 surveys reveal the following areas where customers are seeking improvements:

- providing more assistance with investigating power quality events;
- reducing timelines for connection estimates;

- reducing connection costs;
- improving communications and transparency; and
- becoming easier to do business with.

Hydro One's average performance over the past five years (2014-18) was 84 per cent and the overall customer satisfaction trend is improving (see Figure 3).

Over the plan period, Hydro One aims to improve against its five-year average, and is targeting 90 per cent overall customer satisfaction.

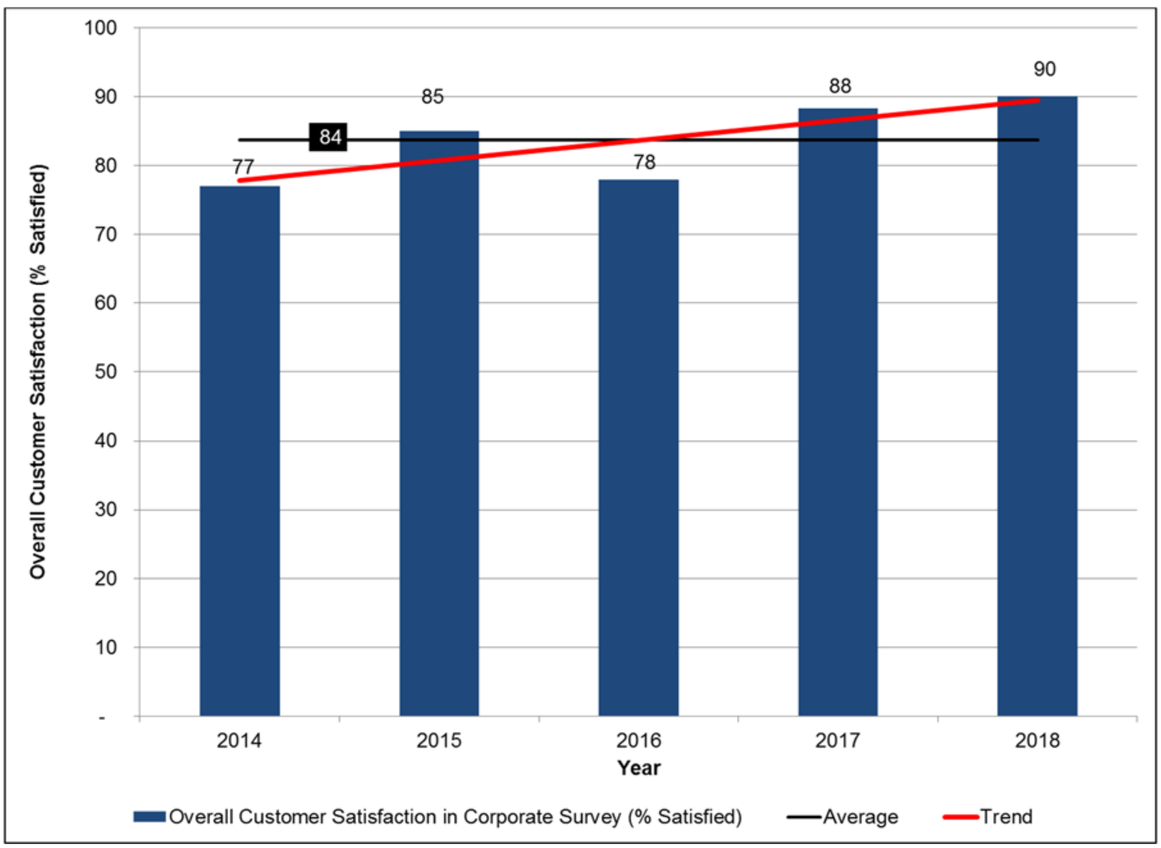

Figure 3 - Overall Customer Satisfaction, Corporate Survey (% satisfied)

Service Quality: Customer Delivery Point Performance, Standard Outliers as per cent of Total Delivery Points

Hydro One tracks customer DP performance as the percentage of group or individual outliers compared to the total number of DPs on the transmission system.

The percentage of standard outliers in 2018 increased by 0.6 percentage points compared to 2017, mainly due to more Weather, Equipment, and Foreign caused interruption (the 2018 Ottawa tornado event is excluded).

Hydro One's average performance over the past five years (2014-18) was 11.1 per cent and the performance trend is indicating a reduction in the number of delivery point outliers (see Figure 4).

Over the plan period, Hydro One aims to improve against its five-year average, targeting 10.8 per cent for its customer DP performance[10].

[10] In setting the targets for the rate period and the plan period for this measure, Hydro One examines its performance over the past ten years and makes a conservative performance forecast. For this reason, the targets are higher in future years relative to recent performance. However, the targets for 2022 and 2024 are both better than the historical five-year average.

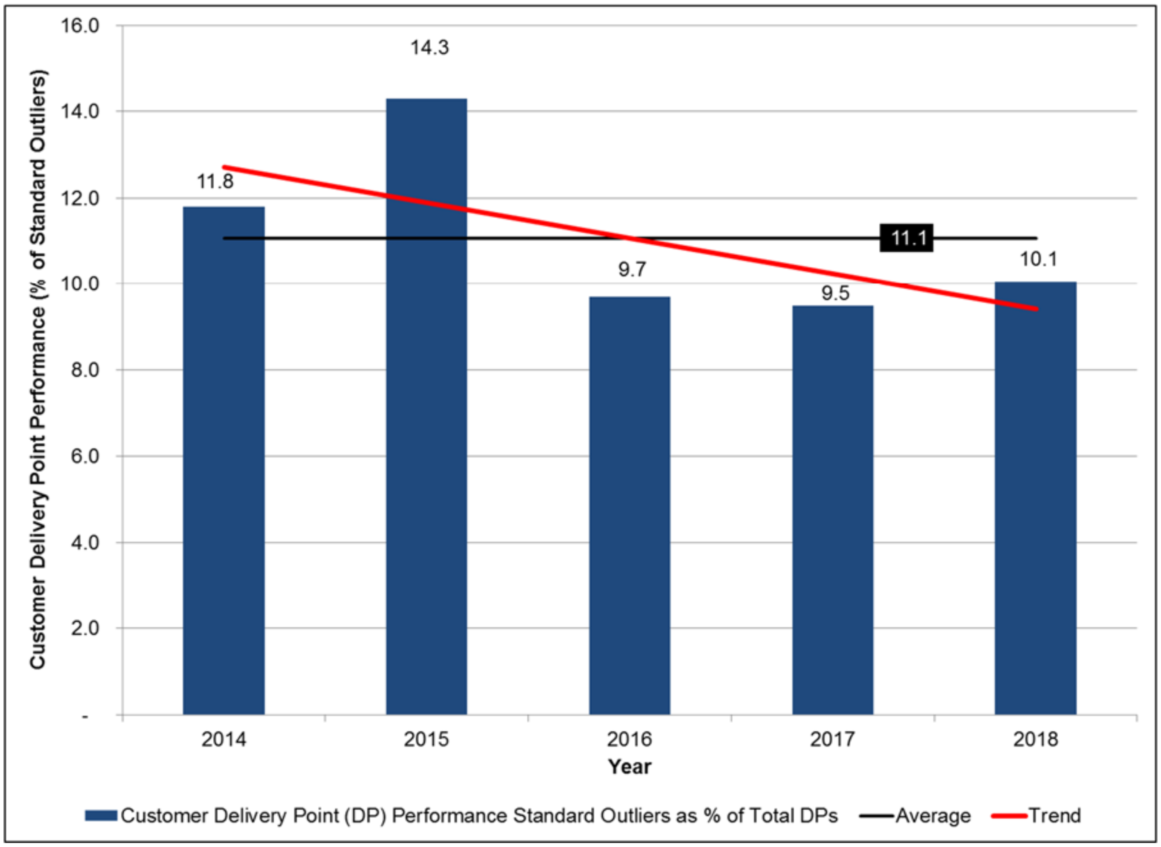

Figure 4 - Customer Delivery Point (DP) Performance, Standard Outliers as % of Total Delivery Points

Operational Effectiveness

Safety: Recordable Incident Rate (# of Recordable Injuries/Illnesses per 200,000 Hours Worked)

Hydro One tracks the number of work-related injuries or illnesses per 200,000 hours worked (recordable rate), which result in: 1) restricted work; 2) medical attention beyond first aid; 3) death or; 4) any other significant work-related injury or illness diagnosed by a physician or other healthcare professional and confirmed by a Hydro One Occupational Health Nurse. This measure only applies to employees of Hydro One and excludes contractors and the general public.

For 2018, Hydro One’s recordable rate was 1.1 incidents per 200,000 hours worked, representing a decrease of 0.1 incidents compared to 2017. Continued focus on improvements through the Journey to Zero initiatives, ensuring the Health, Safety and Environment Management System is effective through regular leadership reviews and audits; ongoing training and development; regular safety meetings; workplace safety observations and employee communications; and proactive engagement with employees and their representatives will assist Hydro One in achieving world-class safety performance.

Specific new initiatives for 2019 include a focus on improving Hydro One’s safety leadership skills to facilitate meaningful and effective safety conversations with employees, improving our skills development process for employees and apprentices and building on Human Success by identifying situations to minimize the likelihood of errors that my result in workplace injuries.

Hydro One's average performance over the past five years (2014-18) was 1.4 incidents per 200,000 hours worked, and Hydro One’s performance trend indicates a continued reduction in the recordable rate (see Figure 5).

Over the plan period, Hydro One aims to continue to improve against its historical average and is planning to reduce the recordable rate to less than one incident per 200,000 hours worked.

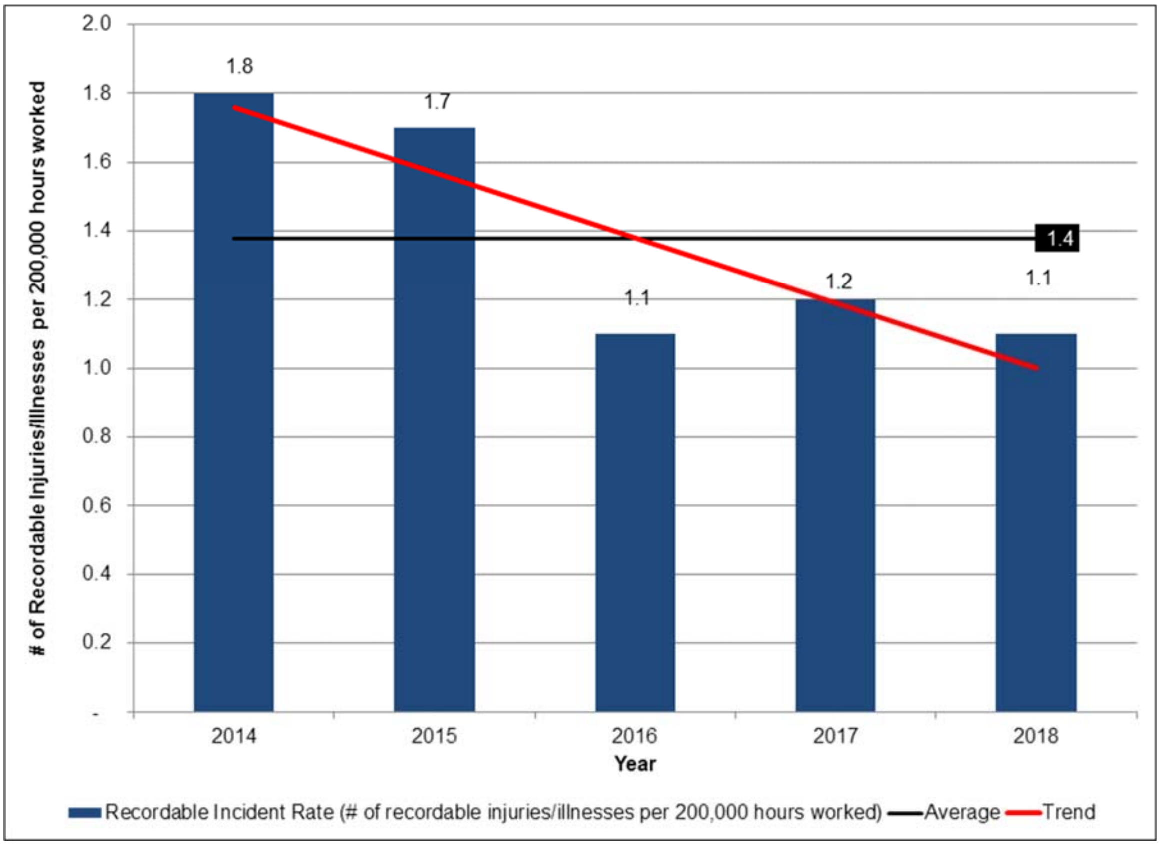

Figure 5 - Recordable Incident Rate

<u>*System Reliability: T-SAIFI-S, T-SAIFI-M, T-SAIDI, System Unavailability and Unsupplied Energy*</u>

Hydro One tracks and measures the reliability of its electricity transmission system using five distinct measures, defined as:

1. Transmission System Average Interruption Frequency Index – Sustained Interruption (“T-SAIFI-S”);
2. Transmission System Average Interruption Frequency Index – Momentary Interruption (“T-SAIFI-M”);
3. Transmission System Average Interruption Duration Index (“T-SAIDI”);
4. System Unavailability; and
5. Unsupplied Energy.

Hydro One removes extraordinary events from its reliability metrics that have had an “excessive” impact on the transmission system and that, in Hydro One’s assessment, strongly skew the historical trend of the measure. This exclusion threshold has been determined using a statistical method (log-standard deviation (β)) resulting in a threshold of 10,000 MW*min being used to exclude major unsupplied energy events from reliability metrics. Hydro One will apply this exclusion threshold to performance tracking and target setting starting in 2019. The historical reliability metrics below have been presented using the previous reliability metric approach and the one described above. Trends and averages relate to the previous reliability metric approach.

T-SAIFI-S is the average frequency of DP sustained interruptions – those greater than one minute in duration – and is used as an indicator of the average number of unplanned sustained interruptions that customers experienced per DP in the year.

The average number of sustained interruptions per delivery point in 2018 was 0.83, an increase in the index value of 0.18 or about 27 per cent compared to 2017, primarily due to more weather and equipment caused interruptions.

Hydro One’s average performance over the past five years (2014-18) was 0.63, and the performance is trending up, indicating an increase in the average number of sustained interruptions per delivery point (see Figure 6).

Over the plan period, Hydro One aims to improve against its historical average, targeting 0.50 for T-SAIFI-S.

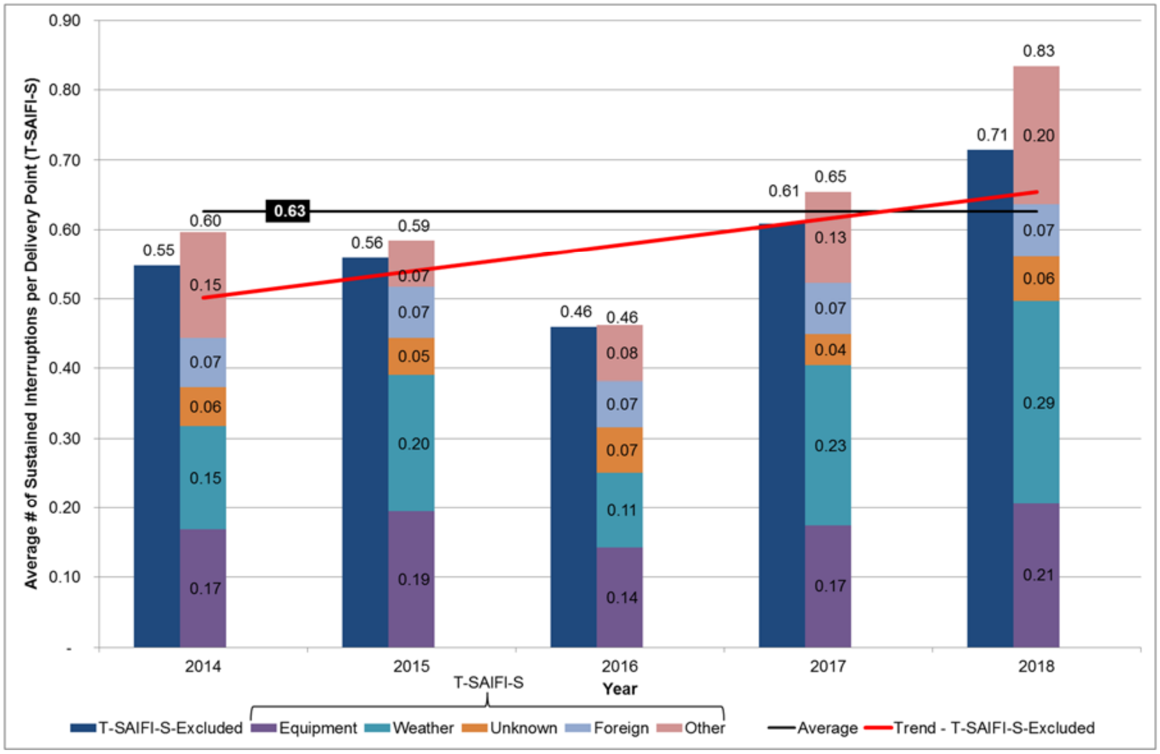

Figure 6 - Transmission System Average Interruption Frequency Index – Sustained Interruption

T-SAIFI-M is the average frequency of DP momentary interruptions – those less than one minute in duration – and is used as an indicator of the average number of unplanned momentary interruptions that customers experience per DP in the year.

The average number of momentary interruptions per DP in 2018 was 0.50, an increase in the index value of 0.03 or about 6 per cent compared to 2017, primarily due to more weather caused interruptions.

Hydro One's average performance over the past five years (2014-18) was 0.46 interruptions per DP, and the performance trend is relatively flat (see Figure 7).

Over the plan period, Hydro One aims to improve against its historical average, targeting 0.45 for T-SAIFI-M.

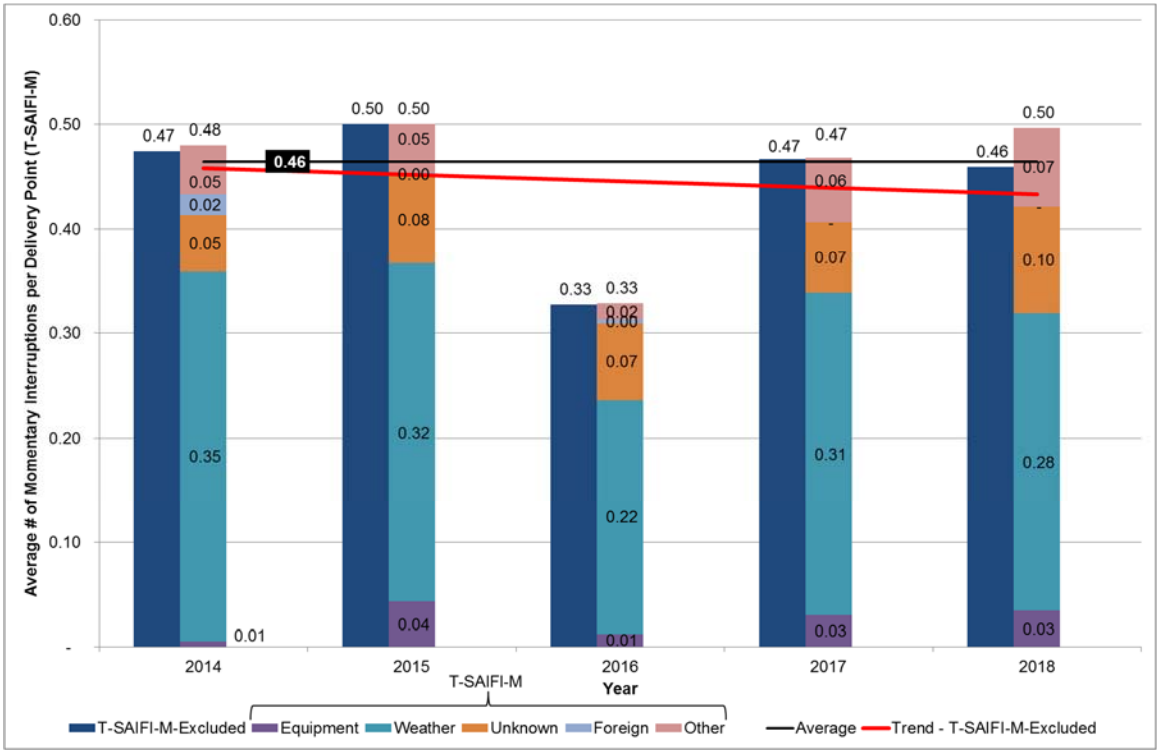

Figure 7 - Transmission System Average Interruption Frequency Index – Momentary Interruption

T-SAIDI is the average duration of sustained DP interruptions – those greater than one minute in duration – and is used as an indicator of the average minutes of unplanned interruptions that customers experience per DP in the year.

The average duration of sustained interruptions per DP in 2018 was 69.9 minutes, an increase of 27.1 minutes or about 63 per cent compared to 2017. The result in 2018 was driven by a large freezing rain event on April 14th, an extreme wind storm in southern Ontario on May 4, 2018, outages impacting eastern Toronto as a result of events in proximity to Hearn SS and Gerrard TS on Jan 8, 2018 and Feb 10, 2018 and the Finch TS T2 failure on July 27-28, 2018.

Hydro One's average performance over the past five years (2014-18) was 54.9 minutes (see Figure 8) and the performance is trending up, indicating an increase in the average minutes of interruptions per delivery point. T-SAIDI performance can vary significantly from year to year due to following reasons:

- limited number of DPs;
- a small number of events which can contribute most of the index;
- major events which had occurred and will happen randomly; and
- radially supplied DP performance, which can vary significantly due to lack of alternative source.

Based on the uncertainty in the performance on this measure year-over-year, the future targets are set based on multiple year averages.

Over the plan period, Hydro One aims to improve against its five-year average, targeting 32.0 minutes for T-SAIDI.

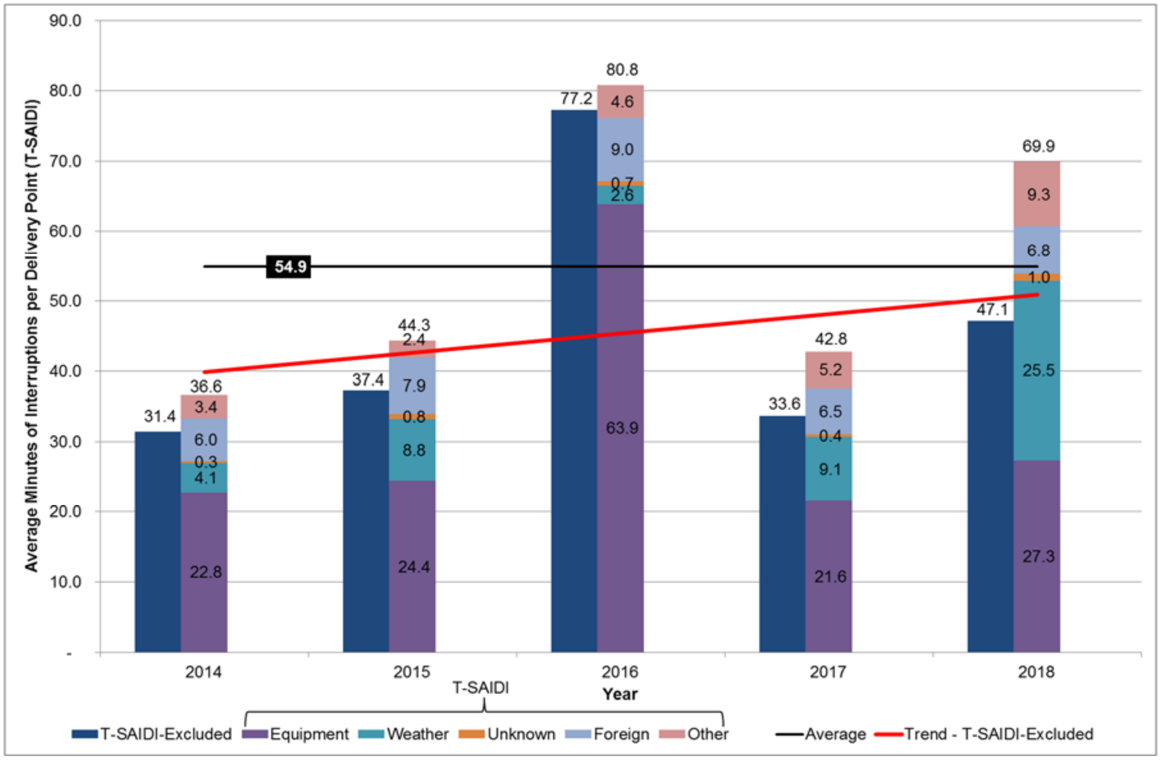

Figure 8 - Transmission System Average Interruption Duration Index (minutes)

System unavailability examines the unavailability of transmission lines and major transmission station equipment, due to direct automatic or forced manual outages caused by factors such as defective equipment, adverse weather, adverse environment, foreign interference and human element. This measure does not consider the subordinate outages of healthy transmission equipment removed from service as a result of an outage caused by other equipment. The information derived from monitoring this measure is trended over time and helps influence business decisions that affect the reliability of transmission equipment. This measure is specifically defined to enable comparison with all-Canada averages from all transmission utilities which participate in the Equipment Reliability Information System program of the Transmission Consultative Committee on Outage Statistics at the Canadian Electricity Association.

System unavailability for 2018 was 0.83 per cent, and 0.15 percentage points higher compared to 2017. Increases in lines unavailability in 2018 were driven to a large extent by tornado damage on a circuit and the need to repair two separate faulted cable circuits. Increases in the unavailability of stations equipment in 2018 were driven to a large extent by the unavailability of high voltage capacitors due to issues with the capacitor itself or the capacitor breaker.

Hydro One's average performance over the past five years (2014-18) was 0.67 per cent system unavailability and the performance trend indicates an increase in system unavailability over the past five years (see Figure 9).

Over the plan period, Hydro One aims to improve against its five-year average, targeting 0.44 per cent for system unavailability.

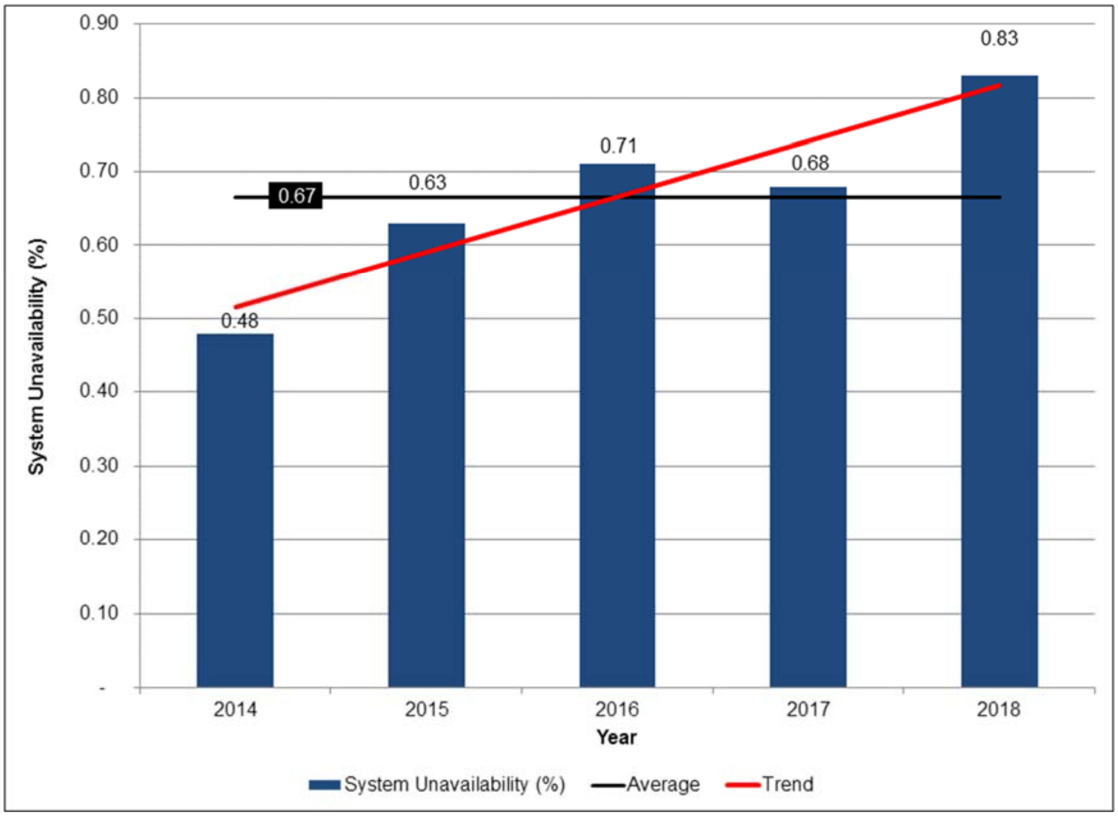

Figure 9 - System Unavailability (in %)

Unsupplied Energy is the total energy not supplied to customers during the year, measured in system minutes, due to unplanned interruptions to all delivery points. This measure is normalized against the system peak to make the performance comparable to that of other utilities.

Unsupplied Energy for 2018 was 19.5 system minutes, higher by approximately 6 minutes or about 48 per cent compared to 2017 primarily due to more weather-caused interruptions such as a large freezing rain event on April 14th and large wind event on May 4th.

Hydro One's average performance over the past five years (2014-18) was 13.6 system minutes of unsupplied energy, and the performance trend is showing a deterioration or an increase in unsupplied energy over the past five years mostly attributable to 2018 (see Figure 10).

Over the plan period, Hydro One aims to improve against its five-year average, targeting 8.8 system minutes for unsupplied energy.

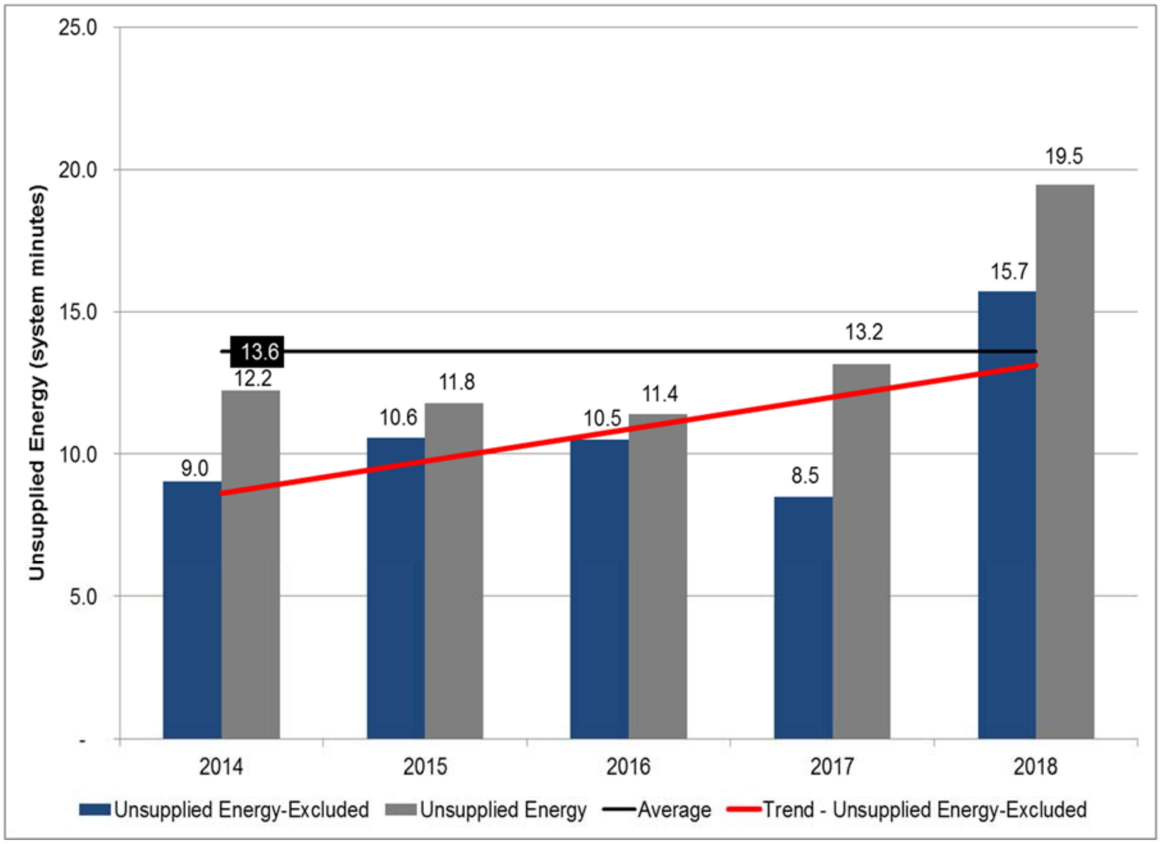

Figure 10 - Unsupplied Energy (System Minutes)

T-SAIFI-S, T-SAIFI-M, T-SAIDI, System Unavailability and Unsupplied Energy, Additional Discussion

While equipment unavailability doesn't necessarily lead to interruptions due to redundancy on Hydro One's transmission system, it is a leading indicator of future reliability erosion. Equipment reliability risk similarly is an indicator of the potential for future reliability issues. Reliability risk provides a comparable illustration of the potential for reliability issues over time. Reliability risk assessment is a proactive measure to mitigate risks before reliability performance starts to deteriorate and negatively impact customers.

To improve reliability and meet the targets over the test year period, Hydro One commissioned a number of third party expert studies to validate Hydro One's approach to managing specific types of transmission assets (see TSP Section 1.4). Hydro One has included specific projects in the Business Plan to replace equipment due to asset condition and performance. Investments to replace some of these assets are described in Investment Summary Documents, including but not limited to:

- Air Blast Breaker Replacement Project – SR-01;
- Line Replacements – SR-19, SR-20;
- Transformer Replacements – SR-03, SR-05; and
- Protection Replacements – SR-07, SR-10.

Asset & Project Management: Transmission System Plan Implementation Progress

In-service capital additions are tracked and reported in a manner consistent with the regulatory requirements of the transmission business, and reported as a percentage value relative to the transmission plan. For 2018, the TSP implementation achieved 99 per cent of the planned in-service capital expenditures, including the OEB carry-forward variance.

Hydro One's average performance over the past five years (2014-18) was 99 per cent of the TSP, and the company's past performance trend is flat (see Figure 11).
Over the plan period, Hydro One aims to improve against its five-year average, and complete 100 per cent of the TSP.

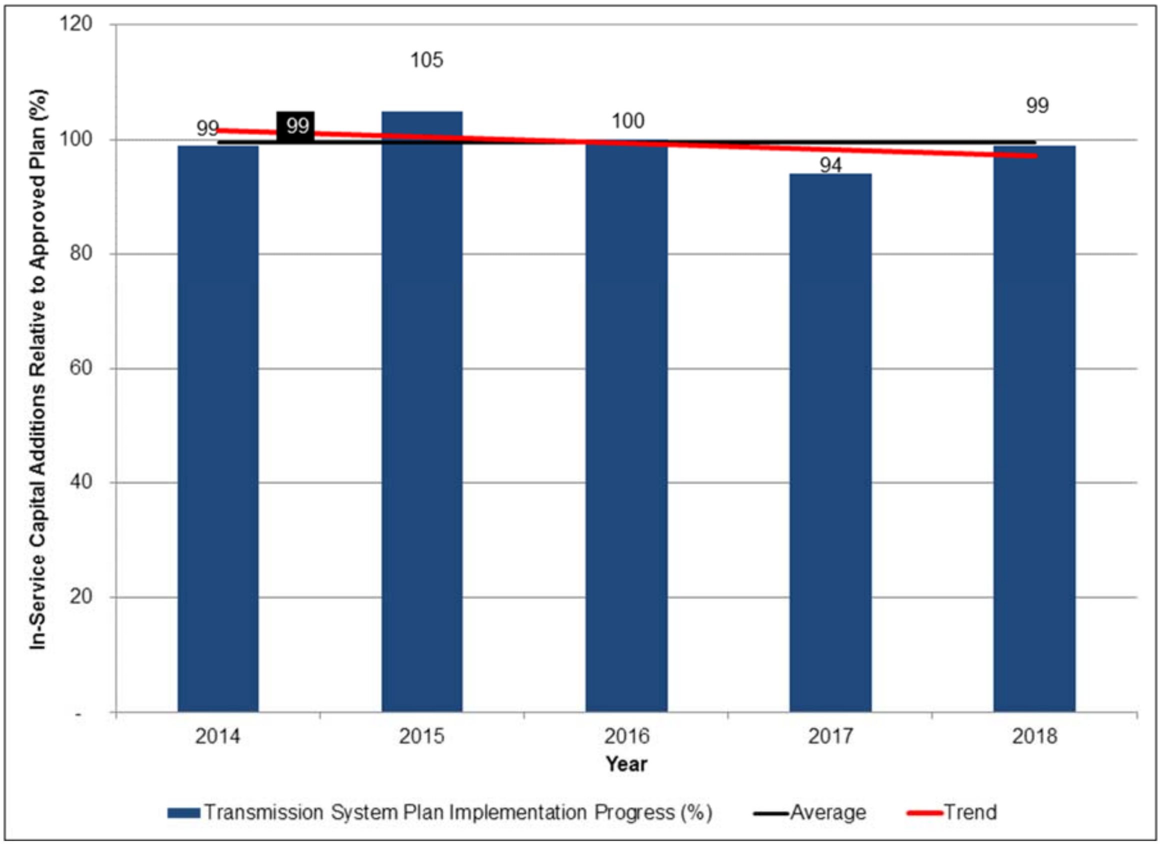

Figure 11 – Transmission System Plan Implementation Progress (in %)

Asset & Project Management: Capital Expenditures as per cent of Budget

Hydro One measures the progress of its capital expenditures towards the approved plan as the ratio of actual total capital expenditures to the total amount of planed capital expenditures.

For 2018, the company's capital expenditures were 97% of budget and lower by 3 percentage points compared to 2017. The result in 2018 was mainly due to delays of work to 2019 on various projects including the underground cable circuit investment from Leaside to Main transmission station and deferred projects to future years including the Integrated System Operations Centre.

Hydro One's average performance over the past five years (2014-18) was on budget (100%), and Hydro One's past performance indicates an upward trend in the percentage of capital expenditures relative to the approved budget (see Figure 12). This is mainly due to timing of capital expenditures on large Inter Area Network Transfer Capability projects.

Over the plan period, Hydro One aims to improve against its five-year average, and meet 100 per cent of the approved plan.

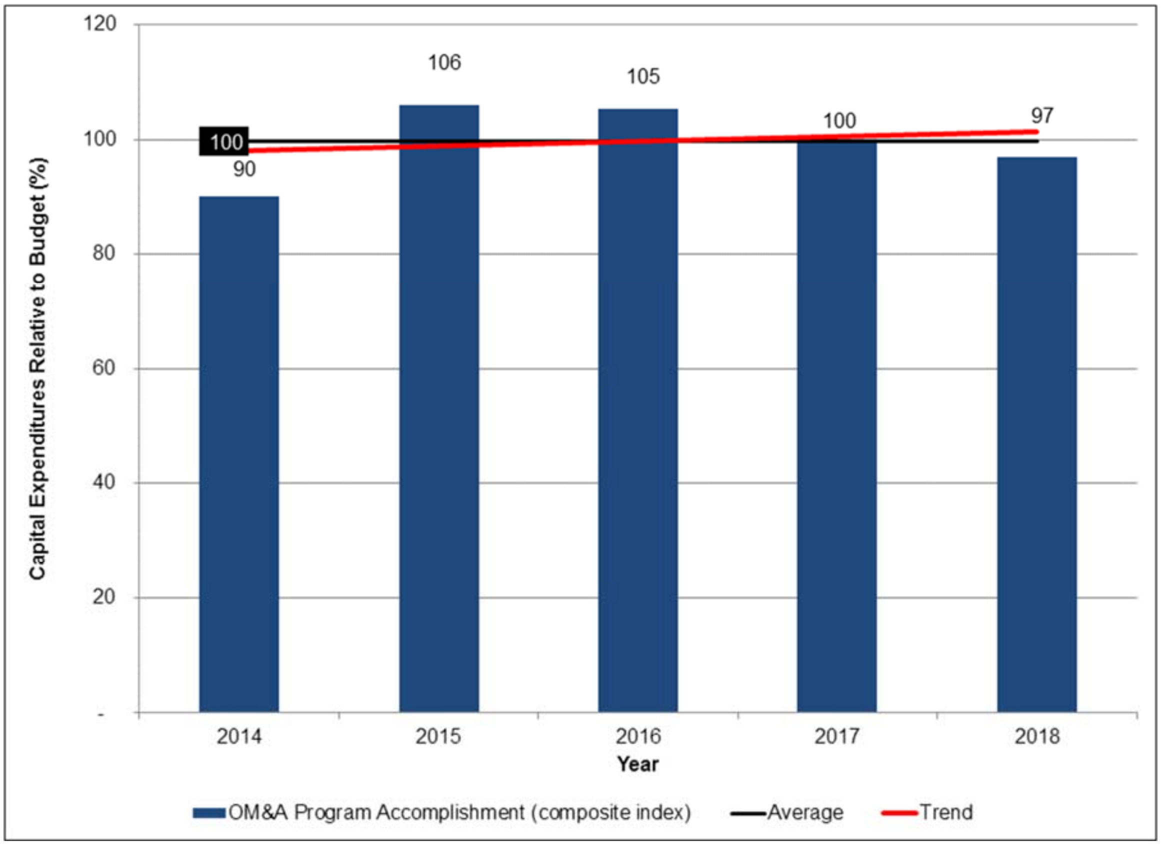

Figure 12 – Capital Expenditures as % of Budget

Asset & Project Management: OM&A Program Accomplishment (Composite Index)

For 2018, Hydro One's OM&A Program Accomplishment composite index value was 108.0, compared to 107.7 in 2017. The increase over the last two years is mainly due to an improvement in the accomplishment of power equipment preventive maintenance, and an increase in the volume of testing and retro-filling of PCB-contaminated equipment.

Hydro One's average index value over the past four years (2015-18) was 102.9, and Hydro One's past performance indicates an upward trend (see Figure 13). This is mainly due to improved preventative maintenance planning processes.

Over the plan period, Hydro One is targeting a composite index value of 100.

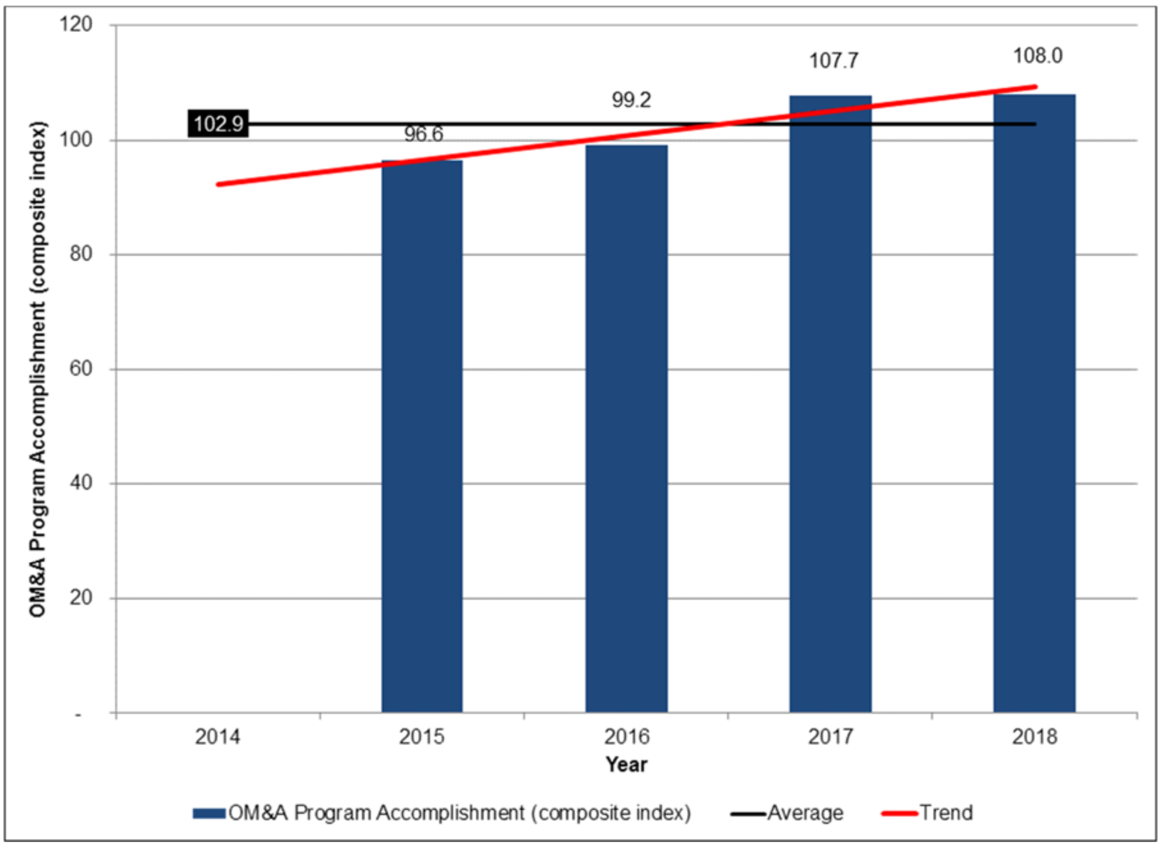

Figure 13 - OM&A Program Accomplishment (Composite Index)

Asset & Project Management: Capital Program Accomplishment (Composite Index)

For 2018, Hydro One's Capital Program Accomplishment composite index value was 116.0, compared to 87.8 in 2017, an improvement resulting from full completion of the planned steel structure re-coating and insulator replacements, improved rate of completion of the shield wire replacements and higher purchased number of spare transformers compared to budget, partially offset by lower than planned completion of wood pole replacements.

Hydro One's average index value over the past four years (2015-18) was 96.4, and Hydro One's past performance indicates a slight upward trend (see Figure 14).

Hydro One plans to stabilize its five-year average, targeting an index value of 100 over the plan period.

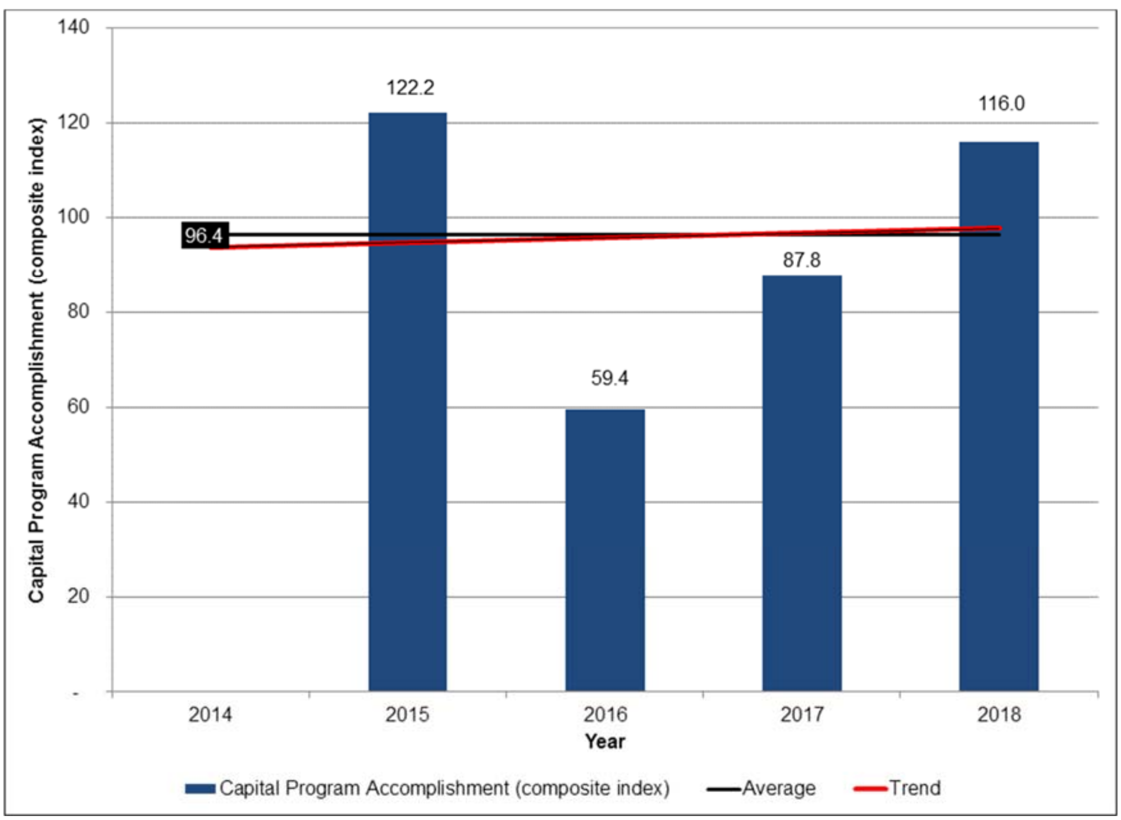

Figure 14 - Capital Program Accomplishment (Composite Index)

Cost Control

Hydro One measures cost control using four OM&A and capital measures:

1. Total OM&A and Capital Expenditures ("CapEx") as a percentage of Gross Fixed Asset Value;
2. OM&A as a percentage of Gross Fixed Asset Value;
3. Line Clearing Cost per kilometer; and
4. Brush Control Cost per kilometer.

Total OM&A and capital expenditure relative to the gross fixed asset value in 2018 was 7.7 per cent, or 0.2 percentage points lower compared to 2017, due to a higher growth in gross fixed asset value compared to OM&A and capital expenditure. Several large capital projects were placed in-service in 2018 such as the Clarington transmission station, Horning transmission station, NRC transmission station and St. Isidore transmission station.

Hydro One's average performance over the past five years (2014-18) was 8.3 per cent, and performance is moderately upward, mainly due to required reinvestment and maintenance in gross fixed assets (see Figure 15).

Over the plan period, Hydro One aims to improve on results compared to its historical average, targeting 7.0 per cent.

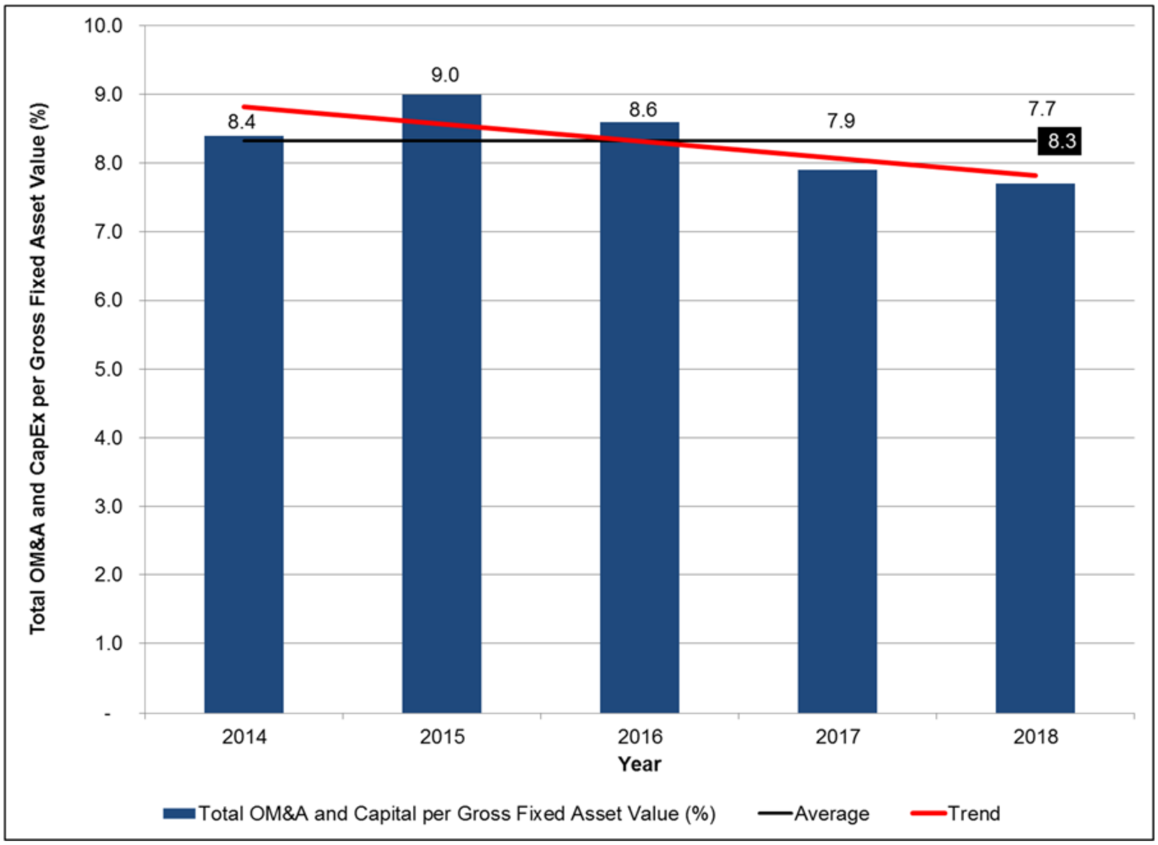

Figure 15 - Total OM&A and Capital per Gross Fixed Asset Value (as %)

OM&A expenditure per gross fixed asset value in 2018 was unchanged from 2017 at 2.3 per cent. The lower OM&A expenditure ratio compared to past years was mainly due to a reduction to the provision for payments in lieu of property taxes following a favourable reassessment of the regulations and estimates related to the liabilities lower property taxes, insurance proceeds received for equipment failures at the Fairchild and Campbell transmission stations and lower corporate support costs.

Hydro One's average performance over the past five years (2014-18) was 2.5 per cent. The OM&A ratio is trending downwards, due to decreased levels of operating and maintenance expenditures (see Figure 16).

Over the plan period, Hydro One aims to improve on results compared to its historical average, and is targeting 1.5 per cent for the OM&A ratio.

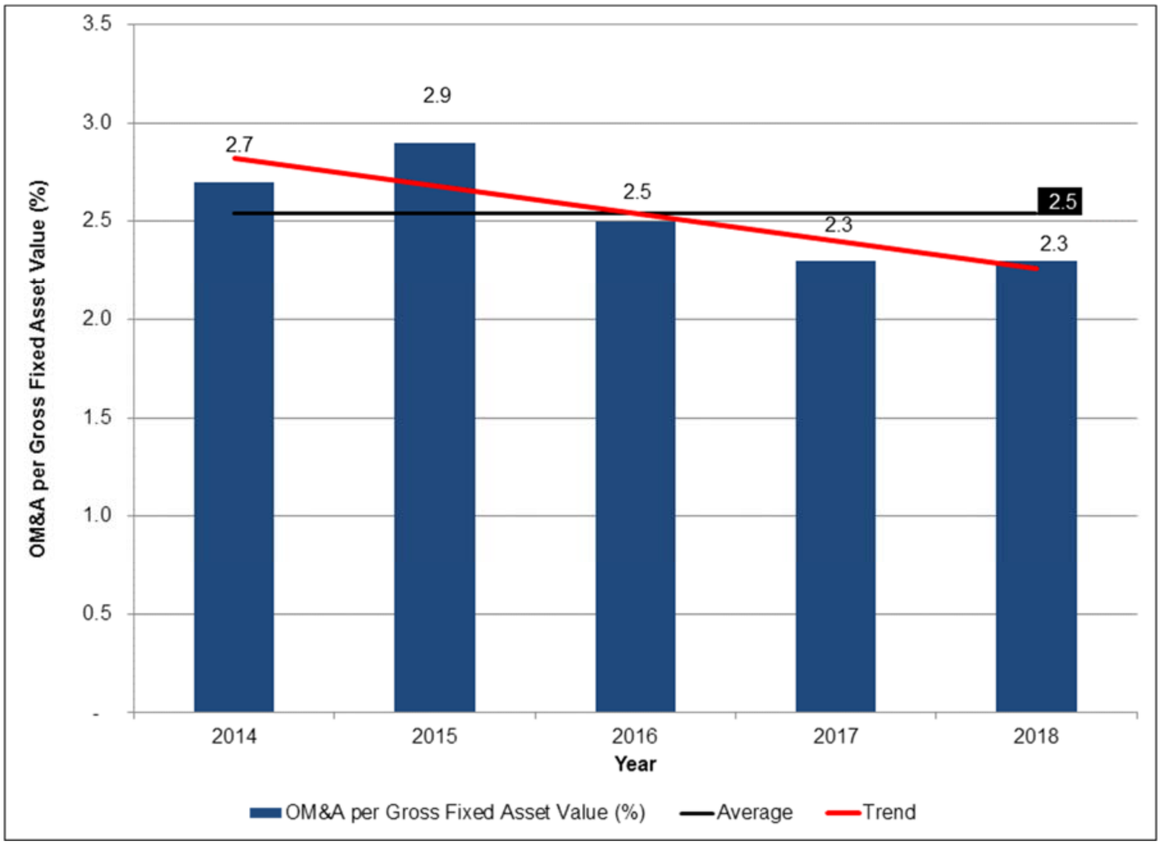

Figure 16 - OM&A per Gross Fixed Asset Value (as %)

Hydro One measures the cost of the line clearing program per kilometre cleared annually. In recent years, Hydro One's vegetation management activities have migrated to operating near their optimal levels in the years 2014-2018, using a six-year cycle in the South, Central, and East regions and an eight-year cycle in North. During these years (2014-2018) the main objective of the program was to get ahead on the backlog created during the period 2008-2013. The focus has also been on gaining greater control of the corridors by bringing tree edges back to the original design specifications. This has directly improved transmission system reliability by decreasing tree encroachments and reducing future maintenance costs. Additionally, Hydro One is experiencing a spike in the volume of work in urban corridors in areas including but not limited to the Greater Toronto Area, Ottawa, Burlington, and Waterloo, where previously, vegetation was not adequately addressed due to community pressure to preserve the trees. Zero tolerance enforcement for non-compliance to NERC FAC-003 Standard regarding minimum clearances for vegetation growth, has led Hydro One to revise its urban vegetation management planning and execution strategy.

For 2018, Hydro One's cost per kilometer of line cleared was $2,797, an increase of $697 or about 33 per cent compared to 2017, primarily due to the factors discussed below (see Figure 17).

Hydro One's average line clearing cost over the past five years (2014-18) was $2,318 per kilometer, and the average annual number of kilometers cleared over the same period was 3,200 kilometers (including the over-accomplishment years 2014 and 2015). Hydro One's past performance indicates an increasing trend in the cost per kilometer, mainly attributable to the increase in work required to bring back corridors to design width across the province and increased work requirements to maintain urban corridors based on the Transmission industry and NERC standards. Additionally, there was a NERC violation in the GTA area that caused an outage on a 230kV BES line. Because of that, field resources took extra caution on all the corridors planned for 2018 to make sure they get as much clearance as possible to the design width standards.

Over the plan period, Hydro One aims to improve against its five-year average, targeting $2,100 per kilometer of line cleared, and expects to clear 3,000 kilometers of line on average annually.

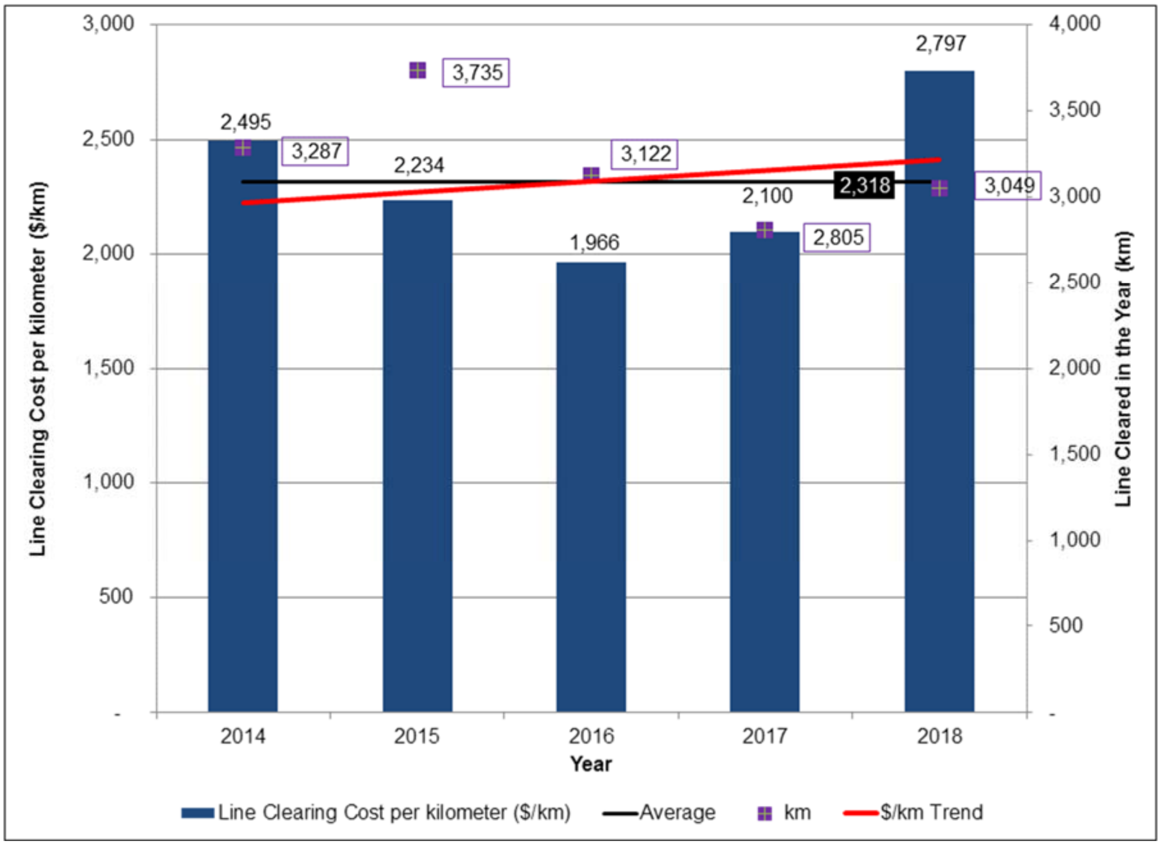

Figure 17 - Line Clearing Cost per kilometer and Number of kilometers Cleared Annually

Hydro One measures the cost of its brush control per hectare completed in the year. For 2018, Hydro One's brush control cost was $1,539 per hectare, completing 12,850 hectares, compared to $1,356 per hectare in 2017 when it completed 12,040 hectares. Similar to the line clearing program, brush control programs are also being managed near optimal levels, using the same cycles as line clearing, by minimizing program deferrals.

Hydro One's average brush control cost over the past five years (2014-18) was $1,525 per hectare, and the average annual number of hectares completed over the same period was 12,203 hectares. Hydro One's performance trend indicates a modest decrease in the cost per hectare, mainly attributable to increased use of herbicide and mechanical means to control ROW areas (see Figure 18). Hydro One continues to invest in vegetation management on all of the transmission corridors to maintain adherence to design standards and decrease backlog conditions.

Over the plan period, Hydro One is targeting $1,608 per hectare completed (including cost escalations due to inflation) and expects to complete 12,500 hectares on average annually.

Unit costs for line clearing for the rate period (2020 to 2022) are forecasted to be higher than the five-year average, but generally lower during the plan period (2020 to 2024). Unit costs for brush control over both the rate period and the plan period are forecasted to be higher than the five-year average. Hydro One's focus has been on gaining greater control of its corridors by bringing tree edges back to the original design specifications, making progress on backlogs, and ensuring its activities operate near their optimal cycle. This work is expected to continue through the plan period and is the primary driver for the forecast costs.

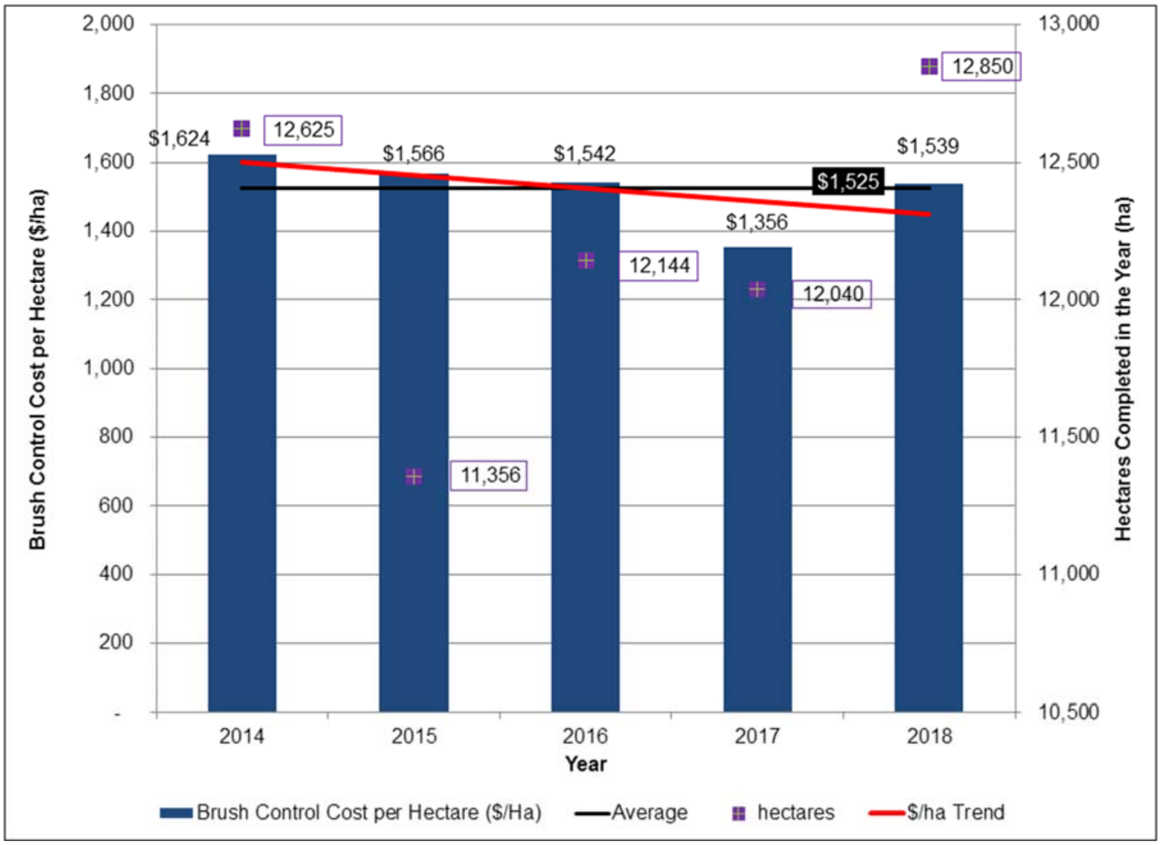

Figure 18 - Brush Control Cost per Hectare and Hectares Completed Annually

Public Policy Responsiveness

__Renewable Energy: On-Time Completion of Renewables Customer Impact Assessments (as per cent)__

For transmission-connected generators, Hydro One completes customer impact assessments and measures its performance in the successful completion of these assessments against a period of 150 days. In 2018, for the fifth consecutive year, Hydro One completed 100 per cent of the customer impact assessments within the allotted time (see Figure 19). Hydro One attributes its consistent performance mainly due to its well defined internal processes and closely coordinating and managing these activities with the Independent Electricity System Operator ("IESO").

Over the plan period, Hydro One aims to maintain its historical performance average, and is targeting 100 per cent on-time completion of renewables customer impact assessments.

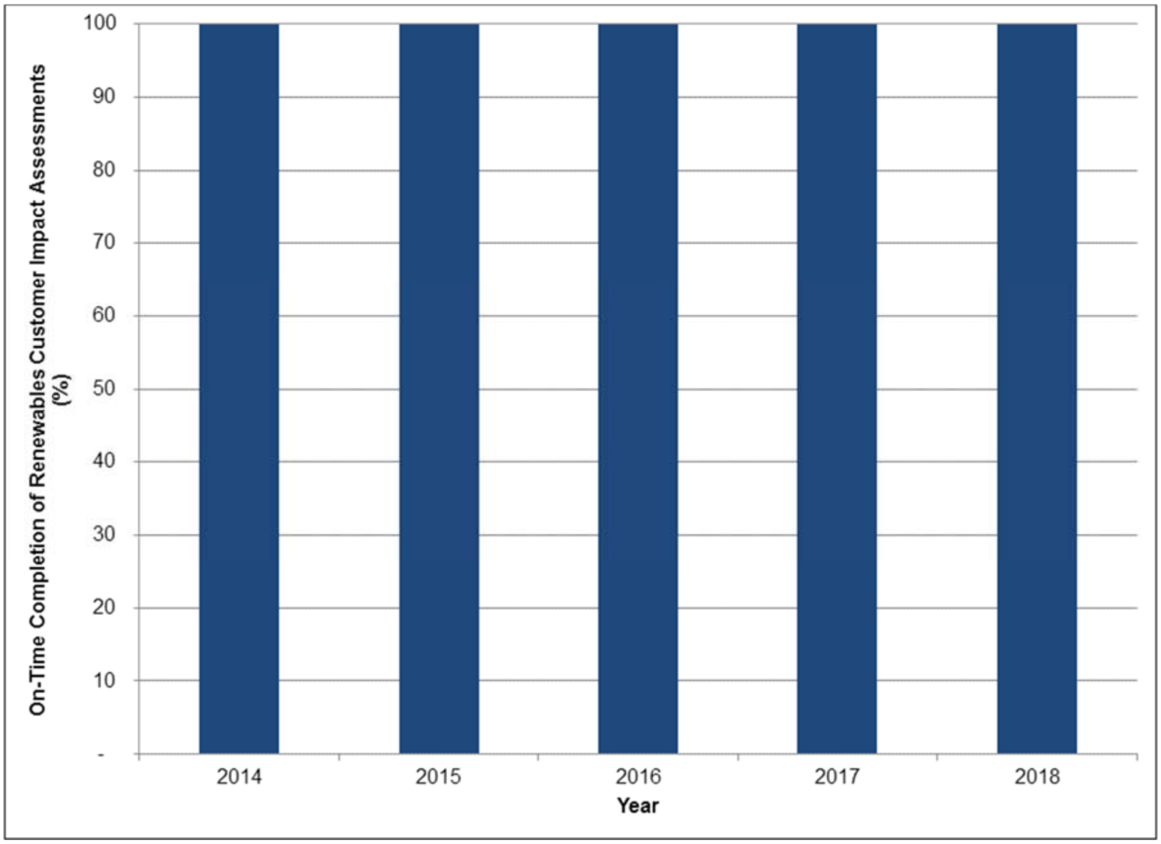

Figure 19 - On-Time Completion or Renewables Customer Impact Assessment (as %)

Regional Infrastructure: Regional Infrastructure Planning Progress (per cent of Deliverables Met)

To drive performance relative to the Public Policy Responsiveness outcome, Hydro One measures the performance of its Regional Infrastructure Planning process. The Regional Infrastructure Planning process was established by the OEB in the third quarter of 2013.

Hydro One measures the percentage of deliverables completed within the prescribed timelines in the Transmission System Code, which includes certain deliverables such as plans, Regional Planning reports, and LDC Planning Status letters for their rate applications. These reports are published on the Hydro One website.

In 2018, for the fifth consecutive year, Hydro One met 100 per cent of its regional infrastructure planning deliverable obligations, within the allotted time (see Figure 20). Hydro One also files an Annual Status Report with the OEB on November 1 of each year. Hydro One attributes its consistent performance mainly due to its well defined process and closely coordinating and managing these activities with the LDCs and IESO, to meet the mandatory obligations.

Over the plan period, Hydro One aims to maintain its historical performance average, and is targeting 100 per cent.

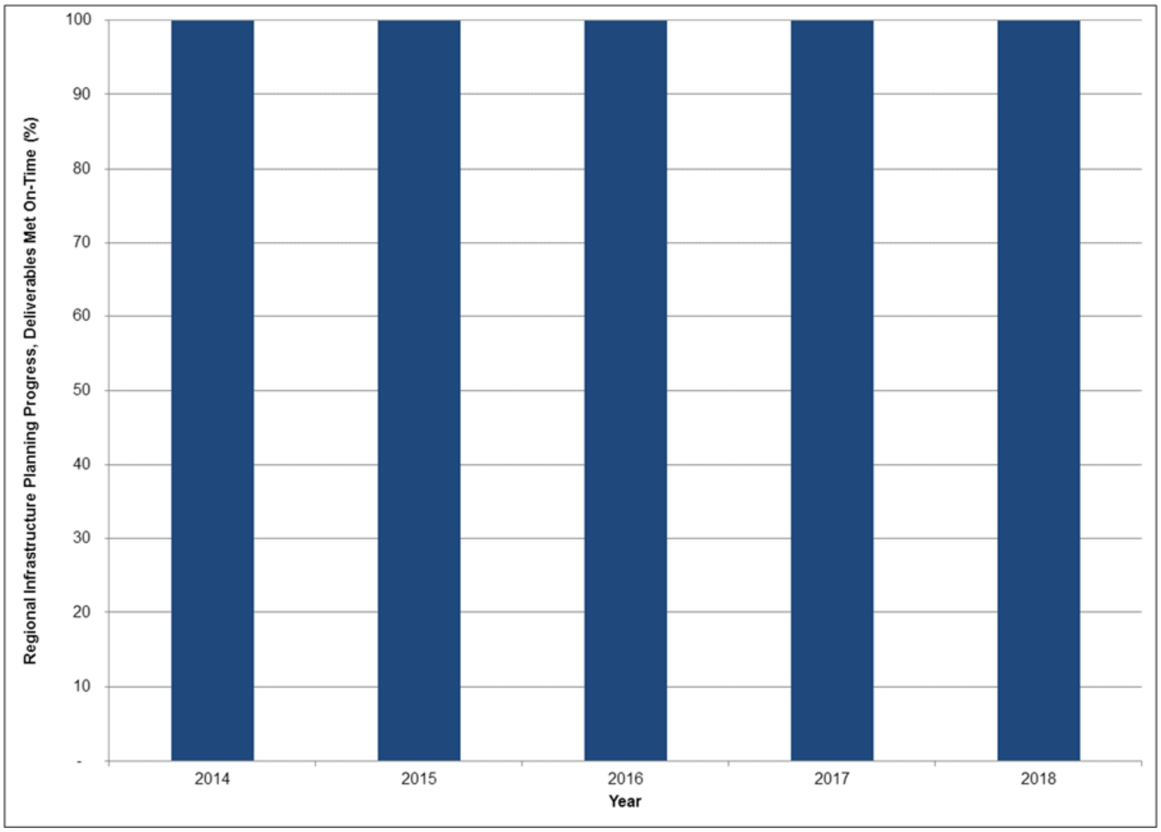

Figure 20 - Regional Infrastructure Planning Progress (% of Deliverables Met)

Long-Term Energy Plan ("LTEP"): End-of-Life Right-Sizing Assessment Expectations Met

This is a new measure introduced in response to the Decision, which qualitatively measures and tracks Hydro One's public policy responsiveness. For further details on this measure, see TSP Section 1.5.2.

In 2018, Hydro One met 100% of its End-of-Life Right Sizing Assessment Expectations.

Over the plan period, Hydro One is targeting to continue a "Met" result in all years.

Financial Ratios

Liquidity: Current Ratio

For 2018, Hydro One reported a current ratio for the transmission segment of 0.18, representing a minimal decrease from 2017 and about a 35 per cent decrease compared to 2016. The 2018 result indicates that for every one dollar of current liabilities, Hydro One had $0.12 in current assets. Current assets are defined as cash or cash equivalents to be converted to cash within the year and which can be used to fund daily operations and pay ongoing expenses. Current liabilities are defined as debt or other financial obligations that become due within the year.

Hydro One's average current ratio over the past five years (2014-18) was 0.25, and is trending downwards, reflecting a decrease in the amount of cash or cash equivalents (see Figure 21). The trend is largely attributable to the high current ratios in 2014 which was mainly due to a positive balance in the inter-company demand facility. Subsequently, the current ratio decreased to 0.13 in 2015 and subsequent years. Due to the nature of this measure, Hydro One has not provided a forecast outlining future financial performance expectations.

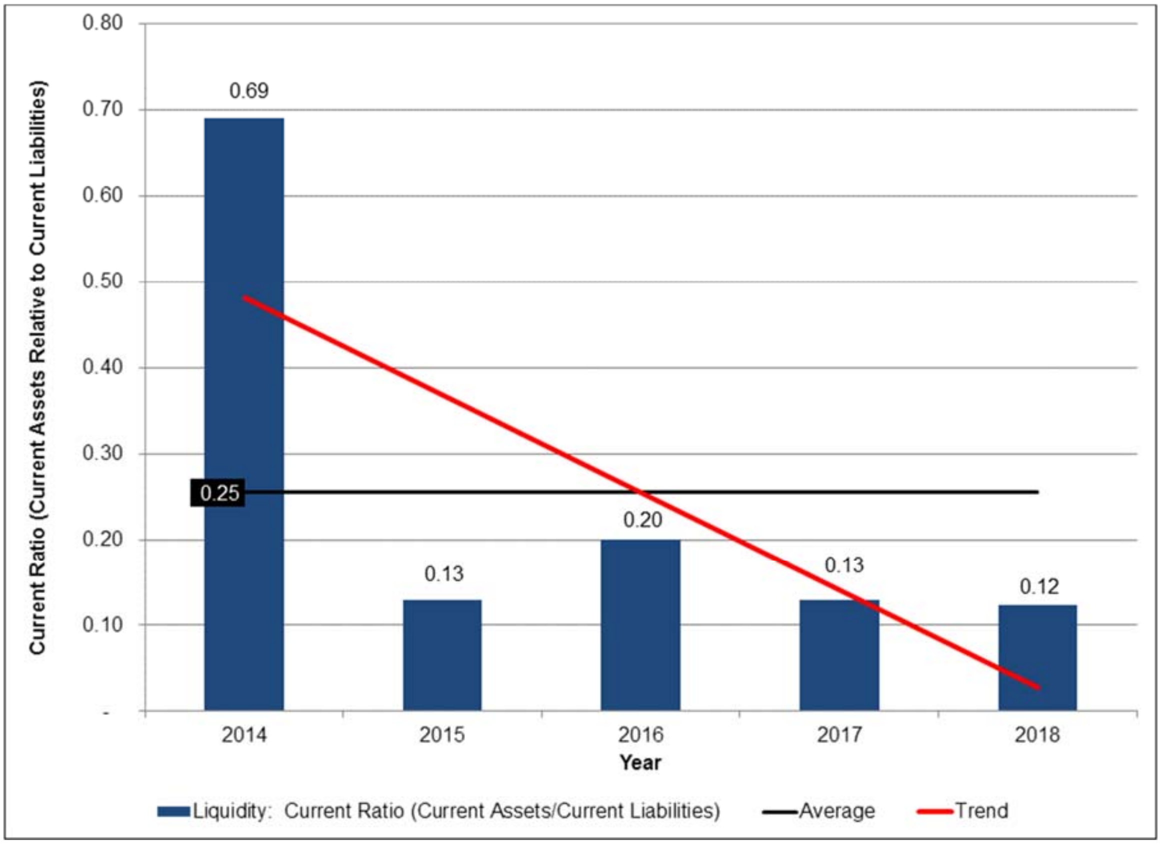

Figure 21 - Liquidity: Current Ratio

<u>Leverage: Total Debt to Equity Ratio</u>

Hydro One's total debt to equity ratio as measured for its transmission segment was 1.53 in 2018, representing an increase of about 4 per cent compared to 2017. The debt to equity ratio is a measure of Hydro One's financial leverage and serves to identify the ability to finance assets and fulfill creditor obligations. The OEB-deemed capital structure is 60 per cent to 40 per cent debt to equity (a ratio of 1.50).

Hydro One's average debt to equity ratio over the past five years (2014-18) was 1.40, and is trending upwards in order to match the OEB-deemed ratio of 1.50 (see Figure 22). The average debt to equity ratio was previously less than the deemed structure of 1.50 largely due to a low dividend payout for the business, as directed by its prior sole shareholder, the Province of Ontario. After Hydro One's Initial Public Offering in 2015, its debt to equity ratio was adjusted to conform more closely to the OEB-deemed capital structure, and company management has stated publicly that it intends to maintain this ratio at or around that level.

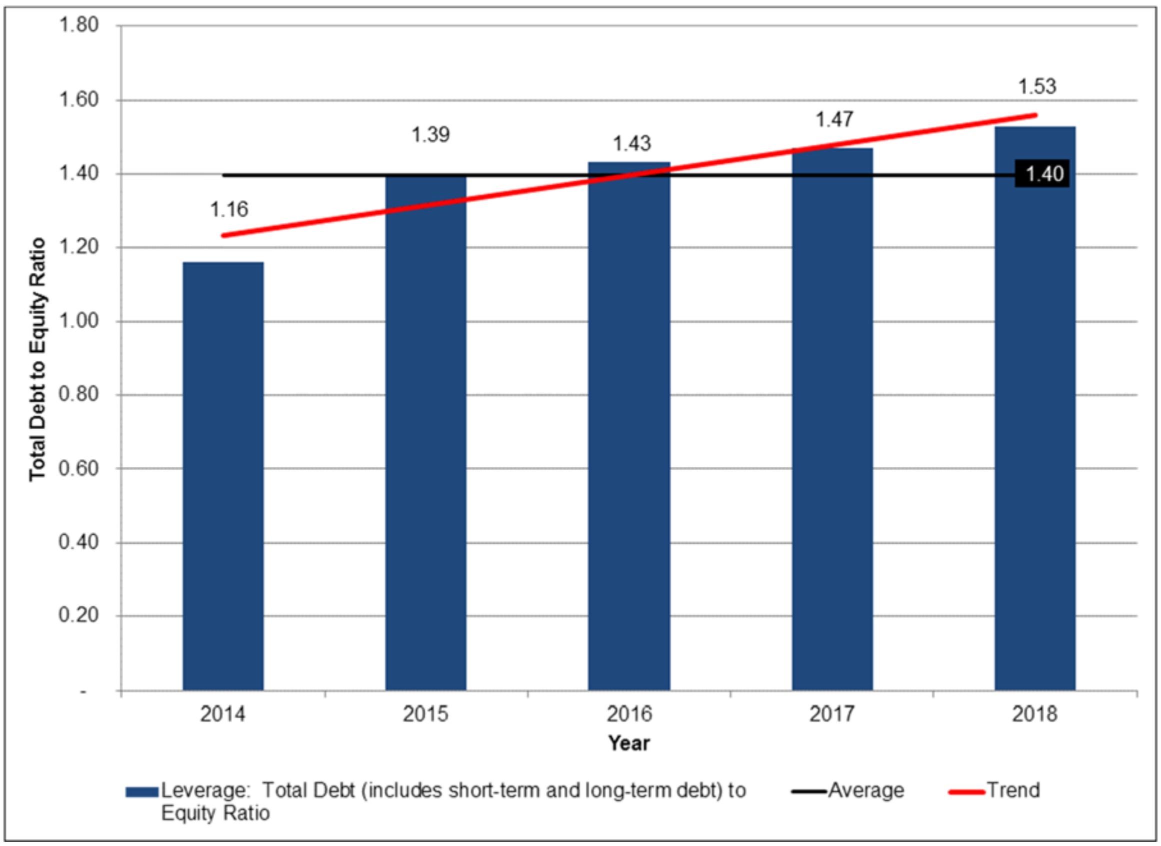

Figure 22 - Leverage: Total Debt to Equity Ratio

__Profitability – Achieved Regulatory Return on Equity__

Hydro One's 2018 achieved regulatory return on equity ("ROE") was 9.63 per cent for its transmission segment, against an OEB-deemed ROE of 8.98 per cent.

Hydro One’s average achieved regulatory return on equity over the past five years (2014-18) was 10.55 per cent and is trending down (see Figure 23).

Due to the nature of this measure, Hydro One has not provided a forecast outlining future financial performance expectations, except that the company strives to achieve the OEB deemed return.

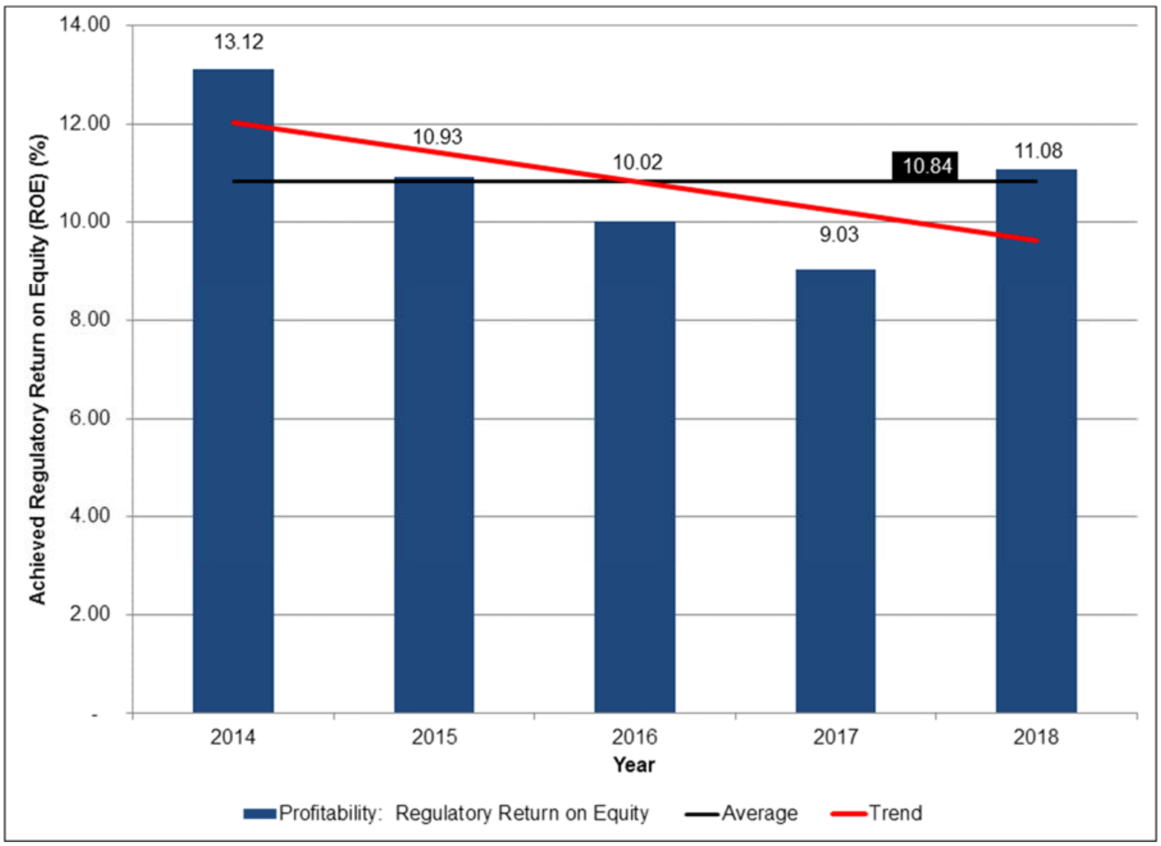

Figure 23 - Achieved Regulatory Return on Equity (ROE)

Summary

The evolved Transmission Scorecard and measures presented herein reflect Hydro One’s response to the Decision and provide continuity with Hydro One’s previously filed Transmission Scorecard. As directed in the Decision, and as evidenced through the evolved Transmission Scorecard and supporting Performance Reporting Governance Framework (TSP Section 1.5, Attachment 1), Hydro One has continued to develop its performance management system and scorecard to reflect the OEB's observations and determinations. In doing so, Hydro One has considered the merits of implementing measures that reflect the overall business and which are expected to positively impact outcomes. In the sections above, Hydro One summarized the methods and approaches it used to select measures for the evolved Transmission Scorecard, and what it believes are the expected merits and outcomes. Additionally, these measures were influenced by internal and external sources that include Hydro One's past performance management measures, benchmarking studies, scorecards, and measures of other utilities in the public domain to align with the key considerations presented in the Handbook. Hydro One's targeted performance outcomes, as reflected in the evolved Transmission Scorecard, will assist Hydro One in transparently monitoring and measuring its performance relative to these outcomes.

Performance Reporting Governance Framework

Distribution & Transmission

January 2019

Contents

Performance Measurement Governance

The Ontario Energy Board ("OEB" or the "Board") assesses Hydro One's transmission and distribution rate applications using a performance and outcomes-based approach, as established in the Board's Renewed Regulatory Framework (RRF). The RRF outlines four performance outcomes (customer focus, operational effectiveness, public policy responsiveness, and financial performance) which articulate the OEB's goals to align the interests of customers and utilities. The outcomes are supported by key principles in the RRF which include the expectation for continuous improvement, robust integrated planning and asset management which paces and prioritizes investments, strong incentives to enhance utility performance, ongoing monitoring of performance against targets, and customer engagement to ensure utility plans are informed by customer expectations.

In rate applications, a utility is expected to integrate its business challenges and customer preferences to create a compelling business plan that directly links the proposals and investments from the rate application to the four performance outcomes. In reviewing utility rate applications, the Board will analyze a utility's past performance on the outcomes, placing greater emphasis on future performance to ensure the key principles of the RRF are considered.

Performance scorecards are used to capture the four outcomes and the key principles of the RRF and are one of the mechanisms used by the Board in assessing the alignment of a utility's rate application to the RRF and the alignment of the interests of the utility to those of its customers.

This document describes how Hydro One tracks and reports its performance outcomes on its scorecards to align with the performance and outcomes-based approach of the Board in assessing utility rate applications and the key principles of the RRF.

In governing this process, Regulatory Affairs receives information and support from Hydro One's various operational lines of business and the Finance group, as further described below. The VP Planning has ultimate accountability for the Performance Reporting Governance Framework, working with various stakeholders to deliver on the requirements of the framework.

Performance Principles & Measures

The OEB requires Hydro One to report on its performance using a variety of measures contained in scorecards that are either developed or required by the OEB. For distribution rate applications, Hydro One uses the following scorecards: (i) the OEB's *Electricity Distributor Scorecard* (at Appendix A); and (ii) Hydro One's *Distribution OEB Scorecard* (at Appendix B). The Electricity Distributor Scorecard is produced by the OEB using the annual Reporting and Record-keeping Requirements (RRR) filings of Hydro One, Distribution. The Distribution OEB Scorecard was proposed by Hydro One in its 2018 to 2022 Distribution Rate Application (EB-2017-0049) to fulfill the requirements set forth in the Handbook for Utility Rate Applications[1], to propose measures in addition to those in the Electricity Distributor Scorecard. For transmission rate applications, Hydro One uses the following scorecard: (iii) Hydro One's

[1] Handbook for Utility Rate Applications, October 13, 2016, Ontario Energy Board

evolved Transmission Scorecard (at Appendix C). Together, the three scorecards are referred to as the "regulatory scorecards". At the overall corporate level, Hydro One uses (iv) the Team Scorecard and for Operations (v) the Operations Scorecard. The interactions between the various scorecards are shown below in Figure 1.

The regulatory scorecards are organized around the four RRF outcomes, and each outcome informs subsequent "performance categories" which are evaluated, for the most part, using quantitative measures that are tracked over a time and compared to targets that are specific to either the industry, Hydro One, or both. The regulatory scorecards are included at Appendices A through C and include the complete list of measures utilized to track and report performance improvements.

Planning for Performance Outcomes

To meet the targets in the regulatory scorecards, Hydro One incorporates the RRF principles and associated measures into its planning, execution, and reporting functions. RRF principles are integrated into Hydro One's corporate objectives and business plan and specific measures from each of the three regulatory scorecards are included in two of Hydro One's internal scorecards – the Team Scorecard and the Operational Scorecard. The Team Scorecard is included at Appendix D and the Operational Scorecard is included at Appendix E.

Figure 1 below shows how the RRF principles are incorporated into the performance reporting process for the regulatory scorecards and Hydro One's Team Scorecard and Operational Scorecard.

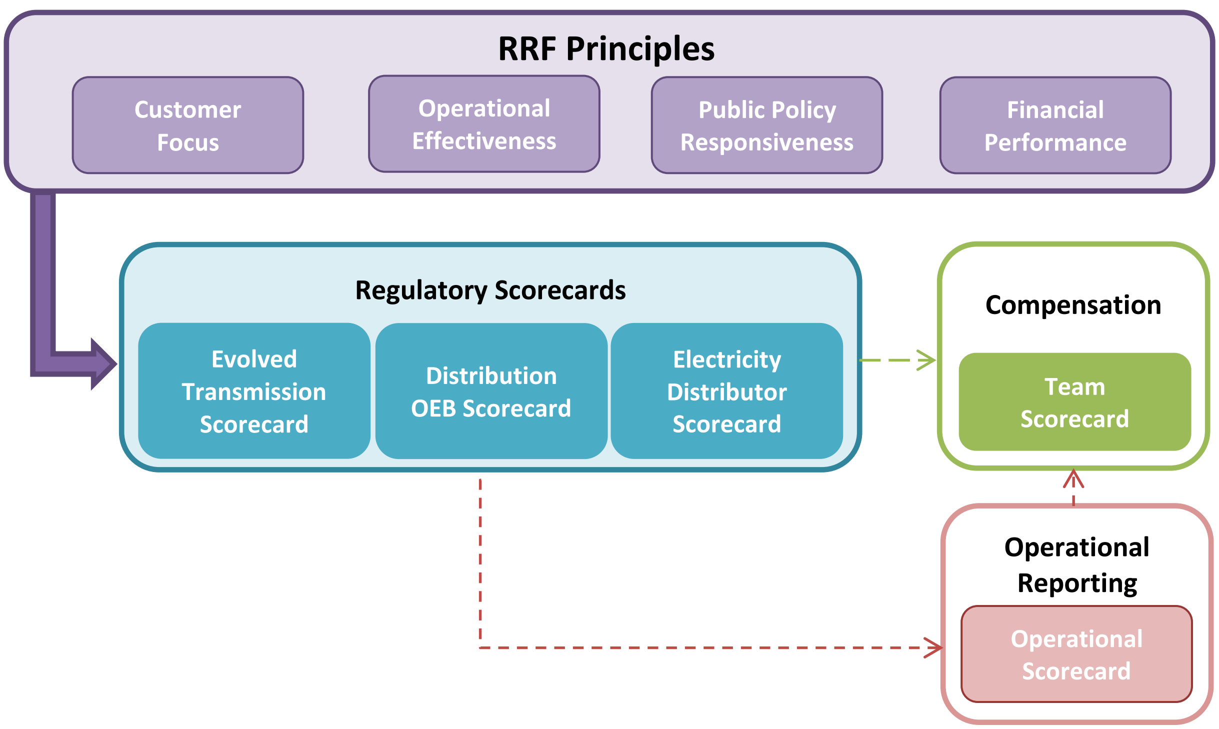

Figure 1 - Performance Reporting Scorecards & Interactions

Governance for Reporting & Development of Measures and Targets

Hydro One's governance framework is designed to support the key principles of the RRF of improvement, robust integrated planning and asset management, strong incentive to enhance performance, ongoing monitoring of performance against targets, and customer engagement to inform rate applications. The framework focuses on two primary activities of (i) performance reporting and (ii) measure and target development, which are supported by the governance matrices in Table 1 and

Table 2 respectively.

The primary stakeholders supporting the governance framework are:

- VP, Planning
- Line of Business Vice President (LoB VP)
- Line of Business (LoB)
- Finance
- Regulatory Affairs

The governance matrices define the roles and activities of each stakeholder using a responsible, accountable, consulted, and informed (RACI) framework, defined as:

- **Responsible** – for implementing or completing the identified activity or task. Responsibility can be shared amongst multiple stakeholders, with various degrees of responsibility;
- **Accountable** – for making decisions and taking actions on the activity or task. This stakeholder has ultimate decision-making authority and therefore, accountability cannot be shared;
- **Consulted** – with or communicated to prior to any final decisions being made or actions being taken. These stakeholders are typically subject matter experts and two-way communication is required;
- **Informed** – after decisions have been made or actions taken. These stakeholders may be required to act as a result of a decision being made or action being taken, however communication is typically one-way.

Table 1 - Governance Matrix for Performance Reporting

Activity	LoB	LoB VP	Finance	Regulatory Affairs	VP, Planning.
Provide executive sponsorship for performance measurement reporting, including by coordinating processes sponsored by LoB VPs	I	-	-	-	A
Sponsor performance reporting within the respective LoB	C	R	-	I	-
Execute performance targets and calculate results	R	A	I	I	I
Collect LoB performance results and produce regulatory scorecards for VP Planning/Executive Leadership Team (ELT) reporting	C	-	C	R/A	I
Integrate regulatory scorecard performance results into ELT reporting materials and report same to ELT	C	I	-	C	R/A
Update Team Scorecard on a regular basis for reporting	R	C/I	A	-	I
Monitor results and review Team Scorecard to ensure accuracy and alignment with approved methodology	C/I	C/I	R/A	-	I

R – Responsible; A – Accountable; C – Consulted; I – Informed

Table 2 - Governance Matrix for Performance Measure & Target Development

Activity	LoB	LoB VP	Finance	Regulatory Affairs	VP, Planning
Advise LoBs on regulatory requirements associated with the development of performance measures	I	C	C	R/A	C
Develop performance measures	R	A	C	C/I	C/I
Develop targets for the planning period	R	A	I	C/I	C/I
Review performance measures and targets to ensure alignment with OEB RRF, OEB Decisions, and regulatory requirements	C/I	C	C	R/A	C
Ensure each measure and target is defined, documented, measureable, reviewed, and approved by the LoB VP	R	I	I	R	A
Confirm measures and targets are included in the Business Plan	C	R	C	I	AI

R – Responsible; A – Accountable; C – Consulted; I – Informed

To support ongoing monitoring of performance against targets, scorecards are reported to the OEB, Hydro One's Executive Leadership Team, and Operations Managers as outlined in Table 3 below.

Table 3 - Scorecard Reporting Cadence & Deliverables

	Ontario Energy Board	Executive Leadership Team[2]	Operations Managers
Evolved Transmission Scorecard	As Required	Quarterly	Not Provided
Distribution OEB Scorecard	As Required	Quarterly	Not Provided
Electricity Distributor Scorecard	Annual, RRR	Quarterly	Not Provided
Team Scorecard	Upon Request	Monthly	Monthly
Operational Scorecard	Not Provided	Not Provided	Monthly

The Performance Reporting Governance Framework was designed and implemented by Hydro One to align with the Board's performance and outcomes-based approach to utility rate applications and in support of the key principles of the RRF to manage a network that is efficient, reliable, sustainable, and provides value for customers.

[2] For quarterly reporting, measures which are reported by external third-parties (e.g. PEG or ESA) or which cannot be reported in interim periods during the year (e.g. annual customer satisfaction) are omitted.

Appendix A - Electricity Distributor Scorecard – Example

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	2016	2017	Trend	Target	
										Industry	Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		97.40%	97.40%	97.50%	98.60%	98.06%	↑	90.00%	
		Scheduled Appointments Met On Time		98.40%	99.30%	98.50%	99.50%	98.94%	↑	90.00%	
		Telephone Calls Answered On Time		63.90%	69.60%	[illegible]	74.20%	81.85%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		78.30%	79%	82%	82	0.85			
		Billing Accuracy			94.63%	[illegible]	99.04%	99.28%	↑	98.00%	
		Customer Satisfaction Survey Results		87%	85%	[illegible]5%	84	0.85			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness				81.[illegible]	81.00%	81.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	NI	C	NI	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	7	[illegible]	5	11	8	↑		5
			Rate per 10, 100, 1000 km of line	[illegible]59	[illegible]	0.042	0.091	0.070	→		0.070
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		6.88	7.49	7.65	7.83	7.95	↓		10.31
		Average Number of Times that Power to a Customer is Interrupted [2]		2.49	2.70	2.63	2.47	2.32	↓		2.93
	Asset Management	Distribution System Plan Implementation [illegible]		Under Review	97%	116%	105	1.03			
	Cost Control	Efficiency Assessment		5	5	5	4				
		Total Cost per Custom[illegible]		$1,046	$1,069	$983	$987				
		Total Cost per Km of L[illegible] [3]		$10,682	$10,916	$10,198	$10,551				
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cu[illegible]lative Energy [illegible]				17.27%	42.50%				1,220.69 GWh
	Connection of Renewable Generation	[illegible]e Generation C[illegible]nection Impact Assessments Co[illegible] On Time		100.00%	100.00%	100.00%	100.00%	99.71%			
		New M[illegible]o-e[illegible]ded Generation Facilities Connected On Time		99.71%	100.00%	99.78%	99.22%	99.77%	↓	90.00%	
Financial Performance Financial viability is maintained and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.00	0.99	0.97	0.80	0.55			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.35	1.31	1.19	1.46	1.39			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.66%	9.66%	9.30%	9.19%	8.78%			
			Achieved	8.00%	6.26%	8.77%	8.41%	7.94%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing
reliability while downward indicates improving reliability.

Legend: 5-year trend: ↑ up, ↓ down, → flat
Current year: ● target met, ● target not met

Appendix B - Distribution OEB Scorecard – Example

RRFE Outcomes		Measure	Historical Results 2011	2012	2013	2014	2015	2016	201[illegible]	Targets [illegible]7	2018	2019	2020	2021	2022
Customer Focus	Customer Satisfaction	Customer Satisfaction - Perception Survey %	77%	78%	80%	67%	70%	66%	71%	72%	74%	75%	75%	76%	76%
		Handling of Unplanned Outages Satisfaction %	81%	79%	78%	75%	76%	75%	76%	76%	77%	78%	78%	79%	79%
		Call Centre Customer Satisfaction %	85%	84%	82%	[illegible]	85%	[illegible]%	90%	86%	87%	88%	88%	89%	89%
		My Account Customer Satisfaction %	81%	84%	64%	[illegible]5%	78%	[illegible]	78%	81%	83%	84%	84%	85%	85%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,541	8,441	7,824	[illegible]	8,392	8,350	8,431	8,640	8,733	8,908	9,080	9,256	9,437
		Vegetation Management - Gross Cyclical Cost per km $			New Progra[illegible]				7,888	New Program	3,600	3,643	3,687	2,400	2,428
		Station Refurbishments - Net Cost per MVA in $*	386,000	-	[illegible]18,000	348,[illegible]	500,000	557,000	443,000	461,000	454,000	447,000	440,000	434,000	427,000
		OM&A dollars per customer	456	451	[illegible]	551	453	455	430	449	466	466	466	454	455
		OM&A dollars per km of line**	4,723	[illegible]76	5,[illegible]	5,654	4,719	4,773	4,605	4,712	4,797	4,813	4,829	4,823	4,839
	System Reliability	Number of Line Equipment Caused Interruptions	7,681	7,3[illegible]	7,26[illegible]	8,311	8,164	7,674	8,786	8,200	8,200	TBD	TBD	TBD	TBD
		Number of Vegetation Caused Interruptions	6,113	[illegible]953	5,791	6,540	6,944	7,439	7,800	6,900	6,500	TBD	TBD	TBD	TBD
		Number of Substation Caused Interruptions	159	[illegible]	129	158	141	103	123	145	145	TBD	TBD	TBD	TBD
		SAIDI - Rural - duration in hours	8.2	8.2	8.1	8.6	9.1	9.1	9.4	9.1	9.0	TBD	TBD	TBD	TBD
		SAIFI - Rural - frequency of outages	[illegible]	3.3	3.0	3.4	3.4	3.1	3.0	3.4	3.4	TBD	TBD	TBD	TBD
		SAIDI - Urban - duration in hours	2.7	3.2	2.2	2.8	2.8	2.4	2.4	2.8	2.8	TBD	TBD	TBD	TBD
		SAIFI - Urban - frequency of outages	1.6	1.7	1.6	2.3	1.4	1.6	1.4	1.7	1.7	TBD	TBD	TBD	TBD
		Large Customer Interruption Frequency (LDAs) [illegible]ency of outages***	New Measure		118	147	228	136	227			N/A***			
		Large Customer Interrupti[illegible]equency (LDAs) - [illegible]te[illegible]ns per LDA			New Measure				1.7	New Measure	1.6	1.6	1.6	1.6	1.6

*There were no station refurbishment units matching t[illegible]iteria completed in 2[illegible].

**Number of line kms are based on the annual OEB Year[illegible]k of [illegible]ctricity Distrib[illegible]ors' report, with 2017 and 2018 targets based on 2015 line km actuals. Targets for 2019 to 2022 are based on the RRR km of line for year-end 2017.

***Replaced by Large Customer Interruption Frequency (L[illegible] - Interruptions per LDA. For 2018 onwards, only the normalized measure will be reported and managed.

Appendix C - Evolved Transmission Scorecard – Example

Performance Categories	Measures	2013	2014	2015	2016	2017	Target for 2022	Target for 2023
Customer Satisfaction	Satisfaction with Outage Planning Procedures (% Satisfied)		86	92	89	94	87	88
	Overall Customer Satisfaction (% Satisfied)	81	77	85	78	88	90	90
Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	12.8	11.8	14.3	9.7	9.5	11.3	11.0
Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)	2.5	1.8	1.7	1.1	1.2	0.9	0.9
System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)	0.57	[illegible]	0.59	0.46	0.65	0.52	0.51
	T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)	0.69	[illegible]	0.50	0.33	0.47	0.47	0.46
	T-SAIDI (Ave minutes of interruptions per Deliver Point)	[illegible]	36.6	[illegible]	80.8	42.8	33.3	32.6
	System Unavailability (%)	[illegible]	0.48	0.63	0.71	0.68	0.46	0.45
	Unsupplied energy (minutes)	20.9	12.2	11.8	11.4	13.2	9.2	9.0
Asset & Project Management	Transmission System Plan Implementation Progress (%)	94	99	105	100	94	100	100
	CapEx as % of Budget	73	90	106	105	100	100	100
	OM&A Program Accomplishment (composite index)			96.6	99.2	107.7	100.0	100.0
	Capital Program Accomplishment (composite index)			122.2	59.4	87.8	100.0	100.0
Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	7.6	8.4	9.0	8.6	7.9	7.7	7.3
	OM&A per Gross Fixed Asset Value (%)	2.7	2.7	2.9	2.5	2.3	1.6	1.5
	Line Clearing Cost per Kilometer ($/km)	1,805	2,495	2,234	1,966	2,100	2,175	2,100
	Brush Control Cost per Hectare ($/Ha)	1,703	1,624	1,566	1,542	1,356	1,608	1,608
Connection of Renewable Generation	% on-time completion of renewables customer impact assessments	100	100	100	100	100	100	100
Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning progress - Deliverables met, %		100	100	100	100	100	100
	End-of-Life Right-Sizing Assessment Expectation					Met	Met	Met
Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.80	0.69	0.13	0.20	0.13		
	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.10	1.16	1.39	1.43	1.47		
	Profitability: Regulatory Return on Equity – Deemed (included in rates)	8.93	9.36	9.30	9.19	8.78		
	Profitability: Regulatory Return on Equity – Achieved	13.22	13.12	10.93	10.02	9.03		

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Appendix D - Team Scorecard – Example

Corporate Goal	Definition	Measure	2017 Performance Levels				% Weight	Achievement	% STIP
			Actual	Threshold	Budget	Maximum			
Health and Safety (10%)	Recordable Incidents	Incidents per 200,000 hours	1.2	1.6	1.1	1.0	10.0%		
Work Program (25%)	Reliability – Tx (SAIDI)average length of unplanned interruptions to multi-circuit supplied delivery points	Minutes per Delivery Point	5.4	10.0	9.6	[illegible].2	6.3%		
	Reliability - Dx (SAIDI) average length of outages in hours that a customer experiences	Hours per Customer	7.9	7[illegible]	7.5	7.2	6.3%		
	Tx In Service Additions Delivery Accuracy	Variance (%) to approved budget of $931M (Tx Application)	87[illegible]	+/- [illegible]% (978-9[illegible]; 866-884)	+/- 5% (950-978; 884-912)	+/- 2% (912-950)	6.3%		
	Dx In Service Additions Delivery Accuracy	Variance (%) to approved budget of $663M	681	+/- 6% (690-703; 623-636)	+/- 4% (676-690; 636-650)	+/- 2% (650-676)	6.3%		
Net Income (30%)	Net Income to Common Shareholders	$M	694***	615	665	715	30.0%		
Productivity (10%)	Productivity Savings (Capital and OM&A) - Tier 1 savings only	Savings in $M	89.5	64.3	70.6	77.7	10.0%		
Customer (25%)	Dx Satisfaction - Improve overall Small and Residential Dx customer satisfaction	Customer Satisfaction	71.1%	70.0%	72.0%	75.0%	12.5%		
	Tx Satisfaction - Improve overall Large Tx customer satisfaction	Customer Satisfaction	88.3%	80.0%	82.0%	85.0%	12.5%		

Appendix E - Hydro One's Operational Scorecard – Example

Objective	Metric	Measure
Safety	Recordable Incidents	*Overall incidents per 200k hrs – Ops*
	Serious Incidents	*High MRPH per 200k hrs – Ops*
	Preventable Motor Vehicle Accidents	*# preventable accidents per 200k hrs*
Reliability	Transmission Reliability	*Tx SAIDI, multi-circuit network (mins)*
		Tx SAIFI, multi-circuit network (# interruptions)
	Distribution Reliability	*Dx SAIDI (hrs)*
		Dx SAIFI (# interruptions)
Work Program	In-Service Capital	*Tx Ops In-Service Capital ($M)*
		Dx Ops In-Service Capital ($M)
		% Capital units complete (spend weighted)
	OM&A	*Tx Ops OM&A ($M)*
		Dx Ops OM&A ($M)
		% OM&A units complete (spend weighted)
Productivity	Productivity Savings	*Productivity savings ($M)*
Customer	Tx customer experience	*Tx customer commitments met (%)*
	Dx customer experience	*New residential/small business customers connected on time (%)*
		Scheduled appointments met on time (%)
Other	Compliance	*NERC & NPCC standards compliance (# non-compliances)*
	Engagement	*Gallup engagement survey Grand Mean - Ops*

Appendix 5-A
Metrics

Metric Category	Metric	Measures	
		1 Year	5 Year Average
Cost	Total Cost per Deliver Points1	2,075,508	1,946,674
	Total Cost per km of Line[2]	50,388	46,908
	Total Cost per MW[3]	59,657	56,374
CAPEX	Total CAPEX per Delivery Points	1,448,004	1,337,183
	Total CAPEX per km of Line	35,154	32,231
O&M	Total O&M per Delivery Points	627,504	609,491
	Total O&M per km of Line	15,234	14,677

Notes to the Table:

1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of Deliver Points that the distributor
2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that the distributor
3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves.

Explanatory Notes on Adverse Deviations (complete only if applicable)

Metric Name:

Hydro One is using the number of Delivery Points as proxy for the number of Customers.

Metric Name:

Hydro One is using the number of Delivery Points as proxy for the number of Customers.

Metric Name:

Hydro One is using the number of Delivery Points as proxy for the number of Customers.

1.6 (5.2.3) PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT: PRODUCTIVITY

To further its commitment to delivering outcomes that are valued by its customers, Hydro One has developed a comprehensive and rigorous process for identifying, developing, implementing, monitoring and measuring productivity initiatives that will reduce costs while maintaining or improving service quality and work outputs. Hydro One's commitment to achieving incremental and continuous productivity improvements is central to the planning and execution of work programs across the company. Within this framework, quantifiable productivity improvements are included in the Business Plan and corporate scorecards with clear accountabilities for delivering the anticipated savings. Using this approach, as described below, Hydro One has identified savings opportunities in Capital and OM&A totalling approximately $704M over the 2020-2024 TSP period.

This section describes Hydro One's productivity framework and its clearly defined process for achieving demonstrable productivity improvements, followed by a summary of the specific productivity savings that are accounted for and built into its proposed OM&A and capital expenditure plan.

1.6.1 PRODUCTIVITY FRAMEWORK

Hydro One's productivity framework is comprised of internal governance around the classification of productivity savings and the process for identifying and obtaining internal approval for productivity initiatives, which must meet certain criteria for acceptance, along with the corresponding accountabilities for approving initiatives, achieving savings, tracking and reporting on productivity performance, and integrating planned savings into business planning.

1.6.1.1 (5.2.3 A) PRODUCTIVITY GOVERNANCE

Hydro One's Finance group has designed a process (described below in sections 1.6.1.2 and 1.6.1.3) to support continuous improvement in the company's efforts to identify, implement, measure and report on productivity across all lines of business. The process is managed and maintained by the Finance group, which oversees the effective, consistent and disciplined implementation of this process so as to ensure that productivity changes are accurately measured and reported on Hydro One's scorecards, and that anticipated productivity improvements are consistently identified in the company's Business Plan. In addition to the oversight and management roles played by Finance, staff from each of the affected lines of business play an integral role in the Hydro One's productivity process and framework. Reporting of productivity results are provided on a monthly basis to senior executives within each line of business, as well as to the CEO.

To ensure continuity in the planning process, rate filing applications, and tracking methodology, Hydro One's productivity initiatives are considered using 2015 as the baseline year for evaluating savings of legacy initiatives. Most legacy initiatives were identified as part of Hydro One's 'Good to Great' initiative. Newly identified incremental initiatives use the last approved plan period as the baseline year. When describing the productivity savings that are incorporated into Hydro One's capital expenditure plan, only the productivity savings anticipated over the TSP plan period are referenced.

1.6.1.2 (5.2.3 A) TIERED PRODUCTIVITY REPORTING

Hydro One introduced a tiered reporting structure so as to clearly differentiate between productivity improvements that will result in actual cost savings ("Tier 1 Productivity") and those that will enable Hydro One to complete more work for the same cost ("Tier 2 Productivity"). Only those savings that contribute to overall direct cost reductions in the Business Plan relative to their baseline, i.e. Tier 1 Productivity savings, are reported against productivity targets in Hydro One's corporate scorecards. However, all savings are monitored and tracked. For greater certainty, Hydro One defines the tiers as follows:

> "Tier 1 Productivity" means net savings with a direct correlation to a budget and/or spending forecast reduction (i.e. 'hard savings'), which are monitored, tracked and reported on corporate scorecards.

> "Tier 2 Productivity" means all unit based savings, other than Tier 1 Productivity savings, which are derived from calculation methodologies approved by Finance and result in Hydro One getting incremental work completed or increased output for the same dollars input (i.e. 'more work'), which are not reported on corporate scorecards but which are otherwise monitored and tracked.

1.6.1.3 (5.2.3 A) METHODOLOGY AND REVIEW PROCESS

Hydro One's productivity process was executed in parallel with, and as an input to, its business planning process. Through the productivity process and framework, each of Hydro One's lines of business[1] was asked to identify productivity initiatives that would have the potential to result in savings. In consultation with the Finance group, the lines of

[1] Hydro One's lines of business with productivity commitments are Fleet Services, Supply Chain, Station Services, Network Operating, Distribution Lines, Forestry Services, Information Technology, Corporate Groups, Planning, Customer Service, and Engineering**.**

business were required to demonstrate that each proposed productivity initiative would be capable of achieving demonstrable unit based savings, that each initiative had a corresponding auditable measurement methodology, and that each initiative was considered in the development of the Business Plan and associated investments. Finance worked with initiative owners to validate planning assumptions and spending reductions to ensure that the expected savings were appropriately embedded in the Business Plan wherever possible, and that expected savings would be passed on to ratepayers. The embedded savings resulted in actual plan reductions which would otherwise not have been attainable.

In the early stages of the process, each of the lines of business submitted their proposed productivity initiatives to Hydro One's Finance group for review. Finance reviewed each submission for completeness and to ensure that the measurement methodology was unit based and auditable. If Finance approved the initiative and confirmed that it would have the effect of reducing a department or program budget, then the initiative was deemed to qualify for tracking and reporting against the company's Tier 1 Productivity target up to the forecast amount of the spending reduction, with further savings to be tracked as Tier 2 Productivity savings. Collectively, the approved and validated initiatives included in the Business Plan comprise Hydro One's productivity plan.

Productivity achievements are reported on a monthly basis. As noted above, all productivity initiatives must be approved by Finance before any actual savings can be reported against savings targets or on corporate scorecards. This approval process ensures that each productivity initiative is carefully tracked using a detailed and robust calculation methodology so as to ensure savings are verifiable and auditable.

For purposes of reporting, Finance reviews all productivity initiatives to ensure they are:

- Consistently and thoroughly documented (including detailed description/logic, identified systems/dependencies, clear calculation methodology/data source and reasonable exclusions/adjustments);
- Auditable (with an applicable baseline for reporting);
- In-line with Hydro One's definitions and classifications of productivity (i.e. Tier 1/Tier 2); and
- Reviewed and approved by a VP or delegate.

Similar processes are followed and approvals required for any new productivity initiatives or forecast changes to existing productivity initiatives that are identified by lines of business.

The lines of business are accountable for achieving the productivity savings through their approved initiatives, as well as for regularly providing budget and forecast trends and actuals on a monthly basis, which are verified by Finance for reporting purposes. Finance maintains and tracks performance for all initiatives and manages the governance documents relating to the productivity process and framework.

Reported productivity savings are tracked and monitored by Hydro One on a continuous basis to ensure business outcomes are achieved. All planned Tier 1 Productivity savings in the 2020-2024 TSP period have been validated as being considered in the creation of the Business Plan. These expected savings are discussed in section 1.6.2.2 below.

1.6.2 (5.2.3 D) PRODUCTIVITY SAVINGS IN THE PLAN

The following describes the OEB's directions to Hydro One from its last transmission rates proceeding, followed by an overview of the specific productivity savings that have been included in Hydro One's plans.

1.6.2.1 OEB DIRECTION FOR PRODUCTIVITY IMPROVEMENTS IN EB-2016-0160

In the OEB's Decision in EB-2016-0160, it directed Hydro One to establish firm short-term and long-term targets for productivity improvements and associated reduction in revenue requirement as a means to drive continuous improvement and improve the company's internal and external benchmarking standings. Hydro One has identified savings opportunities in Capital and OM&A totalling approximately $704M over the 2020-2024 TSP period. These savings have been embedded into the Business Plan and this TSP. The savings targets are measured and tracked continuously, and reported on a monthly basis to Hydro One's Executive Leadership Team to ensure that Hydro One is meeting its planned deliverables at a lower unit cost without a reduction in planned work volumes. Developing initiatives and processes that drive Hydro One to continuously become more productive and more efficient over time are cornerstones of Hydro One's plan.

1.6.2.2 OVERVIEW OF PRODUCTIVITY SAVINGS

The savings driven by Hydro One's internally approved productivity initiatives have been included in the detailed OM&A and Capital expenditure plans. A summary of Hydro One's forecast productivity savings for the 2020-2024 TSP period is provided in Table 1.

Table 1 - Productivity Savings Forecast Summary ($Millions)

$mm	2020	2021	2022	2023	2024	Total
Operations	47	52	53	53	54	259
Progressive Operations (Defined Capital)	6	12	12	10	10	49
Corporate	12	11	9	7	6	45
Capital Total	**$65**	**$74**	**$73**	**$70**	**$70**	**$353**
Operations	9	10	9	9	9	45
Information Technology	6	9	10	10	10	44
Corporate	7	6	5	4	3	25
OM&A Total	**$22**	**$25**	**$23**	**$23**	**$22**	**$114**
Total Defined	**$87**	**$99**	**$97**	**$93**	**$92**	**$468**
Progressive Operations (Undefined Capital)	11	27	49	68	81	237
Grand Total	**$98**	**$126**	**$146**	**$161**	**$173**	**$704**
Progressive Productivity						
Progressive Operations (Defined Capital)	6	12	12	10	10	49
Progressive Operations (Undefined Capital)	11	27	49	68	81	237
Progressive Productivity Placeholder	17	39	61	78	91	286

As noted in the table above, Hydro One has identified savings opportunities totalling approximately $704M over the 2020-2024 TSP period. This reflects Tier 1 Productivity savings only. There are $353M in capital productivity savings, $114M in OM&A productivity savings and $237M in undefined capital savings. This latter category of savings falls within “Progressive Productivity”. Progressive Productivity is a further reduction in cost that Hydro One has included in the final Transmission Business Plan in response to concerns that were raised in the OEB’s decision in the Prior Proceeding regarding the level of investment. It represents a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned investments in its transmission system without reducing work volumes. Progressive Productivity savings total $286 million over the planning period and are included in the Transmission Business Plan in the form of:

1. $49 million in Progressive Operations (Defined Capital) savings associated with initiatives that have been identified but which have not yet been proven and verified through the productivity governance framework; and
2. $237 million in Progressive Operations (Undefined Capital) savings which are included as placeholder in the Business Plan to be allocated to any future initiatives that have not yet been identified.

Approximately $590M of the identified savings opportunities are related to Operations (Operations OM&A, Operations Capital, Progressive Operations (Defined Capital) and Progressive Operations (Undefined Capital), approximately $44M in savings are IT-related (OM&A and Capital) and $70M in savings are related to Corporate Initiatives (OM&A and Capital).

Underlying the savings in Hydro One’s productivity plan are specific productivity initiatives that have been identified, reviewed, approved and made subject to tracking and reporting requirements in accordance with the productivity framework and process described in Section 1.6.1, above. The savings arising from each of these initiatives are real reductions from department or program budgets. Additional Tier 2 Productivity savings may be achieved in connection with these and other initiatives, but such additional savings cannot be forecasted and are not accounted for in the planned savings.

By embedding all of the forecast productivity savings - from specific productivity initiatives and progressive productivity (discussed below under progressive productivity section) - into Hydro One’s Business Plan, Hydro One bears the risk of not delivering its planned productivity improvements. This creates a strong incentive for Hydro One to follow through on its productivity commitments.

Operations

In Table 1 above, $590M of savings (Capital, OM&A and Progressive) are related to Operations. These savings are comprised of:

- $304M of savings that have been identified through specific underlying Operations productivity initiatives (OM&A and Capital) including Procurement, Fleet Services, Station Maintenance and Network Operating.
- $286M of savings that will be achieved through the application of Progressive Productivity over the 2020-2024 TSP period on the transmission work program. Progressive productivity initiatives have not been planned at a specific project or program level but have been applied to the business plan as a negative 'Progressive Productivity Placeholder' in the capital work program. Hydro One will continue to define and validate initiatives until all of the undefined progressive savings targets ($237M) are allocated to specific work programs and projects as discrete initiatives. Upon validating the defined initiative, the Progressive Productivity Placeholder will be eliminated and the affected cost driver will be reduced.

Together, these savings demonstrate Hydro One's commitment to identifying and implementing efficiencies and minimizing operations expenses before passing such costs on to customers. Operations savings will be realized by committing to the implementation of productivity initiatives that leverage new technology and processes, and in some cases drive significant change to the way that Hydro One plans and completes work. The basis for Hydro One's identified savings in each of these areas is discussed below.

Procurement

Hydro One's Supply Chain division has made several changes to its sourcing processes to increase productivity and reduce expenses. Of the expected $590M in total Operations savings (OM&A and Capital including progressive productivity), Hydro One forecasts that $190M in savings over the 2020-2024 TSP period will result from procurement enhancements. Enhancements such as, but not limited to the following, are enabling these significant procurement savings:

- **Bundling/Volume Discounts –** Hydro One will undertake a comprehensive review of its sourcing categorization by grouping materials/services supplied by like-suppliers to maximize savings and take better advantage of volume discount opportunities by addressing multiple sub-categories at once. Through this approach, Hydro One will seek to bundle multiple contracts with a single supplier and negotiate volume discounts across multiple categories and contracts.
- **Feedback Rounds –** Hydro One will seek to maximize competitive pressure by implementing multiple feedback rounds on rates so as to provide an opportunity for potential vendors to improve their proposals.
- **'Lean' RFPs –** Hydro One will emphasize leaner, "bidder-friendly" scope and value in RFP formats with fewer and less onerous requirements.
- **Standardization of Specifications –** Hydro One will standardize requirements to allow for direct, like-for-like comparisons across bidders. It will also employ industry-standard specifications where appropriate, rather than Hydro One specifications, to reduce unnecessary costs.
- **Streamlined Evaluation –** Hydro One will seek to compress timelines and streamline evaluation processes to meet business needs and accelerate the realization of negotiated savings.
- **Cost Transparency –** Hydro One will enhance its understanding of bidder pricing elements to improve its ability to challenge and negotiate more competitive pricing.

Fleet Services

Hydro One forecasts, and has embedded in the Business Plan, over $56M in fleet savings over the 2020-2024 TSP period as a result of the implementation and use of telematics. Telematics integrates telecommunications systems, including global positioning systems

(GPS) and informatics systems that provide vehicle locations and live vehicle operation and performance data. The telematics project was successfully rolled out to all fleet vehicles and equipment at the end of 2016 and provides analytics that will allow Hydro One to realize productivity efficiencies for the 2020-2024 TSP period. In 2017, Fleet Services started to leverage telematics data to define baseline metrics with respect to equipment utilization, non-productive idling and fuel efficiency. The accumulated data has enabled Fleet Services to accelerate the rationalization of the fleet and reduce the need to purchase additional equipment without compromising service quality to operating divisions.

Stations Services and Network Operating Groups

Hydro One forecasts, and has embedded in the Business Plan, over $37M in savings over the 2020-2024 TSP period as a result of the implementation of various initiatives for the Station Services and Network Operating groups, including:

- Overtime Reduction Strategies - Hydro One is focusing on reducing overtime spending by tightening controls and implementing more stringent approval methods. High priority corrective maintenance can account for a large portion of overtime spend.
- Improved Scheduling - Maintenance plans are being reviewed in a more stringent manner between lines of business to ensure that the right work is being released for the right equipment to be completed in the most optimal conditions and on a more consistent basis. Improved technology and software has also resulted in cost savings relating to scheduling staff.
- Ongoing Wrench Time Studies - A detailed analysis of specific work tasks performed on the same equipment across all zones is being performed to determine the best and worst cost ratios and establish a median standard for internal benchmarking. The identified best practices used by the most efficient crews will be implemented across all zones to increase overall efficiency.

Progressive Productivity

Progressive Productivity is a further reduction in cost that was applied to Hydro One's final transmission investment plan as a 'Progressive Productivity Placeholder' in response to the concerns that were raised by the OEB regarding the pacing of investments in Hydro One's 2017/2018 Transmission Rate Decision (EB-2016-0160).

During the planning process, after the Decision in EB-2016-0160 was received, project planners worked with management to reduce the total capital plan and associated rate impacts. While reviewing the system requirements and planned work, it was ultimately determined that rather than reducing specific programs and projects further, Hydro One would commit to finding additional efficiencies during the 5 year plan which would allow the completion of the necessary work while also benefiting customers with reduced rate impacts. With the exact source of these efficiencies unknown, the savings were estimated on the overall work program; committing the company to delivering the same work program volume for 1%-3% less on a year over year basis. These savings will be sought in common project-specific areas such as:

- better utilization of tools;
- improved processes to reduce labour waste/churn;
- optimization of commissioning work; and
- additional project initiatives designed to meet the productivity commitments that will be identified as projects progress through their estimation and execution life cycle.

The identification and inclusion of these savings in this application represent a significant incremental commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned investments without reducing work volumes. Hydro One has given the benefit of these savings to ratepayers up front and has taken on the execution risk to deliver its planned work program within a reduced funding envelope. As initiatives are defined, they will be reviewed in line with Hydro One's productivity governance framework and, if approved, the savings will be tracked and credited as an achievement by the project against the savings target.

Information Technology

Overall, Information Technology savings over the plan period is primarily driven by the renegotiation of the outsourced Inergi agreement. The new agreement results in rationalized IT spending and considerable contractor rate reductions. IT savings totalling over $44M (OM&A and Capital) over the 2020-2024 TSP period have been embedded into the transmission business plan.

Corporate Costs

In conjunction with enhancing value for customers and all stakeholders of the Company, a thorough review of corporate based costs was completed during the latter portion of 2018 which resulted in identified and embedded savings of approximately $70 million (OM&A and Capital) over the 2020-2024 TSP period. The reductions were achieved primarily through a reduction in vacancies and limiting consulting and contracts to critical functions, with an overall focus on building internal capabilities.

1.7 (2.4) LONG-TERM ENERGY PLAN

The Minister of Energy is required by Section 25.29 of the *Electricity Act, 1998* to periodically issue a Long-Term Energy Plan ("LTEP") to set out the Government of Ontario's goals and objectives regarding energy plans. The goals and objectives described in the LTEP address the issues of cost effectiveness and reliability of the province's transmission system, as well as distribution systems, and thereby have a direct impact on Hydro One's transmission capital plans.

The following Sections provide: (a) an overview of the evolution of the long-term energy plan and its context; (b) a summary of the relevant aspects of the 2017 LTEP; and (c) a discussion of the impact of the 2017 LTEP on Hydro One's transmission capital plans.

1.7.1 THE LONG-TERM ENERGY PLAN EVOLUTION

The LTEP has evolved over the last nine years since it was introduced. The initial 2010 plan, entitled "Ontario's Long-Term Energy Plan, Building Our Clean Energy Future"[1], focused on a number of key areas:

- Supply (including retirement of coal fired generation and the development of renewable generation);
- Demand management and energy conservation;
- Development of priority transmission facilities (including five transmission projects to facilitate reliability and renewable energy growth);
- First Nations engagement; and
- Electricity prices.

[1] https://www.ontario.ca/document/2010-long-term-energy-plan

In 2013, the second LTEP was released by the Ministry of Energy entitled 'Ontario's Long Term Energy Plan, Achieving Balance'[2]. This 2013 LTEP continued to build on the principles laid out in the 2010 LTEP and was designed to balance the following five principles: cost-effectiveness, reliability, clean energy, community engagement, and an emphasis on conservation and demand management before building new generation. Special attention was also given to transmission development in the Northwest and joint project development with First Nations.

In 2016, the Government of Ontario modified the *Electricity Act, 1998* to formalize the LTEP process. These legislative changes include a requirement for consultation with local communities, stakeholders and other ministries, along with engagement with First Nation and Métis communities. The legislative changes also required a technical report to be developed by the Independent Electricity System Operator ("IESO") on the adequacy and reliability of electricity resources with respect to anticipated electricity supply, capacity, storage, reliability, and demand.

In addition to these legislative changes, Ontario's energy use has changed substantially in the last decade. Ontario homes, businesses and industries are becoming more efficient, while at the same time new technology and renewable energy sources are being explored. To guide Ontario in adapting to these changes, a third LTEP was issued on October 26, 2017 by the Minister of Energy, entitled "Delivering Fairness and Choice"[3].

[2] https://www.ontario.ca/document/2013-long-term-energy-plan
[3] https://www.ontario.ca/document/2017-long-term-energy-plan

1.7.2 OVERVIEW OF THE 2017 LTEP

The 2017 LTEP purports to set the course for Ontario's energy supply over the coming years by building on the work of the past years. It maintains the key priorities established in previous plans and includes a number of new initiatives to further these objectives.

The 2017 LTEP's primary goals are to keep electricity prices affordable, cut costs where possible, facilitate market renewal, limit new supply procurements, support renewable generation, support supply to remote First Nations communities, put conservation first, and stimulate innovation. The main features that affect the electricity sector are as follows:

- **Affordability:** Electricity prices for large customers are expected to be in line with inflation over the forecast period. The costs of existing investments will be spread over a longer period of time.

- **Flexible Energy Supply:** Movement away from long term electricity contracts to a more market based competitive approach where the most cost effective resources would be utilized to provide supply under the IESO's market renewal process.

- **Innovation:** Work on incorporating innovation across the entire energy supply chain through initiatives to: provide customers more choice in their electricity price plans, enhance the net metering framework to allow customers to incorporate clean renewable generation, facilitate grid modernization including distributed energy resources and electric vehicle grid integration, reduce barriers to energy storage, evaluate use of electricity to create hydrogen, and collaborate with the federal government, universities, and industry to support the nuclear sector.

- **Value and Performance to Customers:** Renew consumer-focus by improving efficiency and reliability, making utilities more accountable to their customers, promoting cost reductions, and improving and streamlining regulatory process and reliability standards. The focus will also be on developing a process for competitive procurement for transmission and promoting the right sizing of transmission and distribution assets at end-of-life.

- **Energy Conservation and Efficiency:** Reaffirm the provincial government's commitment to conservation and a clean electricity system which includes renewable generation that supports the Climate Change Action Plan[4]. Also, promoting opportunities to access renewable generation and energy storage technologies by expanding net-metering options.

- **Support First Nation Capacity and Leadership:** Prioritize the connection of remote First Nation communities to the grid and provide support for the four First Nation communities for which transmission connection is not economically feasible. Also explore options to integrate small scale renewable energy projects, net metering or other solutions to address local or regional energy needs.

- **Support Regional Solutions and Infrastructure:** Continue to implement conservation policies in regional and local energy planning processes; looking at ways to improve the existing regional planning process and reduce barriers to the use of conservation, demand response or other distributed energy resources.

The Minister of Energy directed the OEB[5] and the IESO[6] to develop implementation plans by January 31, 2018 to meet these LTEP goals.

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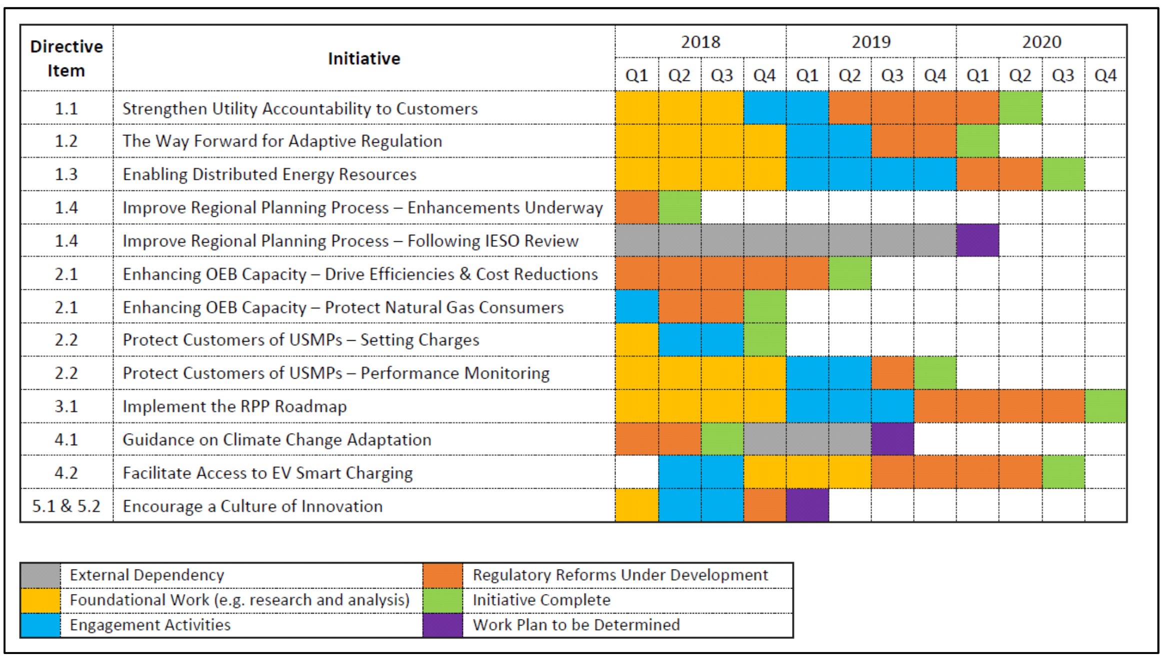
[4] https://www.ontario.ca/page/climate-change-action-plan
[5] https://www.oeb.ca/sites/default/files/Directive_to_OEB_LTEP_Implementation_Plan_20171026.pdf
[6] http://www.ieso.ca/corporate-ieso/ministerial-directives *(Directive dated: October 26, 2017)*

On February 15, 2018 the Minister of Energy approved both the OEB's Implementation Plan[7] and the IESO's Implementation Plan[8] that set forth their action plans to meet the LTEP goals.

The OEB implementation plan initiatives and their timings are given in Figure 1 below. Most of the initiatives will primarily impact the distribution system. The impact on the transmission system will be due to potential change in load forecasting on the distribution system as a result of these initiatives. Initiative 1.4 is aimed at enhancing and improving the Regional Planning Process and is expected to improve the determination of the need and timing for new facilities.

Figure 1: OEB Implementation Plans



Extract from page 40 of the OEB Implementation Plan

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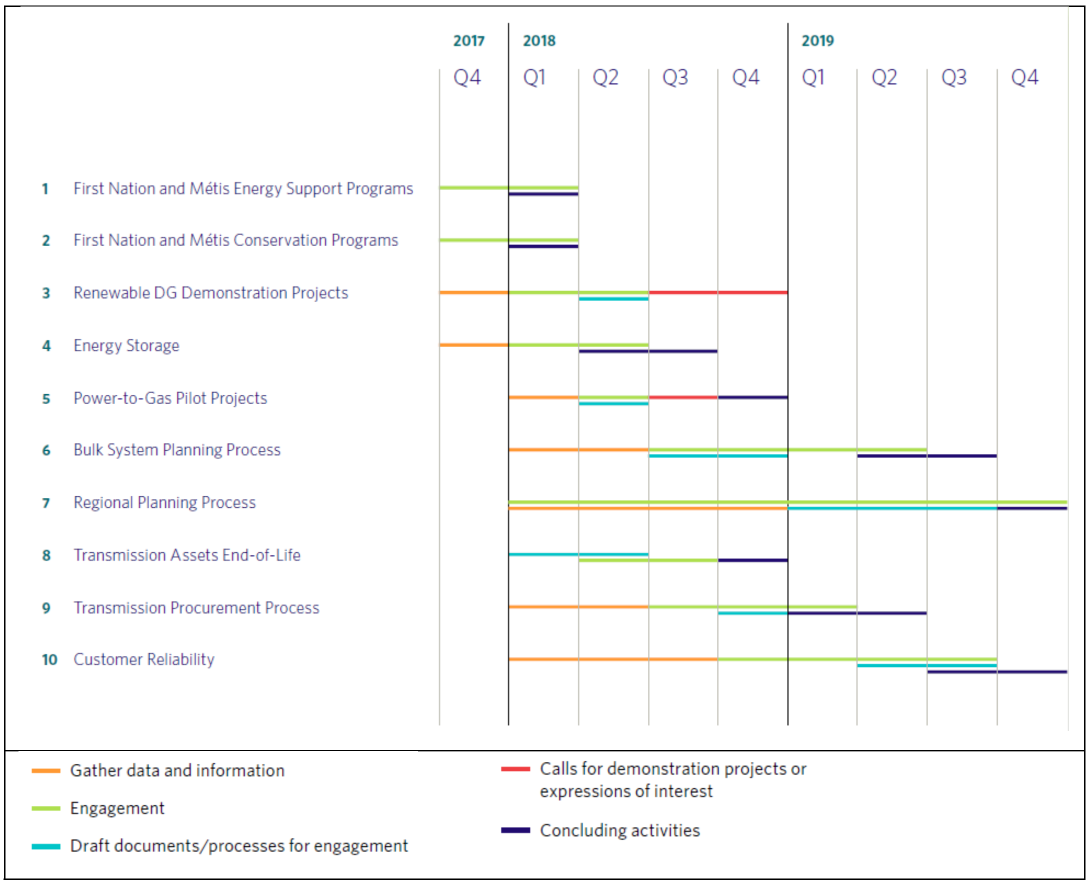
[7] https://www.oeb.ca/sites/default/files/OEB-LTEP-Implementation-Plan.pdf
[8] http://www.ieso.ca/-/media/Files/IESO/Document-Library/ltep/IESO-ltep-implementation-plan.pdf

The IESO implementation plan initiatives and their timings are given in Figure 2 below. Initiatives 6 to 10 impact transmission. Of these, Initiatives 6, 7 and 8 are aimed at improving the planning processes for determining the need and timing of the facilities; Initiative 9 will consider the development of competitive transmission; and Initiative 10 covers a review of the existing Ontario transmission reliability criteria.

Figure 2: IESO Implementation Plan



Extract from page 26 of the IESO Implementation Plan "Putting Ontario's Long-Term Energy Plan into Action"

1.7.3 IMPACT OF THE 2017 LTEP ON THE TRANSMISSION CAPITAL PLAN

The 2017 LTEP indicates that the IESO's forecasts for electricity demand[9] remain relatively flat until 2035 and, therefore, no major expansion of the provincial transmission system is required beyond those projects that are already planned or under development.

The transmission system initiatives referred to in the LTEP that form part of Hydro One's 2020 to 2024 capital plans, are summarized in Table 1 below. One of these transmission system initiatives (Project 6) was completed in 2018; however the project has been included in the table for completeness.

Table 1: 2017 LTEP Major Transmission Projects

No	Project Description	Need and Details	In-Service Date
1	Northwest Bulk Transmission Line	Support growth and maintain a reliable supply to areas west of Atikokan. Further details are presented in TSP Section 3.3.8 ISD SS-08.	(Phase 1) mid-2030s*
2	East – West Tie Transmission Line	Improve supply reliability to meet demand and changes in supply mix in Northwest Ontario. Further details are presented in TSP Section 3.3.8 ISD SS-04.	2022
3	Greater Toronto Area West Bulk Reinforcement	Improve supply capability in the western section of the Greater Toronto Area. Further details are presented in TSP Section 3.3.8 ISD SS-07.	2025
4	Hawthorne to Merivale	Optimize use of the interties with Quebec and increase capability to serve load in western Ottawa. Further details are presented in TSP Section 3.3.8 ISD SS-06.	2022
5	Lake Erie Connector	Facilitate interconnection between Ontario and markets in US. Further details are presented in TSP Section 3.3.8 ISD SS-03.	2022
6	Clarington Transformer Station	Construction of the Clarington TS to meet the needs of the growing eastern GTA and prepare for the eventual retirement of Pickering Nuclear Generating Station. Further details were presented in EB-2016-0160, Exhibit B1, Tab 3, Schedule 11, ISD D01.	2018

** As noted in ISD SS-08, Hydro One's transmission capital plan only includes the development work for this project at this time. The in-service date is based on the IESO's assessment that additional capacity is needed by the mid-2030s, but could potentially arise in the early 2020's under the high load growth scenario.*

[9] http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook *(Sept. 1, 2016)*

Projects 1, 3, 4 and 6 are being led by Hydro One, and Hydro One will be owning the facilities and carrying out the associated investments. Projects 2 and 5 are being led by parties other than Hydro One and many of the related facilities will be owned by those parties. Hydro One investments for these projects cover work required to enable these customer facilities to interface with Hydro One's transmission system. These investments are required to fulfil Hydro One's obligation in accordance with its Transmission License.

In addition to the major transmission projects listed above, the 2017 LTEP also identifies a number of regional planning projects that form part of Hydro One's 2020 to 2024 capital plans and which are summarized in Table 2 below. Two of these regional planning projects (Projects 2 and 6) mentioned in the 2017 LTEP are currently under construction and Hydro One expects the work to be completed by 2019. Furthermore, Projects 4 and 7 were completed and placed in service in 2018. However, these four projects have been included in the table for completeness.

Table 2: 2017 LTEP Regional Planning Projects

<table>
<tr><th>No</th><th>Region</th><th>Project Description</th><th>Need and Details</th><th>In-Service Date</th></tr>
<tr><td>1</td><td>North of Dryden*</td><td>New 230 kV transmission line from the Dryden/Ignace area to Pickle Lake.</td><td>Connect remote First Nation communities currently served by diesel generators. Further details are presented in TSP Section 3.3.8 ISD SS-02.</td><td>2020</td></tr>
<tr><td>2</td><td rowspan="2">Ottawa</td><td>Upgrade 115kV circuit A6R.</td><td>Provide increased supply capability for downtown Ottawa. Further details were presented in EB-2016-0160, Exhibit B1, Tab 3, Schedule 11, ISD D10.</td><td>2019</td></tr>
<tr><td>3</td><td>New transformer station and transmission line in South Nepean.</td><td>Meet growing electricity needs from new developments. Further details are provided in TSP Section 3.3.8 ISD SS-11.</td><td>2021</td></tr>
</table>

No	Region	Project Description	Need and Details	In-Service Date
4	Central Toronto	Investment in Runnymede transformer station.	Ensure new customers can be connected to the grid. Further details were presented in EB-2016-0160 Exhibit B1, Tab 3, Schedule 11, ISD D19.	2018
5		Investment in Horner transformer station.	Ensure new customers can be connected to the grid. Further details are presented in TSP Section 3.3.8 ISD SA-02.	2020
6		Investment in Copeland transformer station.	Ensure new customers can be connected to the grid. Further details were presented in EB-2014-0140 Exhibit D2, Tab 2, Schedule 3, ISD D10.	2019
7	Windsor -Essex	New transmission line and transformer station near Leamington.	Address growth and improve restoration timelines. Further details were presented in EB-2016-0160 Exhibit B1, Tab 3, Schedule 11, ISD D14.	2018
8		Refurbish the Kingsville transformer station.	Address growth and improve restoration timelines. Further details are presented in TSP Section 3.3.8 as part of ISD SR-05.	2022
9		Refurbish the Keith transformer station.	Address growth and improve restoration timelines. Further details are presented in TSP Section 3.3.8 as part of ISD SR-03.	2023
10	York Region	New transformer station in the City of Markham.	Address capacity and reliability in the York Region.	2026

** The 2017 LTEP also identified, in the North of Dryden region, a project to upgrade the existing transmission lines from Dryden to Red Lake, however Project 1 will result in reinforcing the Pickle Lake area thereby eliminating the need for the Dryden to Red Lake reinforcement.*

While the investments associated with Projects 2 to 5, and 7 to 9 are being led by Hydro One, the investments associated with Projects 1, 6, and 10 (as well as the new transformer station of Project 3) are in support of projects being led by parties other than Hydro One and many of the related facilities will be owned by those parties. However, as described above in the context of the major transmission initiatives, Hydro One needs to undertake certain investments to fulfil its obligation to enable those customer facilities to interface with Hydro One’s transmission system in accordance with its Transmission License.

The LTEP also discusses certain future transmission corridor requirements, which align with the IESO's Integrated Regional Resource Plan for the Greater Toronto Area. In particular, the northwest GTA has a long term need for a new transmission corridor to supply increased forecast demand in portions of Halton Region, Peel Region and York Region. Hydro One will be working with the IESO to further define plans for future development of the corridor.

Furthermore, the implementation plans put forward by the OEB and IESO to deliver on initiatives set out in the 2017 LTEP will potentially have an impact on the current planning processes (both bulk and regional) as well as the OEB's codes and requirements. Hydro One intends to be an active participant in the consultation and/or engagement sessions related to these activities and will continue to manage the transmission system in accordance with these processes, codes and requirements as required by Hydro One's Transmission License.

1.8 TRANSMISSION LINE LOSSES

In Hydro One's 2017-2018 Transmission Rate Application (EB-2016-0160), there was considerable discussion on how Hydro One deals with transmission line losses. The Board in its Decision and Order in that proceeding requested Hydro One to report on the following initiatives as part of its next rate application:

> *'Hydro One should work jointly with the IESO to explore cost effective opportunities for line loss reduction.*
>
> *Hydro One should also explore, as part of its investment decision process, opportunities for economically reducing line losses.'*

This Section describes the issues related to line losses on the transmission system and the steps taken by Hydro One in response to direction from the Board.

1.8.1 LINE LOSSES ON THE TRANSMISSION SYSTEM

Line losses occur in the transmission system as power flows from the generation source to the load. The amount of losses is dependent on the specific type of transmission line conductor, other transmission assets (i.e., transformers), the amount of power flowing in the line, and the length of the line. The line conductor and its length determine the resistance ("R") of the line and the power flow determines the current ("I") in the line. Transmission line losses are represented by the following equation:

$$\textbf{Transmission Line Losses} = 3 \times I^2 \times R$$

Where the '3' represents the number of phase conductors in the transmission line circuit.

Once the line has been built, the line resistance is fixed. However, current flow depends on many factors including network voltage and configuration, the amount of customer load and its location in regards to generation source location and output, time of day, weather conditions, etc. The load and generation is continuously changing and balancing these two elements across the system results in current flowing through the network. This effect has become even more pronounced with the introduction of renewable generation; where the output of the wind and solar generation plants varies constantly with the weather conditions. As a result, current flow and line losses on the transmission system vary from minute to minute.

Hydro One’s ability to manage line losses is limited to its role as a Transmission Owner (asset owner) in planning, selection, maintenance and operation of its transmission equipment, subject to the inherent limitations of that equipment.

There is typically little ability to cost effectively reduce line losses in line upgrade work where the existing conductor section is being replaced. The size of the conductor that can be considered is limited by the capability of the original tower structures and generally only conductors of the same size or one to two sizes larger can be accommodated. Changing to larger size conductors results in lowering line losses; however selecting a larger conductor size beyond the tower structure design capability, triggers major tower reinforcement work and is therefore not cost effective. Hydro One is increasingly using Aluminum Conductor Steel Reinforced Trapezoidal Wire (“ACSR/TW”) conductor in these situations. The ACSR/TW conductor has the same diameter as the conductor being replaced, but has more aluminum content and a 10 to 20% lower resistance. The net effect is to reduce the losses on that line by the corresponding amount.

Network reinforcements offer more opportunities for loss reduction. Building a new line in parallel with an existing line reduces the losses by 50% and building a third line in parallel with two lines reduces the losses by 33% assuming loading levels remain constant. Losses however, will increase with time as the load demand increases. Also, building these additional lines to reduce line losses is not economically justifiable unless the lines are required for providing capacity or increasing reliability.

Voltage upgrades also offer opportunities for loss reduction. Increasing the system nominal voltage (i.e. from 115kV to 230kV) can reduce line losses; as the current reduces by half in the 230kV system. However, similar to network reinforcement, a system voltage upgrade involves rebuilding transmission lines and station facilities and is not economically justifiable on its own merits, unless the lines are required for providing additional capacity or increasing reliability.

1.8.2 COLLABORATION WITH THE IESO

Managing the transmission system and reducing the associated transmission losses, is a split responsibility between Hydro One and the Independent Electricity System Operator (“IESO”). Loss mitigation measures are considered at all levels in the utility industry, from planning and the selection of the equipment to day-to-day system operations.

Hydro One and the IESO work collaboratively on transmission planning in two principal ways. Firstly, the IESO, in consultation with Hydro One, regularly performs bulk transmission planning to facilitate meeting supply mix and/or load growth. Secondly, Hydro One, as a lead transmitter, engages with the IESO (and the applicable local distributors) in regional planning activities to identify and recommend solutions to regional supply needs, as discussed further in TSP Section 1.2. For both bulk transmission planning and regional planning, while the recommended projects are primarily aimed at addressing specific reliability and system capacity needs, the recommended solutions also reduce line losses. Some of these projects are further discussed below in Section 1.8.5.

As a transmitter, Hydro One is responsible for the design, selection, and installation of equipment to address the needs that have been established through the transmission planning processes noted above. When designing solutions to address these transmission asset needs, Hydro One considers industry best practices such as: use of lower loss conductors and transformers, conductor bundling, insulator hardware systems to improve corona losses, and insulator assemblies and structure configurations to improve insulation losses. Some of these are further discussed below in Section 1.8.4.

As a system operator, the IESO directs the operation of the transmission system including maintaining voltage schedules, and generation dispatch to meet the load demand. Historically, the system has been operated to higher voltages, up to safe equipment limits, so there is little opportunity to further reduce losses. Losses are also a factor considered in the IESO's overall optimization of the generation dispatch. However, generation is selected so as to result in the lowest overall costs and not necessarily the lowest losses.

1.8.3 INDUSTRY PRACTICES

To explore effective opportunities for transmission line loss reduction, Hydro One requested the Electrical Power Research Institute ("EPRI") to review transmission line loss mitigation practices from other utilities and compare Hydro One practices with work done in other jurisdictions. EPRI is an independent, non-profit organization that conducts research, development and demonstration projects for the benefit of the public in the United States and internationally. EPRI's report can be found as Attachment 1 to this Exhibit and the results of EPRI's review are discussed here.

EPRI's review highlights that transmission line losses can be mitigated by transmitters through both planning and design practices. However, losses are not the utilities' primary driver for developing new transmission projects, rather losses are taken into consideration and mitigated where practical during the development of solutions to meet the primary need. The primary drivers for new transmission projects identified are:

- Security of supply;
- New connections;
- Generation integration;
- Economic;
- Market access;
- Loop flows; and
- Refurbishment.

Based on EPRI's utility survey, the methods being considered by other utilities to mitigate transmission line losses include:

- Raising Nominal Voltage;
- Optimization of Voltage Profile;
- Use Lower Loss Conductors;
- Re-direct Power Flows;
- Bundle Conductor Optimization;
- Improve Corona Losses;
- Shieldwire Segmentation;
- Improve Insulation Losses; and
- Installation of Low-Loss Transformers.

Overall, EPRI noted that Hydro One design practices are materially consistent with industry best practices for loss mitigation. The main conclusions of the EPRI report are as follows:

1. Transmission losses are not avoidable.

2. Losses can be mitigated to a limited extent with appropriate application of design.

3. Transmission losses and their mitigation are not a focal point of transmitters, their independent system operators, or their regulatory bodies. At best, a few entities include the impact on losses that various design options may have in the selection of their project solutions.

4. Transmission grids seldom operate at near-capacity levels. The generation – transmission grid – load network system is designed for reliability and economic electric delivery with contingencies for the loss of one or many elements.

5. Transmission projects are initiated based on system need to ensure adequacy and reliability of supply or provide supply to customers. No utility is pursuing loss mitigation projects solely based on the potential mitigated loss savings over the life cycle of the asset.

1.8.4 HYDRO ONE'S CURRENT PRACTICES AND STRATEGY

In Ontario, transmission line losses are not the primary driver for transmission investments because the transmission capital costs of implementing loss mitigation outweigh the loss reduction benefits over the life of the asset. However, line loss mitigation factors are considered in the planning process.

Planning for Reliability

Ontario's transmission planning criteria is focused on capacity in order to satisfy reliability requirements. The IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC") requires Hydro One to maintain sufficient transmission capacity in the design of the transmission system so that supply to customers is not interrupted when outages for planned work are required or when unplanned outages occur. For example, many of Hydro One's transformer stations have two independent sources of supply: two transformers supplied by two transmission circuits. At such stations, when a circuit and transformer are out of service, the remaining circuit and transformer are required to be capable of supplying the entire load of the station under forecast peak demand conditions. Therefore most transmission circuits and transformers are, on average, lightly loaded compared to their full capacity and losses in any individual circuit or transformer are small.

Voltage Considerations

The standard maximum operating voltage limits on Hydro One's transmission system are 550kV, 250kV and 127kV based on equipment limits. The transmission system is operated at or near these maximum voltages and therefore there is limited opportunity to reduce losses by further optimizing the transmission system voltage profile.

Increasing the system nominal voltage (i.e. from 115kV to 230kV) can reduce line losses. However, projects to change the nominal voltage are driven by reliability and adequacy needs. This is due to high costs as these projects require rebuilding the line(s) and replacing the station equipment. The projects identified below in Section 1.8.5 demonstrate the reduced losses due to system voltage upgrades.

Conductor Selection

When new investments are proposed and the selection of new equipment is evaluated, options to reduce line losses are taken into account. Using larger conductors results in lower line losses, however, the incremental capital costs for the larger conductor, supporting towers and other hardware that are needed to support the larger conductor must be weighed against the resultant reduction in line losses. The economic benefit of the line loss reductions is substantially less than the costs needed to make the infrastructure changes.

In an effort to promote continuous improvement, Hydro One investigates new conductor technology to mitigate line losses. For example, Hydro One tested Aluminum Conductor

Composite Core (“ACCC”) conductor as it has lower resistance than standard Aluminum Conductor Steel Reinforced (“ACSR”) conductors and is used by some utilities. However, this conductor had poor performance under ice loading conditions and is therefore, given the local climate, not suitable for use in Ontario. Currently, as previously stated, Hydro One employs ACSR/TW conductor which is a newer conductor technology with a lower resistance than standard ACSR of the same size.

Hydro One also uses bundled conductors where it is prudent to do so to increase the thermal capacity of a transmission line and/or mitigate corona. Bundling conductors also reduces the resistance of a transmission line and therefore also reduces losses. For example, Hydro One uses four conductor bundles for its 500kV system; and is using two conductor bundles on the 230kV system for the high capacity interconnection to Quebec, as well as for the 230kV conductor upgrade project from Merivale TS to Hawthorne TS (TSP Section 3.3.8, ISD SS-06).

Transformer Selection

In addition to selecting the type of conductor, losses are also factored into the tendering of new transformers. As noted in EB-2016-0160, Hydro One includes “both the cost of core and full load losses into the tender specifications to manufactures for their design and bid. Hydro One selects the best overall equipment considering needs, performance and costs, including losses.”[1] Hydro One’s practice in this regard has been consistent over the years.

A summary of Hydro One’s current practices for each of the loss mitigation strategies and methods considered by other utilities, as described in EPRI’s report, are presented in Table 1 below. The EPRI report concluded that Hydro One’s design practices are aligned with industry best practices for loss mitigation.

[1] EB-2016-0160, Transcript Volume 5, page 39

Table 1: Summary of Hydro One's Loss Mitigation Practices

Methods	Hydro One’s Practices
Raising Nominal Voltage	Due to expense, increasing the system nominal voltage is driven by reliability and adequacy needs. Hydro One will continue to evaluate opportunities to convert 115kV systems to 230kV operation for cost effectiveness and reduction of losses.
Optimization of Voltage Profile	Hydro One’s transmission system is already operated at voltages that are at or near equipment limits and therefore there is limited opportunity to reduce losses by further optimizing the transmission system voltage profile.
Use Lower Loss Conductors	Hydro One currently uses lower loss conductor (i.e., compact ACSR/TW conductors) for capacity needs. Hydro One will also continue to consider the use of larger conductors with a corresponding lower resistance, where cost effective.
Re-direct Power Flows	Power flows at any given time are dependent on the connected load and generation. Losses are a factor considered in the overall optimization of the generation dispatch by the IESO.
Bundle Conductor Optimization	Hydro One currently uses bundled conductors for 500kV and some 230kV lines.
Improve Corona Losses	Hydro One implements insulator hardware systems that have been designed to eliminate corona. Conductor sizes are also selected to avoid corona.
Shieldwire Segmentation	Hydro One does not use shieldwire segmentation due to high tower ground potential rise.
Improve Insulation Losses	Hydro One considers losses during insulation coordination design of insulator assemblies and structure configurations.
Installation of Low-Loss Transformers	Hydro One’s purchase specifications already include cost of losses. Hydro One assesses the vendor transformer quotations and designs based on best overall economic benefit including losses.

1.8.5 HYDRO ONE'S PROPOSED CAPITAL PLANS THAT WILL HAVE A LINE LOSS REDUCTION BENEFIT

Hydro One has incorporated line loss reduction benefits into Hydro One's proposed capital plan as demonstrated in Table 2. These development capital projects have been identified through the planning processes, and although loss reduction is one of the benefits, it was not the primary driver for any of these projects. All of these projects are outcomes of regional planning studies and are primarily driven by need to support load growth, with the exception of the "Merivale TS to Hawthorne TS: 230kV Conductor Upgrade" project which is needed to optimize the use of the existing interconnection between Ontario and Quebec, in addition to supporting future growth.

Table 2: Capital Investments that have Incorporated Loss Mitigation Methods

ISD #	Investment Name	Reduction in Peak Losses*	Loss Mitigation Method Incorporated
SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	1.4 MW	Increasing the conductor size on existing circuits reduces resistance which in turn reduces losses.
SS-09	Barrie Area Transmission Upgrade	0.6 MW	Converting the supply to Barrie to a higher voltage (from 115kV to 230kV) reduces current flow which in turn reduces losses.
SS-11	South Nepean Transmission Reinforcement	0.7 MW	Converting an existing single circuit supply to a double circuit at higher voltage reduces current flow which in turn reduces losses.
SS-12	Aylmer-Tillsonburg Area Transmission Reinforcement	1.5 MW	Reconfiguring the network and building a short section of line to provide dual supply to the area creates a parallel path for current which in turn reduces losses.
SS-14	Southwest GTA Transmission Reinforcement	0.8 MW	Converting an existing idle line to a higher voltage (from 115kV to 230kV) creates a parallel path for current which in turn reduces losses.

** This represents the loss reduction in the peak hour. At other times the loss reduction will be smaller.*

1.8.6 FUTURE

Hydro One will continue to consider the reduction of line losses for all projects and will work collaboratively with the IESO to identify and investigate other opportunities to reduce line losses as part of the regional planning process. Hydro One will also continue to participate in industry affiliations to keep abreast of the developments in loss reduction and other new technological opportunities.

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Hydro One Transmission Losses

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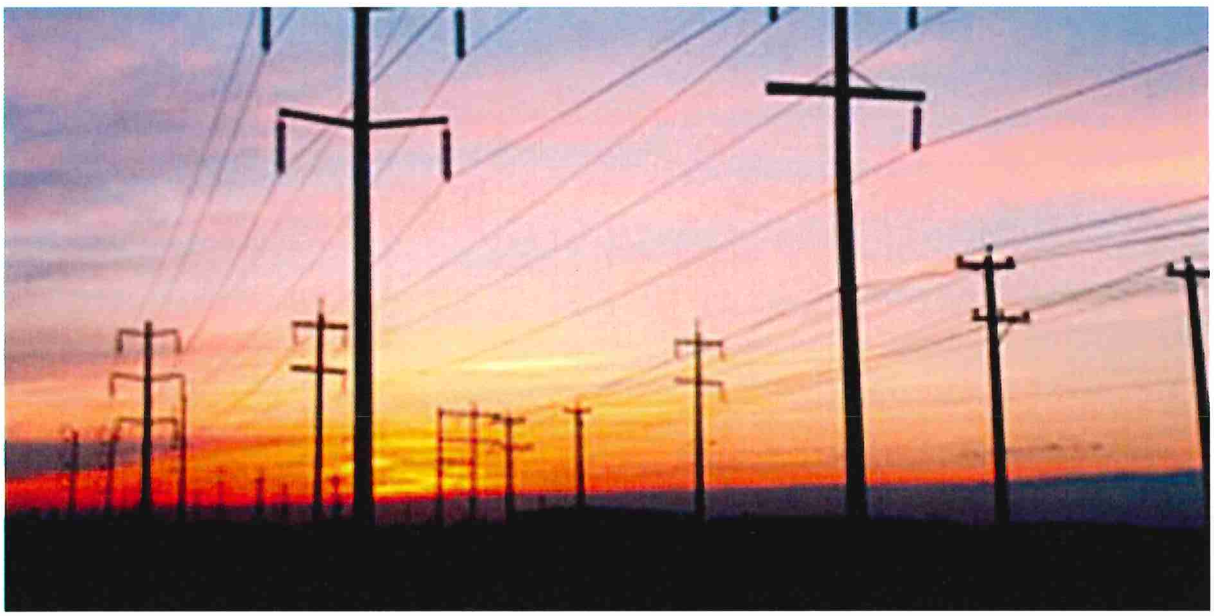

Hydro One Transmission Losses

3002012721

Technical Report, March 2018

EPRI Project Manager

J. Chan

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

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The Electric Power Research Institute (EPRI) prepared this report:

Principal Investigators
J. Chan

T. Goodwin
Tip Goodwin Consulting, LLC
Southlake, TX

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ABSTRACT

Hydro One requested EPRI's assistance in preparing a best-practices review of the electric transmission industry concerning how transmission line and transformer losses are being addressed across the industry, and also a review of Hydro One's own efforts at mitigation of transmission losses.

To meet the request, this report presents an overview of what causes losses within the transmission grid, how different mitigation techniques are applied to reduce losses, how the industry is addressing loss mitigation in its planning and capital improvement programs, and obstacles preventing direct loss mitigation efforts. The report also describes Hydro One's accomplishments in mitigation losses on its system and discusses the results of a sensitivity study of 11 Hydro One transmission assets, addressing the magnitude of losses incurred over a year and the impact potential mitigation efforts would have on the level of losses.

The investigation of industry best practices and Hydro One's efforts at mitigating transmission losses showed these key points:

1. Transmission losses and their mitigation are not a focal point of transmission service providers, their independent system operators, or their regulatory bodies. At best, a few entities include the impact on losses that various design options may have in the selection of their project solutions.
2. Transmission Projects are initiated based on system need to ensure adequacy and reliability of supply. No utility is pursuing loss mitigation projects solely based on the potential mitigated loss savings over the life cycle of the asset.
3. The industry's best practices address transmission losses during the design and purchase of assets, such as: reducing losses with proper conductor selection and transformer design.
4. Hydro One design practices are materially consistent with industry best practices for loss mitigation.

Keywords
Energy Efficiency
Losses
Transmission Line

EXECUTIVE SUMMARY

Electric utilities are facing continuing growth in demand for reliable, high-quality, low-cost electricity to meet everyday demands and expanding applications of electricity. To meet these demands, utilities are employing a mixture of increased system efficiencies, conservation efforts, controlled capital expenditure, and a diverse injection of distributed generation, mostly renewable.

Following the Ontario Energy Board's decision in Hydro One transmission rate application, Hydro One (with support from the IESO) requested EPRI to carry out a comprehensive assessment of current best practices in the industry relative to the mitigation of losses in transmission line and station equipment.

The study investigated the current best practices relative to how transmitters, independent system operators, and regulatory bodies are addressing the loss mitigation concern. The research explored how transmission losses occur, the chief sources of losses, the methods employed by utilities to mitigate losses through reducing equipment resistance and upgrading voltage levels, and the incorporation of loss mitigation from a system planning perspective. While driving for a goal of more efficient delivery of electricity, the electric utility industry does not pursue rebuilding and upgrading existing facilities solely for loss mitigation. The lifetime benefits of the mitigated losses do not offset the financial cost of performing the necessary transmission line modifications. In addition, the majority of transmission assets operate at levels 30-40% of their capacity, only operating near capacity a few hours a year if at all. The low load factor means transmission lines generally do not create significant losses and loss mitigation has an even smaller impact.

The study was also intended to better understand Hydro One's own transmission loss mitigation efforts in the context of these industry best practices. The project reviewed Hydro One's accomplishments in loss mitigation to date. A sensitivity analyses was also performed using characteristic data from nine transmission lines and two transformers in the Hydro One system. To assess the potential loss mitigation levels, an assessment was conducted on the level of losses that occurred in 2016 based on available element loading patterns and equipment characteristics for the subject transmission assets and a set of more efficient transmission conductors and transformers that are available.

The investigation in best practices and review of Hydro One's current practices showed these key points:

- Transmission losses and their mitigation are not a focal point of transmitters, independent system operators, or their regulatory bodies. At best, a few entities include the impact on losses that various design options may have in the selection of their project solutions.
- Transmission Projects are initiated based on system need to ensure adequacy and reliability of supply or provide supply to customers. No utility is pursuing loss mitigation projects solely based on the potential mitigated loss savings over the life cycle of the asset.
- The industry's best practices address transmission losses during the design and purchase of assets, such as: reducing losses with proper conductor selection and transformer design.
- Hydro One design practices are materially consistent with industry best practices for loss mitigation.

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Objective

Electric utilities are facing continuing growth in demand for reliable, high-quality, low-cost electricity to meet everyday demands and expanding applications of electricity. To meet these demands, utilities are employing a mixture of increased system efficiencies, conservation efforts, controlled capital expenditure, and a diverse injection of distributed generation, mostly renewable.

Following the Ontario Energy Board's decision in the Hydro One transmission rate application, Hydro One (with support from the IESO) requested EPRI to carry out a comprehensive assessment of current best practices in the industry relative to the mitigation of losses in transmission line and station equipment. The study investigated the current best practices relative to how transmitters, independent system operators, and regulatory bodies are addressing the loss mitigation concern.

The study also assessed how Hydro One is applying the identified best practices in loss management and provided examples of loss mitigation efforts.

Background

Efficiencies are required to address the differences between demand-driven project requirements and the available capital investment in infrastructure that utilities can commit. Efficiency is also critical due to changes in load and the unpredictability of the availability of renewable generation. To address these challenges, utilities are pushing their aging infrastructure to provide a longer service life, and to carry increased loading to meet the demand.

An important aspect of this interaction is the fact that the electric utility infrastructure is aging. Although the book life from an economic standpoint of a utility asset is typically 40 years, its service life in most cases can be exceeded with appropriate maintenance. Utility assets typically are removed or replaced only for failure, end of life, or inadequate capacity. For example, a conductor may be in-service for many decades; and is removed only when increased capacity requirements lead to a reconductoring of the line, or as a result of weathering, the conductor deteriorates and needs to be replaced. Hydro One has been proactive in asset management of existing facilities, identifying infrastructure and equipment that has reached or is reaching its end of life, and is taking steps to repair, or maintain as appropriate, equipment to extend its life.

With time, system topology grows and changes with various load, transmission capacity and generation injection changes. Existing facilities are very seldom removed completely. Rather, the assets are modified or upgraded as needed. One aspect that remains constant with each specific asset is its characteristics relative to current-carrying capability and its associated resistance. Transmission losses are intrinsically related to the resistive properties of the equipment, which cannot be altered. Therefore these parameters may mean the equipment or asset is not as efficient as newer designs and applications of technologies that have been applied in newer-technology equipment.

This report will address the characteristics of losses in current technology applied on transmission systems and what newer-technology has to offer in loss mitigation. The report also addresses what the best practices are being applied across the electric utility industry related to loss mitigation and how Hydro One is applying loss mitigation efforts in managing their transmission system.

2
LOSSES WITHIN THE TRANSMISSION SYSTEM

The section provides a brief overview of how transmission losses occur in an electric utility system and the impact of these losses on electricity delivery.

Sources of Losses

Losses on the transmission system can be attributed to the system configuration/topology as well as the equipment characteristics.

System Configuration/Topology

The size, configuration and topology of the transmission system have a large impact on the amount of losses that can be incurred. As the following section on Equipment Characteristics will disclose, each type of equipment has loss characteristics. Some are fixed per piece of equipment, e.g., the losses associated with a transformer; while other characteristics are attributed to size, e.g., length of a transmission line and kilometers of conductor in operation or voltage class of equipment which influences losses.

Hydro One's transmission system is very large, with substantial distances between generation sources and load demand centers. The transmission system is also an aging asset with lines and equipment that are older technologies that are less efficient than newer technology equipment. Older transmission lines that traverse many kilometers typically used smaller conductors which were adequate based on loading at that time. These lines contribute a large portion of the losses incurred as loading levels have increased. As the transmission system changes to meet reliability and load demand, the topology changes with newer assets added as greenfield installations or as upgrades and replacements of existing assets to meet capacity requirements.

Evolving Industry

The electricity industry is experiencing a new paradigm relative to providing a network to provide cost-efficient and reliable energy to its consumers. At one time, utilities operated in a monopolistic environment and did their planning and design, construction, and operation to meet their specific customer needs. With deregulation, open access allows any company with the wherewithal to build generation. Initially, these new generation forays were by utility or ex-utility interests using typically identifiable sites at the juncture of fuel and water sources and high-voltage transmission lines. That was the first wave, and the transmission grid had to expand to provide adequate transmission capacity to move power from these new nodes to an unconfined array of load nodes.

The next wave of generation encompassed larger-scale renewables. Initially, these facilities, too, were at logical large-scale sites, often remote due to size, which required transmission expansion. Now the size and site-ability of renewable generation mean that it can be placed anywhere. This flexibility creates new constraints and contingency scenarios on both the distribution and transmission grids in their areas.

Transmitters have been required to maintain open access to any requester, and to expand, upgrade, or rebuild many of its assets to meet the new and/or modified load and generation. The most difficult aspect of this expanding market is that it is less than predictable when it comes to reliability. Renewable generators are predominantly fueled by wind and solar and therefore depend on favorable environmental conditions to generate power. However, the transmission system is required to provide capacity whether these renewables are on line or not on line. Thus the transmission system must be designed for both of these two operating scenarios which often require a diametrically different transmission system. Power will flow in one pattern with congestion constraints when renewables are on and a different pattern when they are not.

Daily market drivers (load demand, generation bid pricing, equipment outages, system congestion) make the electric industry a dynamic environment where assets from generation through transmission, and substation are required to perform differently on an hourly basis. For example, the load, which may have been supported by a few large scale generation sources in the past, may now be supported by multiple small scale generation sources throughout the network or a combination of both the large and small-scale generation. The transmission system will need to support each of these delivery path scenarios reliably. The transmission system has become a dynamic topology, physically and operationally.

Equipment Characteristics

Transmission equipment experiences losses while transmitting power. This is a normal and accepted phenomenon in the electrical industry. The amount of losses is governed predominantly by two parameters, which have passive and dynamic aspects.

Passively, the losses are determined, first, by the resistance of the current-carrying component—e.g. the higher the resistance of a conductor, and the longer the length of the conductor, the greater the thermal losses, and, second, by the associated equipment construction—e.g., the core construction of a transformer. These parameters are fixed once the asset is manufactured and installed.

Dynamically, the losses are proportional to the amount of power flowing through the asset, squared. With an ever-expanding demand for capacity, the current level generally increases and the losses increase.

Transmission Lines

Conductors, whether elevated in open air or buried in underground facilities, have a known resistance, which creates heat when the current flows through them. The only alternatives to reduce losses are to use a different conductor with lower resistance or to reduce the current flowing through the equipment.

Any elements within the transmission path that carry current are sources of losses due to joule heating.

Joule heating losses are proportional to the square of the current load. The joule heating causes two operating issues—namely, conductor elongation and increased resistance. The conductor elongation is a driving influence on transmission line design dictating span lengths and structure heights. The elevated resistance accentuates the joule heating with power flow, increasing losses.

On a much smaller scale, losses are attributed to corona discharge around hardware and to conductor and field effects induced on parallel metallic objects, such as pipelines, other electric circuits, railroads, etc. Fortunately, current design practices have reduced these contributions to minimal levels.

Corona consumes energy, creating a line loss, as it ionizes air around energized parts of insulator assemblies and along the conductor. Corona only occurs at high voltage levels, increasing in severity as voltage rises above 230 kV. The voltage causes a gradient around all energized parts. Generally, the shape of the components is smooth enough that the voltage gradient is fairly smooth and low. However, if the surface is rough and has some protuberances, the voltage gradient is distorted, causing high gradient transitions. If the gradients are large enough, the energy causes ionization of the air and corona. The phenomenon requires a high base voltage (i.e., EHV level) and a protuberance (e.g., water droplet ready to drop from the surface, a metal nick sticking out, or bird droppings).

Station Equipment

Equipment, such as transformers, breakers, and switches, have internal current carrying components that are like conductors fixed in their resistive characteristics. Transformers have an additional component of losses associated with the core construction of the transformer and induced currents through them. Newer designs and core materials have provided increased efficiencies that reduce the transformer losses, but their application requires replacement of the existing assets.

Station equipment, breakers, switches, bus conductors and metering equipment all create a small contribution to system losses. Mitigation of losses in stations is limited since the majority of the equipment is sized for withstanding fault levels of current which dictate the design and sizing of components.

Overall, transformers drive station losses and are the focal area for loss mitigation.

Transformer losses have both voltage-related and power-flow-related losses. Voltage-related losses are associated with transformer construction and core materials. Eddy currents develop within the core that contributes to the losses. They are induced by the voltage level and occur anytime the transformer is energized.

Power flowing through the transformer coils experiences losses from the joule heating due to conductor resistance. The level of these losses is proportional to the square of the current flowing through the transformer.

Losses are also incurred from the auxiliary devices on transformers that assist in cooling the unit. Pumps for passing the mineral oil through radiators and fans blowing air across the radiators are used on some units to cool the units. These losses become proportional to the transformer load; the more load transferred through the transformer, the hotter the unit becomes.

Impact of Losses

Losses represent energy, or units of electricity that must be created in the process of generating electricity to replace energy lost. Replacing lost energy has several impacts on the electric system.

Each unit of energy lost must be generated, requiring additional fuel sources. Additional generation capacity may be needed if the cumulative losses cause demand greater than the installed capacity. Additional generation may also cause additional pollutants and environmental impacts depending on type of generation source.

Similarly for transmission lines, additional capacity may be required on certain lines to meet demand at load points. Meeting this demand may require new lines, upgrades, or some other measures to ensure a reliable transmission system.

EPRI performed a study for the New York State Energy Research and Development Authority to assess the level of electric losses across the electric production, delivery and use spectrum. Cumulatively, transmission losses average 1.5 to 5.8%.[1]

An important factor in reviewing the impact of losses on transmission lines is the actual loading that most lines experience under normal operation compared to the actual load-carrying capability of the line. If losses are estimated on capacity, they give a false representation of the actual system losses. This point will be expanded upon in the discussion in the Sensitivity Study in Section 5.

[1] *Assessment of Transmission and Distribution Losses in New York*, EPRI, Palo Alto, CA: 2012. PID071178 (NYSERDA 15464).

3 LOSS MITIGATION METHODS

This section reviews constraints to loss mitigation, several general principles related to loss mitigation, the results of utility surveys on loss mitigation efforts, and methods of mitigating losses through reducing equipment resistance, upgrading of voltage level, and power flow control.

Loss Mitigation

Loss mitigation reduces overall demand on the transmission system by requiring less power from generation. However, due to the geographic nature of the power system, a reduction in losses doesn't necessarily lead to fewer transmission and/or distribution facilities. These facilities are still required to serve customers across the utility's service territory.

One of the major constraints to pursuing loss mitigation is the need to justify the benefits of the loss reduction versus the capital expenditure to execute the mitigation. Unfortunately, in most cases, the benefits do not offset the cost of mitigating losses, even when considering the life cycle economics. Initiating and funding projects for the sole purpose of mitigating transmission losses are not typical throughout the industry. Rather the economic benefits realized from different aspects of a project that mitigate losses are part of the life cycle cost analysis of a project that may sway approval of a project or make one project a better choice over another solution. In reality, today loss reduction is driven by available opportunities, not direct need.

Key Principles Related to Loss Mitigation

Through EPRI's research, a framework around improving transmission efficiencies (including transmission losses) and a methodology for measuring the potential benefits has been developed. The key principles related to transmission efficiency that have been identified are:

- **Efficiency is more than simply reducing losses**: A more economically efficient transmission system that fully utilizes existing assets and incorporates renewable energy sources and storage technologies may actually have higher losses.
- **Efficiency initiatives should not reduce reliability**: Transmitters (e.g., Hydro One) and system operators (e.g., IESO) must focus their efforts first on reliability to meet customer and regulatory expectations. In a simple example, removing a transformer that is not carrying much load may reduce some of the core losses but introduce risks to reliability if another transformer is lost.
- **Efficient transmission will require new and upgraded systems:** The expansion of the grid to meet the challenge of adding renewables and storage capabilities to meet load growth and to replace retiring infrastructure will offer significant opportunities to improve the efficiency of the transmission system. However, the application of better equipment and new technologies and the replacement of less efficient retiring equipment are part of a long-term process that will take many years.
- **Efficiency must be considered in business cases**: Transmission system expansion and refurbishment must incorporate efficiency considerations in the development of projects.

- **A regulatory framework with incentives is needed to encourage transmission loss reduction**: For loss reduction to be a prioritized criterion requires regulatory change to incentivize it. Currently the life cycle benefits of loss mitigation are not large enough to make direct loss mitigation projects justifiable.

These findings have been documented in several reports including:

Transmission Efficiency Technology Assessment: Phase 1. EPRI, Palo Alto, CA: 2008 1010692.

Transmission Efficiency Initiative: Key Findings, Plan for Demonstration Projects, and Next Steps to Increase Transmission Efficiency. EPRI, Palo Alto, CA: 2009. 1017894.

Transmission System Efficiency Technology and Methodology Assessment, EPRI, Palo Alto, CA: 2010. 1020143.

Transmission System Efficiency and Utilization Improvement: Summary of R&D Activity and Demonstration Projects. EPRI, Palo Alto, CA: 2012. 1024345.

Utility Practices on Loss Mitigation

This section lists some of the results of the studies and important factors that other utilities are considering to reduce transmission losses.

New York State Study

Losses can be mitigated in several ways. EPRI performed a study with the New York State Energy Research Development Authority[2] reviewing the issue of line losses in support of NYSERDA's larger investigation into Electricity Efficiency improvements across the state. The New York investigation is much broader than transmission line losses and focused on other efficiency initiatives; but EPRI was asked to participate to provide visibility to the transmission loss impact.

Each utility provided some insight into their current loss calculation methodology and mitigation actions. In general, losses were not tracked or directly measured throughout the industry. Transmission losses were obtained based on a high-level view—measured sales versus generation input.

The utilities also noted the ways they are looking at mitigating losses. Of the eight utilities participating in the project, the following methods were being applied:

- Reconductoring projects (seven utilities)

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[2] *Assessment of Transmission and Distribution Losses in New York.* EPRI, Palo Alto, CA: 2012. PID071178 (NYSERDA 15464).

- Application of capacitors and shunt devices for reactive power control (five utilities)
- System operating methods for voltage control (two utilities)
- Replacing substation transformers (two utilities)
- Voltage upgrade of circuits (two utilities)

EPRI Utility Survey

Through a utility survey, EPRI researched energy efficiency activities with utilities related to transmission line losses.[3] Table 3-1 provides a summary of the loss mitigation efforts being considered and applied by the 25 EPRI survey respondents, including investor owned, public power, cooperatives, transmission providers, and federal utilities. The respondents covered voltages from 115 to 765 kV. Note that, while many options are being considered, few methods are being actively applied, and few utilities are actively pursuing the efficiency efforts.

Table 3-1
Transmission Loss Mitigation Areas of Interest

Methods Under Consideration	Under Consideration (%)	Actively Applying (%)
Raising Nominal Voltage	33	4
Optimization of Voltage Profile	22	0
Use Lower Loss Conductors	56	0
Re-direct Power Flows	44	8
Bundle Conductor Optimization	11	0
Improve Corona Losses	11	0
Shieldwire Segmentation	22	0
Improve Insulation Losses	11	0
Installation of Low-Loss Transformers	56	8
Convert to DC, Bipole or Tripole	0	0
Switch off Equipment Not in Use	0	0

The survey asked whether the utilities were conducting loss studies. Of the 25 participants, 29% responded that they had done loss studies on lines and some transformers. However, only 14% reported that they had used measured data for their investigation.

When asked by EPRI why the loss studies were performed, 36% reported they needed the data for a rate or regulatory filing. Billing of transmission services accounted for 36% of the reasons. Again the application of actual data in loss quantification was only in 28% of the cases.

[3] *Transmission Efficiency Technology Assessment: Phase 1*, EPRI, Palo Alto, CA: 2008. 1010692.

The survey further asked whether the loss considerations were at peak loading. Of the 56% percent that responded, 70% said they made their analysis at peak loss levels using computer simulations, SCADA data was used 25% and 5% were based on transmission studies.

The EPRI study summarized that loss mitigation within the transmission system can be addressed in three general concepts: equipment characteristics, voltage level, and power flow control. In many cases, aspects of these three concerns interplay and contribute collectively to losses and their mitigation. For example, the resistance of the conductors and the amount of current flowing through the conductor define the losses. The greater the current flow, the higher the losses. Coincidentally, the losses are the result of resistance heating; the heat rise causes the conductor resistance to increase, coupling to further cause losses. Voltage and current levels can mitigate congestion—increased power can be accomplished with higher voltage and less current or by maintaining voltage and increasing current. Since losses increase by the square of current flow, I^2R, voltage increases and lower currents improve losses

Equipment Resistance

Joule resistance heating is the greatest contributor to transmission equipment losses. The majority of transmission lines are constructed using electrical grade EC 1350 aluminum strands for current-carrying capacity. Various constructions are available using aluminum alloys, steel, or composite materials for providing additional mechanical strength to the conductor. Figure 3-1 shows cross sections of a traditional steel core ACSR conductor and an ACCC composite core conductor. Typically, a core stranding provides the mechanical strength and supports the aluminum strands. The number of strands and their diameters build up a cross-sectional area that is sized to provide the desired current-carrying capacity. The strand resistance causes joule heating when electrons flow through the conductor, creating a temperature rise. The temperature rise has two effects on the conductor: first, it causes thermal elongation in the strands, which cause the line conductor to expand and sag more. Second, the increased heat causes the resistance to slightly increase, causing additional thermal losses.

Figure 3-1
Comparison ACSR and ACCC

On any given operating day, the ambient conditions of temperature, wind, and solar radiation affect the thermal stability of the conductor catenary system. As current flows, heat is created from the resistance heating. In addition, under daylight conditions, solar heating can occur. The ambient temperature serves as the base thermal setting. The hotter the ambient, the higher the conductor temperature; conversely, cool days and night reduce the thermal content. Wind blowing across the conductor also cools the conductor. Under power flow, a quasi-steady-state condition develops, where the heat being introduced by resistance and solar heating is balanced by the ambient temperature and wind effects. The transmission line is designed such that the conductor temperature remains below a certain operating temperature with the design power flow. Structure type, heights, and strengths are determined by the conductor selected and the terrain and environmental loadings that will govern design for safety and reliability concerns. Larger conductors provide lower resistance and losses but require taller and stronger structures to perform as required. Thus, a life cycle cost evaluation must be performed of the initial capital expenditures, maintenance costs, cost to deliver power (including losses), and service life.

Figure 3-2 illustrates the cost development of a transmission project, including capital costs and the cost of electrical losses on the transmission line. The Present Worth of Future Requirements for Revenue (PWRR) is the present worth sum of the cost to build a line (increasing cost with increase in diameter) plus the present worth of the future savings attributed to line losses (lower cost of losses with increase in conductor diameter). A range of conductors provide an optimum life cycle cost.

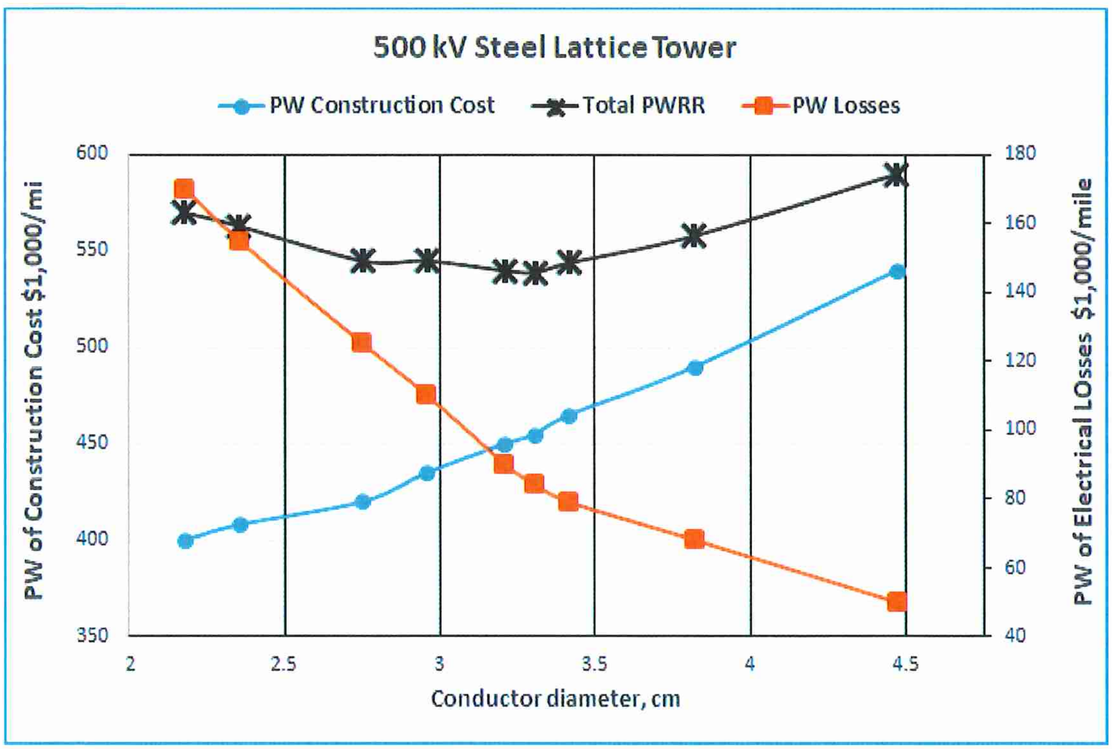

Figure 3-2
Lifetime Cost as a function of conductor diameter

With the different types of conductors available, and various sizes and strandings, an optimization study can be performed to select a conductor that will provide the capacity desired, while maintaining code clearances, optimizing life cycle costs, and mitigating line losses. One of the caveats of conductor selection is that a different conductor could be the best fit for each project. This is not a practical solution, however, for transmission providers to design a transmission line for each unique situation. The costs of maintaining and building unique designs are too high. Rather, utilities typically develop classes of capacity designs that optimize the design and life cycle costs for a manageable number of designs to meet transmission needs. This is particularly true for new construction.

When looking at increasing capacity on existing lines, an economic study is required to select a solution that has supportable life cycle costs. Some projects can be solved with re-conductoring the line on existing structures, with or without modest modifications. Advancements in conductor designs using composite materials for the mechanical support have made this solution viable in many cases. However, some upgrades require significant additional capacity that requires line reconstruction. These solutions revert back to the optimized solutions based on new construction design packages. Note: one of the issues with many of the composite core conductors is their inability to provide conductor sag within acceptable clearance limits.

Voltage Level

Power is equivalent to the Voltage times the Current (VI). So, for an equivalent level of power transmission, the lower the voltage, the higher the current level must be. Increased current means increased line losses. Operating lines at higher voltages reduces losses.

In day-to-day operations, voltage levels fluctuate on lines by a manageable few percent. These changes are not sufficient or intended to mitigate losses. Slightly larger voltage changes are accomplished with Load Tap Change (LTC) transformers, intended for voltage control and reliability concerns. Again, LTCs are not loss mitigation measures, but are a technology to maintain voltage levels at the ends of long transmission lines and power quality.

Transmission grids are developed around specific voltage classes of construction to appropriate bulk power levels. For example, common transmission voltages at a utility may include 69, 138, 230, and 500 kV. Other combinations could be 138, 230 and 345 kV or various combinations of 69, 115, 138, 230, 345, 500, and 765 kV. Changing a voltage class typically calls for a change to a higher level that requires significant system changes. For example, insulator assemblies need to change out to higher class voltages requiring more space, new structure geometry, and probably a complete rebuild. The voltage upgrade becomes a complete rebuild. Voltage upgrades also affect customer equipment and facilities, requiring added expense at their stations, which must be borne by the customer.

EPRI has performed studies and developed a guideline for voltage upgrades that require minimal structure modifications, *Feasibility of Increasing Transmission Line Capacity by Voltage Upgrade.* EPRI, Palo Alto, CA: 2007, 1013984.

EPRI and AEP performed a study investigating the benefits of an overlay EHV system. This example is greater in scale than evaluating the benefit of upgrading the voltage class of a single line, but it exemplifies that grid efficiency can be significantly enhanced when a "large" EHV overlay is used to improve the overall performance of a grid's region. *Evaluation of Efficiency and Utilization Benefits from Extra High Voltage Transmission Overlay.* EPRI, Palo Alto, CA: 2011, 1024617.

Power Flow Control

Since current-driven losses are the most significant driver for line losses, controlling the amount of current that flows through a given line section could reduce losses. Power sources provide electricity which follows the path of least resistance to the points of load.

Another important factor in power flow control and grid operations is that the grid topology changes constantly. It changes from continuous completion of transmission, load, and generation projects. As load changes by the connection of new load points and demand at existing points, the grid itself is inherently dynamic in responding to that load, changing the power flow levels and paths constantly. Interconnection of generation changes due to traditional generation connections, distributed generation, and the burgeoning smart grid impacts constantly changes the flow patterns across the grid. Topology changes daily due to the outages taken to complete emergency as well as planned maintenance on equipment throughout the grid.

Methods used by utilities to "direct" flow include:

- Phase shifters can be used to direct flow over a transmission path.
- Direct Current technology is another way to gain some control over the flow of current. The cost of DC station equipment makes this option viable only for long distance, bulk power transfer over 450 km without intermediate stations.
- Another option is using Flexible Alternating Current Transmission Systems, FACTS. FACTS equipment allows control of the impedance of a line and can direct power down some paths rather than others. FACTS is also typically applied to bulk power transfer lines over longer distance to control reliability characteristics and enhance efficiency.

The power flow control systems require installation of sophisticated equipment at key locations. The solutions noted are not applicable to local issues, but are typically applied for issues that arise for long-haul bulk power transfer cases.

Summary on Loss Mitigation Methods

Loss mitigation can be achieved through application of a variety of technologies including application of equipment that create fewer losses at the same power flow, controlling power flow through lines to prevent high losses attributed to less efficient assets, and upgrading assets to a higher voltage class. Unfortunately, these changes cannot easily be applied to existing assets; they require upgrading, reconductoring or construction of new transmission assets.

Surveys of have shown that the preferred options under consideration are:

- Use of Lower Loss Conductors
- Installation of Low-Loss Transformers
- Raising Nominal Voltage
- Optimizing Voltage Level
- Re-direct Power Flow

One other key aspect is that Reliability is the driving force in transmission system development, maintenance and operations. Efficiency is an aspect of consideration but does not drive or initiate projects.

4
SYSTEM PLANNING PERSPECTIVE

This section summarizes the best industry practices for incorporating loss mitigation in system planning efforts. It reviews different kinds of system planning efforts, including customer connection projects, reliability projects, and economic relief projects. The section also looks at the process of project selection and development, the findings of a CIGRE survey on drivers for transmission investment, how refurbishment and end-of-life drives transmission projects, and a US Department of Energy analysis of opportunities for energy efficiency.

Transmission lines are justified and planned based on capacity requirements. Capacity requirements are attributable to a snapshot in time with a certain transmission grid topology, generation mix, and forecast load built in a nodal model of the grid. Numerous scenarios are configured and run against the transmission grid to test the reliability level of operation and to identify cost constraints due to congestion patterns. The results of those runs identify deficiencies in the grid—i.e., elements in the grid that are inadequate in capacity and become reliability or congestion constraints during scenario solutions. When a threshold of concern established by the responsible operating manager is reached, added transmission assets may be required. Many of the transmission elements are only governed by a few or a singular contingency scenario. Under those conditions, that transmission asset's full capacity may be required. Under all other conditions, that element may be loaded at a significantly lower level. One of the critical aspects of transmission operations, planning, and design is that capacity is required for reliability first, and for congestion cost possibly second. Lightly-loaded lines are the grid's insurance against the contingency.

Responsibility Roles

The responsibility for managing the transmission facilities, and the losses that are realized, is a split responsibility. Mitigation of losses, or the process that leads to mitigation, occurs in all aspects of the utility industry, from the selection of the equipment to the day-to-day decisions on operations. The transmitter such as Hydro One, is responsible for managing transmission assets (e.g., lines, transformers, etc.); and bulk system planning as well as generation dispatch and flow control are the responsibility of the grid system operator, such as the Independent Electricity System Operator (IESO) in the case of Ontario.

Planning for grid enhancements is a shared responsibility between the System Operator (the IESO in Ontario) and the associated Transmitters (such as Hydro One in Ontario).

In Ontario, the provincial Minister of Energy has the authority to set policy objectives for transmission and distribution planning. The Ontario Energy Board established the province's regional planning process framework, which it advances through codes and license conditions.

In Ontario, bulk system planning is carried out by the IESO to ensure sufficient resources are available to meet Ontario's electricity needs, and that the transmission system is capable of delivering electricity to consumers in a reliable and cost effective manner. When designing solutions to address transmission needs, the IESO works collaboratively with stakeholders, including Hydro One, Distributors, and Direct Customers.

At a regional level, planning in Ontario is coordinated between the IESO, Transmitters and Distributers, following the Process for Regional Infrastructure Planning formalized by the OEB in 2013[4]. The process identifies regional transmission and distribution needs and develops plans which recommend solutions for addressing those needs.

Types of Projects

Transmission projects typically fall in the following main categories. These projects, however, have decision points where the outcome will impact transmission losses. The influence that these decisions play in transmission projects will be reviewed as we progress through the following sections.

Customer Connection Projects

Transmitters are required to provide service to load points and access to the grid for generation interconnections. These projects establish the need. Like all projects, they are planned and assessed to provide the best connection at an optimal cost. All of these projects have direct connection components (e.g., the transmission connection from the grid to the point of interconnection [POI]). Other aspects of the project may be associated with reinforcing the grid in the area of the interconnection point (e.g., upgrading existing lines or adding lines to ensure the system meets all reliability criteria once the load or generation is connected).

Reliability Projects

Reliability needs are recognized through planning assessments or through the normal system operations performance of the grid. The IESO and most utility systems are operated on an N-1 or N-2 contingency basis. This means that the grid will remain within all reliability constraints when either one or two elements are lost, no assets are overloaded, and voltages are within acceptable limits.

Planning assessments will indicate if the grid will develop unacceptable voltages or thermal overloads with forecasted load growth. This behavior is recognized, and planning starts to evaluate different options to resolve the issue.

Economic Relief Projects

Economic relief projects are largely associated with congestion relief. Congestion constraints that cause less economical dispatch of generation can have significant financial impacts on customers and market participants.

Project Development and Selection

As the projects are identified to meet one of these three areas, different solution scenarios are proposed and evaluated. Since transmission grids are interactive dynamic systems, the issues and solutions are typically broader in impact than a direct one-on-one solution to issue. Rather issues affect regions, and solutions affect the characteristics of the grid over a broad region. Therefore many solutions have interrelated impacts on other grid operation characteristics. These impacts can be beyond the borders of a single transmission owner or even more owners.

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[4] https://www.oeb.ca/oeb/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

CIGRÉ Findings

CIGRÉ conducted several surveys of its members to assess various drivers for transmission investment. While not a direct survey for loss mitigation efforts, the results of the reports address the prioritization accorded by utilities to address various demands for capital investment for new construction and refurbishing existing assets; energy efficiency and mitigation of losses were among the drivers. The surveys included the following:

> *Life Cycle Assessment (LCA) of Overhead Lines TB265.* CIGRÉ WG B2.15. 2004.
>
> *Refurbishment Strategies Based on Life Cycle Cost and Technical Constraints TB448.* CIGRÉ WG B5.08. 2011.
>
> *Market Price Signals and Regulatory Frameworks for Coordination of Transmission Investments TB692.* CIGRÉ WG C5.18. 2017.
>
> *Review of Drivers for Transmission Investment Decisions TB701.* CIGRÉ WG C1.15. 2017.

The survey participants represented a broad range of committees and study groups constitutes within the utility industry, covering planning, design, operations, and regulatory and financial concerns.

The first survey concerning drivers for transmission investment, *TB701*, 24 respondents were received. 75% were TSOs from state ownership companies; however, of the six non-state respondents, four were TSO respondents from North America, Italy, Spain, and Great Britain.

Three significant drivers were stated for investment: security of supply, connections for demand and generation, and economically driven projects, in that order. Two main drivers were identified for refurbishments: end of useful life (50%) and upgrade of assets (35%).

Table 4-1 provides a summary of how the respondents attributed the various driving factors impacting their project identification and development. It is evident the development of projects and their selection for funding are driven by Long Term Integrated Strategic Basis. Reducing transmission losses is not a singular driving factor, but is embedded as part of the solutions' process for all categories.

Table 4-1
Summary of Percentage of Projects Impacted by External Factors[5]

Project Category	Environmental & Societal			Technical			Strategic / General Approach		
	Site or Route Access / Space	Local opposition / Concerns	Statutory / Planning Processes	Novel / Unconventional Transmission Tech.	Equipment / Tech. Obsolescence	Financial	Minimum Incremental Approach	Long Term Integrated Strategic Basis	Renewable Energy Related – State Policy
Security of Supply	46%	59%	56%	15%	8%	12%	7%	76%	20%
New Connection	50%	68%	58%	18%	5%	14%	7%	65%	40%
Generation Integration	35%	72%	62%	21%	4%	10%	7%	58%	55%
Economic	31%	47%	63%	22%	8%	15%	8%	80%	19%
Market Access	37%	37%	59%	41%	4%	15%	7%	81%	41%
Loop Flows	44%	50%	72%	8%	8%	0%	3%	81%	28%
Refurbishment	36%	57%	64%	21%	50%	7%	14%	36%	14%

Similarly CIGRÉ document, *TB692*[6], focuses on the changing environment that transmission systems must respond to today's unregulated industry. The diversity and granularity of generation sources entering the industry put a different light on the traditional electric delivery system. A new paradigm has arisen where the wires industry will serve as insurance to those depending on distributed generation as their primary source of energy, yet insist that the traditional wires business is ready and willing to provide the energy when the customer needs it with total transparency of the shift. The demand capacity required to support nominal load and the "insured load" must be provided by the wires delivery system. Continuing to support this demand on the transmission system is critical for the future and requires greater coordination during operations and efficiency from planning through operations. Conversely, systems will become less efficient as segments only serve as insurance for contingency loads or customer-choice load (fallback load). Caution must be exercised to avoid creating stranded investments that operate with minimal loading if any.

Furthermore, CIGRE's document, TB448[7], undertaken by CIGRE's Protection and Automation Study Committee addressed the refurbishment and end of life drivers. While the work was largely focused on station equipment used for protection systems, their strategies and application

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[5] *Review of Drivers for Transmission Investment Decisions TB701. CIGRÉ WG C1.15. 2017.*

[6] *Market Price Signals and Regulatory Frameworks for Coordination of Transmission Investments – TB692, CIGRÉ WG C5.18. 2017.*

[7] *Refurbishing Strategies Based on Life Cycle Cost and Technical Constraints – TB448*, CIGRÉ WG B5.08, 2011.

of life-cost analysis are fully applicable to the development of projects to address concerns with aging or degraded assets and when best to replace them.

Many utilities are facing end-of-life issues with many of their transmission assets. Infrastructure assets reach end-of-life levels due to age, environmental degradation, or obsolescence (e.g., parts are no longer available to repair and maintain older vintage equipment). The question of when to refurbish or replace equipment is a major consideration in planning budgets. The risk of failure or misoperation presents substantial liabilities to the utility and the public. Several sub-drivers in this arena affect the need and justification to replace an existing asset, including:

- Upgrades and expansions of facilities to accommodate load growth
- Obsolescence of equipment, including lack of spare parts, non-maintainable equipment, and inefficiency of operations
- Reliability and availability
- Excessive maintenance costs

The life-cost analysis is especially important in this evaluation because direct justification in a cost-benefit analysis seldom supports a decision to proceed. Rather incorporating all factors of risk, liability, maintenance, and efficiencies to be gained is required to fully justify proceeding to action. Loss mitigation costs and projected benefits are other facets that should be incorporated into these life-cycle studies.

US Department of Energy Policy and Systems Analysis

The U.S. Department of Energy (DOE) in the United States conducted a study into the opportunities for energy efficiencies in transmission and distribution systems[8]. The study's summary identified the advantages, drawbacks, key uncertainties, road blocks to application, and range of loss reduction for the same initiatives that we have identified throughout this report. The key drawbacks identified support the position that major policy changes and investment to the grid are required to reduce losses (e.g., reconductoring lines, replacing transformers, adding reactive power compensation, and FACTS equipment).

The constraint to accomplishing improvements is realizing a positive benefit-to-cost ratio for initiating the project on its incremental benefit. Once again, the long-term strategies incorporating loss mitigation strategies in the expansion, maintenance and refurbishment of the transmission grid are the best means to realize additional energy efficiencies.

Best Practices Summary

As part of this study, contact was made with several Independent System Operators (ISOs), including PJM, CAISO, SPP, ERCOT, MISO, NYISO, and ISO-New England. In addition, the project team also reviewed the ISOs' Planning Criteria and Guidelines, which are available on their websites. Transmission line losses, including station equipment, are not a substantive part

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[8] *Opportunities for Energy Efficiency Improvements in the U.S. Electricity Transmission and Distribution System*. Oak Ridge National Laboratory, Oak Ridge, TN: 2015.

of any documents. The same is applicable to the Planning Guides and Criteria used by the transmitters within these areas of grid operations.

A few guidelines indicate that loss mitigation benefits attributed to different project solutions may be included in the assessment of the best solution to propose for approval by the ISO and subsequently funded by the transmitter.

Loss mitigation is not used as justification for any project development or required for project evaluations.

Planning Summary on Loss Mitigation

The review of best practices applied across the industry, including international concerns, supports several clear points about the issues associated with incorporating loss mitigation efforts on transmission grids:

- Transmission grids seldom operate at near-capacity levels. The generation – transmission grid – load nodal system is designed for reliability and economic electric delivery with contingencies for the loss of one or many elements.
- The advent and expansion of distributed generation of many forms and sizes affect the transmission grid in ways that we are just beginning to experience and respond to.
- Loss mitigation projects are not self-supporting in that the projected loss savings do not exceed the cost of performing a mitigation project. As such projects with their primary objective being mitigation of transmission losses can seldom be justified based on lifetime savings alone.
- Loss mitigation costs and benefits should be considered in all project development and solution total cost analyses, such that the most cost-efficient solution is pursued that meets all reliability and safety criteria.

5
HYDRO ONE'S LOSS MITIGATION EFFORTS

This section discusses Hydro One's accomplishment in loss mitigation and the potential for additional future loss mitigation. It identifies accomplishments in line losses and station losses; reviews the utility's efforts at operating voltage adjustment; provides a listing of opportunities for Hydro One to mitigate losses; and presents the results of a sensitivity study of Hydro One data, which revealed the potential for future loss mitigation.

Hydro One Accomplishments

Network Characteristics/System Configuration/Network reinforcement

The IESO market rules define the voltage range for each voltage class. The Hydro One transmission network is operated at the upper end of the voltage range; the 230-kV system operates between 240 kV and 250 kV, and the 115-kV system between 121 kV and 127 kV. This helps to reduce losses.

For new projects, consideration is given to converting 115-kV areas to 230-kV supply. Two area supply projects in the Hydro One five year plan to meet capacity needs in the Barrie and Ottawa West areas involve conversion to 230kV supply. While the main reason for the both conversions is the inadequacy and cost of maintaining the existing 115kV supply, both projects also help reduce system losses. The Barrie area project converts an end-of-life 115-kV line and station to 230-kV facilities. The Ottawa West area project converts an existing 115-kV line to a 230-kV line to supply new load.

System reinforcement by building a new line or reconfiguring the system also helps reduce losses. The Southwest GTA Reinforcement project, provides for reinforcement of the existing supply by building a new double circuit 230kV line as the existing lines would be overloaded. The Aylmer-Tillsonburg Project provides for system reinforcement by reconfiguring the network and building a short section of line to provide dual supply to Tillsonburg TS. Capacitor banks will also be installed at Tillsonburg TS. Both projects reduce flows on the existing lines and help reduce losses.

Table 5-1 shows the loss mitigation projected through these three projects.

Table 5-1
Impact of Network Upgrades

Project	Reduction in Peak Losses (MW)	Estimated Annual Energy Savings (MWh)
Barrie Area Transmission Upgrade	0.6	2,238
South Nepean Transmission Reinforcement (Ottawa West)	0.7	1,202
Aylmer Tillsonburg Transmission Reinforcement	1.5	3,778
Southwest GTA Transmission Reinforcement	0.8	2,942

Lines and Station Equipment

Corona Losses

Hydro One has addressed the corona issue throughout its transmission design standards. Conductor diameter selection for high-voltage lines is made with corona mitigation as a parameter. In addition, all hardware assemblies are designed to mitigate corona by providing smooth edges and surfaces of hardware and incorporating appropriate corona and gradient rings to manage the electric field strength around the hardware assemblies.

Conductor Losses

Hydro One implicitly considers the impact of losses in all of its conductor selection for new projects and upgrades of existing lines.

For new projects, conductors are usually selected to satisfy the capacity requirements in the planning criteria based on forecast demand growth. Normally this approach results in the selection of a large conductor that has low losses. For line reconductoring projects, the conductor selection is limited by the existing tower structures. Hydro One has used ACSR TW (Aluminum Conductor Steel Reinforced Trapezoidal Wire) conductor on many projects. This conductor has lower resistance for the same diameter as the ACSR conductor and has lower losses.

Table 5-2 shows the loss mitigation projected through two of the upcoming projects involving line reconductoring.

Table 5-2 Impact of Reconductoring Adjustments

Project	Reduction in Peak Losses (MW)	Estimated Annual Energy Savings (MWh)
Manby TS to Wiltshire TS Conductor Upgrade	0.9	3,615
M30A/M31A Conductor Upgrade	1.4	3,167

Transformer Losses

Hydro One addresses transformer losses in several ways. First, during procurement, each transformer's design and performance are evaluated per requirements and criteria in the purchase specification. HO requires the transformers to be designed to minimize losses at load and while unloaded. Second, overall transformer losses are reduced as transformers of older and less efficient designs at existing stations are replaced with newer more efficient designs due to end-of-life or load growth considerations. This is a gradual and long-term strategy given the economic impact and timing of the replacements.

Samples of the loss mitigation estimates for two transformers that were replaced on the Hydro One system are shown later in the Sensitivity Study and Appendix A.

Summary of Current Practice and Opportunities

As the study has shown, the majority of loss mitigation tasks must be resolved during the development of different project solutions to the mandated generation and load interconnections, regulatory, and reliability projects. Reduction in transmission losses is considered at the planning level as one of many priorities that the IESO and Hydro One must balance. Economic impact assessments of losses are conducted when such losses could reasonably be consequential to the selection of a least cost plan.

Energy efficiency projects do not justify their funding solely based on improving the socio-economic-environmental issues that efficiency can derive. However, Hydro One already addresses many of the identified means to mitigate losses in their current practices listed in Table 5-3. Hydro One practice is summarized in Table 5-3below.

Table 5-3 Summary of Hydro One Practices

Methods Under Consideration	HO Current Practice
Raising Nominal Voltage	Due to expense, voltage upgrades are driven more by reliability and adequacy concerns. Will continue to evaluate conversion of 115kV systems to 230kV operation for cost effectiveness and reduction of losses.
Optimization of Voltage Profile	System is already operating close to equipment limits.
Use Lower Loss Conductors	Currently use ACSR or compact ACSR TW conductors for capacity needs. Consider use of larger size conductors which have lower resistance, where cost effective, in the future. Hydro One does not use ACCC conductors because of poor performance under ice loading conditions.
Re-direct Power Flows	Power flow at any given time is dependent on the connected load and generation. Losses are a factor considered in the overall optimization of the generation dispatch by the IESO.
Bundle Conductor Optimization	Use bundled conductors for 500 kV
Improve Corona Losses	Insulator Hardware systems have been designed to eliminate corona. Conductor sizes also selected to avoid corona.

Shieldwire Segmentation	Not used due to high tower ground potential rise.
Improve Insulation Losses	Considered during insulation coordination design of insulator assemblies and structure configurations.
Installation of Low Loss Transformers	Purchase specifications include cost of losses and vendor transformer designs and quotations are assessed based on lowest lifetime costs including the cost of losses.
Convert to DC, Bipole or Tripole	Currently there are no HVDC systems in the province.
Switch off Equipment Not in Use	Not used due to safety and reliability concerns. Uncertainty as to the availability of equipment when it is required to be back in-service.

Sensitivity Study

Hydro One provided loading information and conductor and transformer characteristics for nine transmission lines and two load transformers to allow the performance of a sensitivity analysis to see how much loss mitigation could potentially be achieved on a sample of Hydro One assets. The sensitivity study is further described in Appendix A.

The power flow data was provided in the format of the hourly average line flow or transformer loading for the assets for every hour in 2016. One of the significant aspects of the loading data is the fact that the assets were loaded much less than their full thermal capacity. Table 5-4 shows that only three of the lines are loaded over 30% above average. .

Table 5-4 Sample Line Descriptions and Annual Load Factor

Line #	Voltage (kV)	Section Length (km)	Conductor Size	Conductor Material	Conductor Stranding	Conductors Per Bundle	Average Loadflow
1	230	7.3	1780.0 (kcmil)	ACSR	59/19	1	38%
2	500	208.7	585.0 (kcmil)	ACSR	26/7	4	19%
3	115	6.9	605.0 (kcmil)	ACSR	54/7	1	39%
4	115	40.0	336.4 (kcmil)	ACSR	26/7	1	23%
5	230	12.1	1192.5 (kcmil)	ACSR	54/19	1	13%
6	230	12.0	1192.5 (kcmil)	ACSR	54/19	1	31%
7	230	168.3	795.0 (kcmil)	ACSR	26/7	1	11%
8	230	116.8	795.0 (kcmil)	ACSR	26/7	1	24%
9	230	30.4	795.0 (kcmil)	ACSR	26/7	1	14%

This is not an indication that Hydro One is underutilizing its assets. Rather it is proof that the way transmission grids are operated per NERC requirements of meeting N-1 contingency criteria means many assets are lightly loaded, supporting the heavier loaded assets for occasions when they fail or are take on outage for maintenance. In addition, economic dispatch of generation to meet loads on the system governs line loading.

In the case of the two transformers, Table 5-5, you see that they are more heavily loaded, but again, on average, only 60%.

Table 5-5 Sample Transformer Descriptions and Annual Load Factor

Asset	Voltages (kV)	Average Loadflow
50 MVA	121/28	60%
75 MVA	244/44	60%

Using the provided power flows, calculations of the estimated losses were made for every hour using the asset characteristics (e.g., resistance-impedance) for the existing conductor or transformer and the more efficient lower resistance conductor or transformer.

Hourly plots throughout the year were made to visualize the potential loss mitigation. The first frame in Figure 5-1 is for Line 1 and is similar to most of the line plots. The second frame in Figure 5-1 is for the 500 kV line, where loading levels averaged just under 20% for 2016. In both cases there is a marginal difference between the losses calculated for the in-service conductor versus the more efficient conductor for the loading profiles of Hydro One.

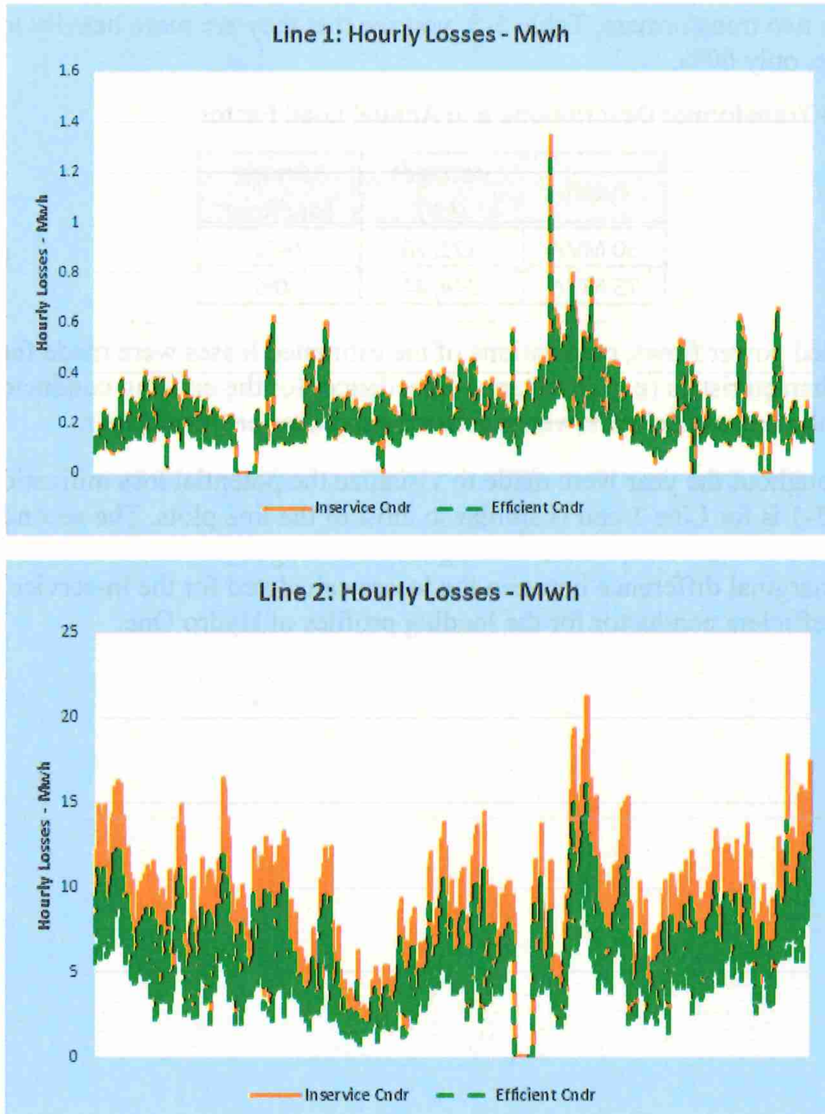

Figure 5-1
Sample Plots for Transmission Lines

Hourly plots throughout the year were also made to visualize the potential loss mitigation for the two transformers. The results are shown in Figure 5-2. The constant No-load losses are shown in each frame for the in-service unit and a potentially more efficient design transformer of the same size. The hourly tracking data represents total losses (i.e., No-load plus the losses from power flow).

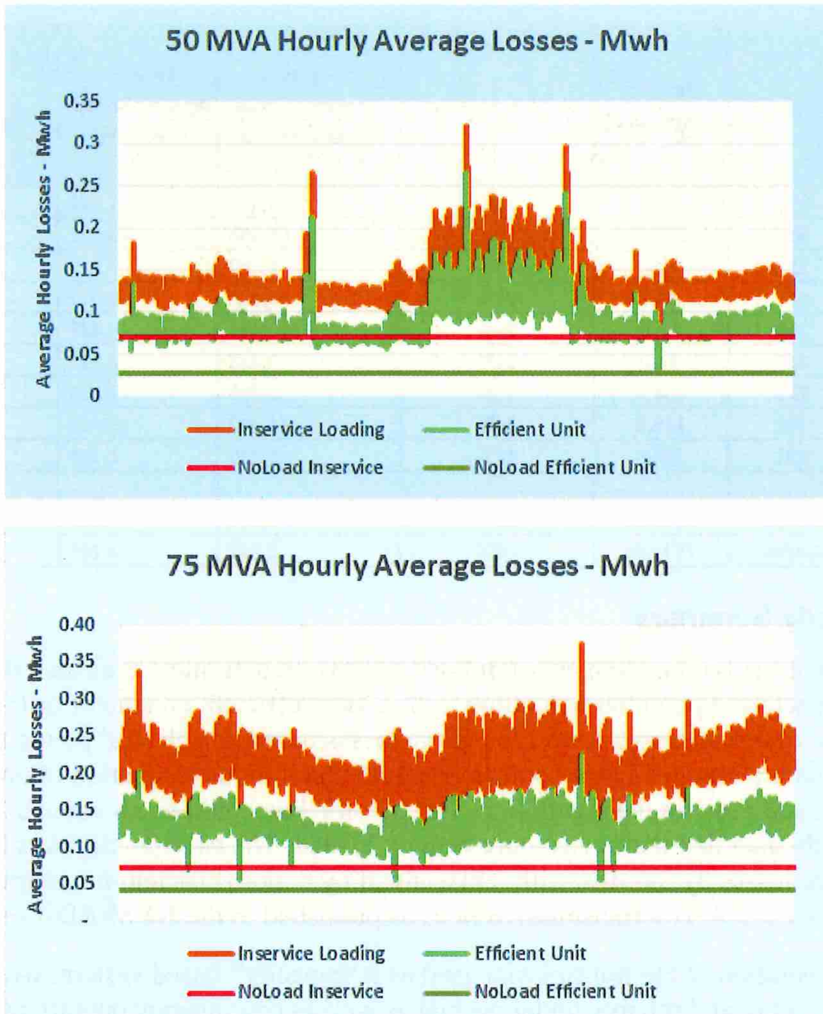

Figure 5-2
Sample Loss Plots for Transformers

Newer transformers offer more benefits as they are more efficient with lower losses than older units. However, replacement costs are high and transformer replacement is not undertaken for loss mitigation alone.

Table 5-6 summarizes the results of the loss mitigation comparison. For the transmission lines, the potential benefits of reconductoring existing lines are limited. The loss mitigation percentage is not significant, and it would not offset the costs to install the replacement conductor. This example validates why line loss mitigation projects are not self-justifying themselves.

Newer transformers offer more benefits as they are more efficient with lower losses than older units. However, replacement costs are high and transformer replacement is not undertaken for loss mitigation alone.

Table 5-6
Loss Mitigation Potential

Asset	Voltage (kV)	Section Length (km)	Average Loadflow	In-service Approx Annual Losses (Mwh)	Efficient Approx Annual Losses (Mwh)	% Loss Reduction
1	230	7.3	38%	1,987	1,922	3%
2	500	208.7	19%	63,185	48,772	23%
3	115	6.9	39%	1,567	1,510	4%
4	115	40.0	23%	3,000	2,617	13%
5	230	12.1	13%	451	428	5%
6	230	12.0	31%	2,438	2,311	5%
7	230	168.3	11%	3,785	3,589	5%
8	230	116.8	24%	14,442	13,752	5%
9	230	30.4	14%	1,225	1,161	5%
50 MVA	121/28	50 MVA	60%	1,230	815	34%
75 MVA	244/44	75 MVA	60%	1,887	1,134	40%

Sensitivity Study Summary

The sensitivity analysis on nine transmission lines and two transformers indicated the following potential loss impacts and potential reductions with a more efficient conductor or transformer design. The lines' effective losses were 11% of the losses based on full load power flow. Reconductoring with a more efficient conductor would result in loss reduction of only 3-5% for seven of the lines and 13% on the eighth line. The 500-kV line could reach about a 23% reduction due to the fact that the line is more heavily loaded. The two transformers have the potential to reduce losses by 34-40% with replacement by a more efficient transformer. Losses in general amount to 1.5-5.8% on transmission lines as published in the NYSERDA report[9].

The design and operation of the transmission grid as a "capacity"-based system, with adequate capacity to serve safely and reliably under normal as well as contingency operations due to loss of one or more elements, cause many transmission assets to operate normally in ranges of 30-50% of their full rated capacity. The cushion of capacity is needed to meet reliability criteria when system models indicate the capacity is needed for contingencies. The fact that assets operate at lower load factors also greatly reduces the impact of potential losses due to full capacity levels.

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[9] *Assessment of Transmission and Distribution Losses in New York*, EPRI, Palo Alto, CA: 2012. PID071178 (NYSERDA 15464).

6 CONCLUSIONS

Hydro One requested EPRI's support in preparing a comprehensive assessment of current best practices in the industry relative to the mitigation of transmission losses for line and station equipment. This report addresses how losses are realized during the operation of the transmission grid and various mitigation techniques that can be applied to reduce losses. More importantly, the study investigated the current industry best practices relative to how transmission system providers, independent system operators, and regulatory bodies are addressing the loss mitigation concern.

Conclusions

The investigation in best practices showed these key points:

1. Transmission losses are not avoidable.
2. Losses can be mitigated to a limited extent with appropriate application of design.
3. Transmission losses and their mitigation are not a focal point of transmitters, their independent system operators, or their regulatory bodies. At best, a few entities include the impact on losses that various design options may have in the selection of their project solutions.
4. Transmission grids seldom operate at near-capacity levels. The generation – transmission grid – load network system is designed for reliability and economic electric delivery with contingencies for the loss of one or many elements.
5. Transmission Projects are initiated based on system need to ensure adequacy and reliability of supply or provide supply to customers. No utility is pursuing loss mitigation projects solely based on the potential mitigated loss savings over the life cycle of the asset.

Hydro One design practices are materially consistent with industry best practices for loss mitigation.

7
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A
APPENDIX A

Loss Calculations for Sample Hydro One Data

Hydro One supplied loading data for nine transmission lines and two transformers. With the data provided, the project team could calculate estimates of the losses incurred throughout the year and make a comparison to an alternative conductor or transformer design that is more efficient from a losses perspective. A range of line lengths, voltage classes and conductor sizes was provided as shown in Table A-1. Of particular note is the average power flows for the lines. All lines are loaded at 40% or lower capacity typical of transmission networks.

Table A-1
Sample Transmission Line Descriptions

Line #	Voltage (kV)	Section Length (km)	Conductor Size	Conductor Material	Conductor Stranding	Conductors Per Bundle	Average Loadflow
1	230	7.3	1780.0 (kcmil)	ACSR	59/19	1	38%
2	500	208.7	585.0 (kcmil)	ACSR	26/7	4	19%
3	115	6.9	605.0 (kcmil)	ACSR	54/7	1	39%
4	115	40.0	336.4 (kcmil)	ACSR	26/7	1	23%
5	230	12.1	1192.5 (kcmil)	ACSR	54/19	1	13%
6	230	12.0	1192.5 (kcmil)	ACSR	54/19	1	31%
7	230	168.3	795.0 (kcmil)	ACSR	26/7	1	11%
8	230	116.8	795.0 (kcmil)	ACSR	26/7	1	24%
9	230	30.4	795.0 (kcmil)	ACSR	26/7	1	14%

The in-service conductors are ACSR (Aluminum Conductor Steel Reinforced), which have a steel core strand. The steel stranding increases the conductor's resistance and thus losses. The ACCC (Aluminum Conductor Composite Core) has a composite core rather than a steel core and has trapezoidal-shaped aluminum strands that allow for a greater area of aluminum for the same overall conductor diameter; both characteristics provide lower losses... Figure A-1shows a side-by-side cross-section view of the ACSR (left) and ACCC (right). The aluminum strands are the same electrical grade aluminum. The cores are different: galvanized steel versus a carbon-composite matrix core.

Figure A-1
Cross Sections: ACSR and ACCC

The following sets of charts for each line, Figure A-2 to Figure A-10, identify the power flow in a histogram showing loading level frequency on the vertical axis. Note that, all of the loadings are skewed to lower load factors, in quantity and level.

The second frame shows the hourly loading as a load factor, % of line capacity, during the course of the year. Finally, each line has a plot of the line losses calculated for the in-service conductor and an appropriate more efficient alternative, ACCC conductor. Note how seldom, the load factors peak and how short the peak loadings are throughout the year.

Table A-2 contains a comparison of the line losses for the in-service conductor and a more efficient alternative.

Similar data was provided for two transformers on the Hydro One system for analysis—a 50 MVA and a 75 MVA transformer. Hourly average loading was provided, as well as the No-load and Loaded losses measured at manufacture by the vendor (Figure A-11 and Figure A-12).

The 50-MVA unit shows a slightly skewed lower loading histogram, while the 75-MVA unit shows a near normal distribution. Both units averaged a 60% load factor for the year.

The third plot in the two sets provides a plot of the losses estimated for each unit using the hourly average loading values. For a transformer, there are No-load losses associated with just energizing the unit and the eddy current hysteresis in the coils. That value remains constant while the unit is energized. In this case, the in-service units had 71- and 72-kW losses for the 50- and 75-MVA units, respectively. When the units carry load, they incur additional joule heating losses, and those losses follow the loading pattern. In plot three of the two sets, the loss curves, other than the No-load, contain the sum of the Load-loss and No-load losses.

In comparison, Hydro One supplied transformer characteristics for replacement transformers that would be purchased according to their new specifications that require improved efficiency by the transformer vendors. The No-load loss levels are considerably lower, 27 and 43 kW for the 50- and 75-MVA units, respectively.

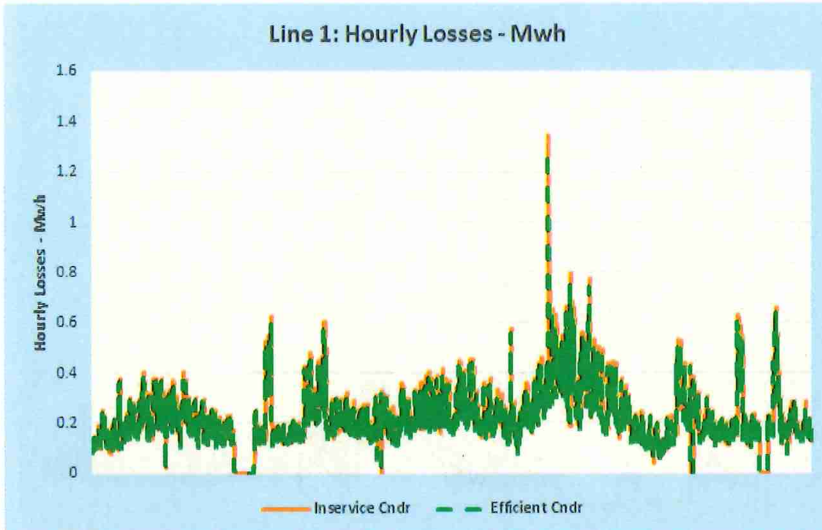

Figure A-2
Line 1 Loading and Loss Comparison

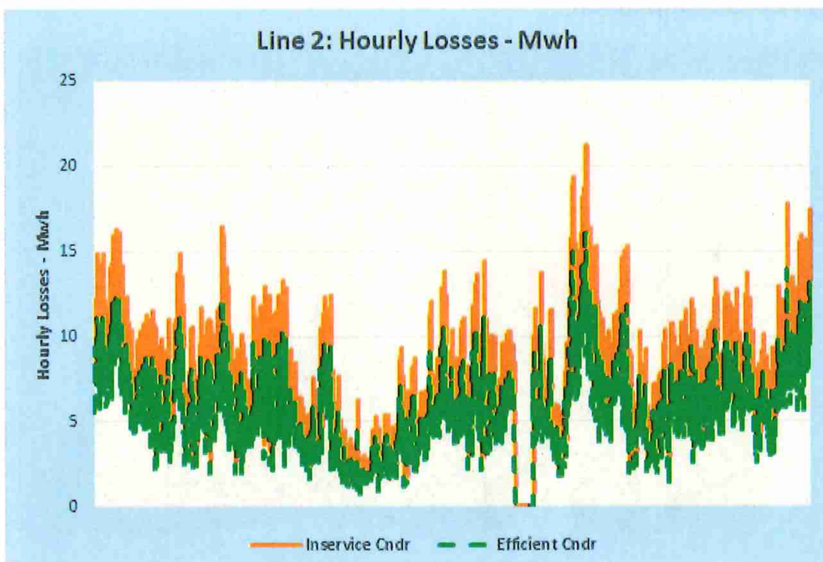

Figure A-3
Line 2 Loading and Loss Comparison

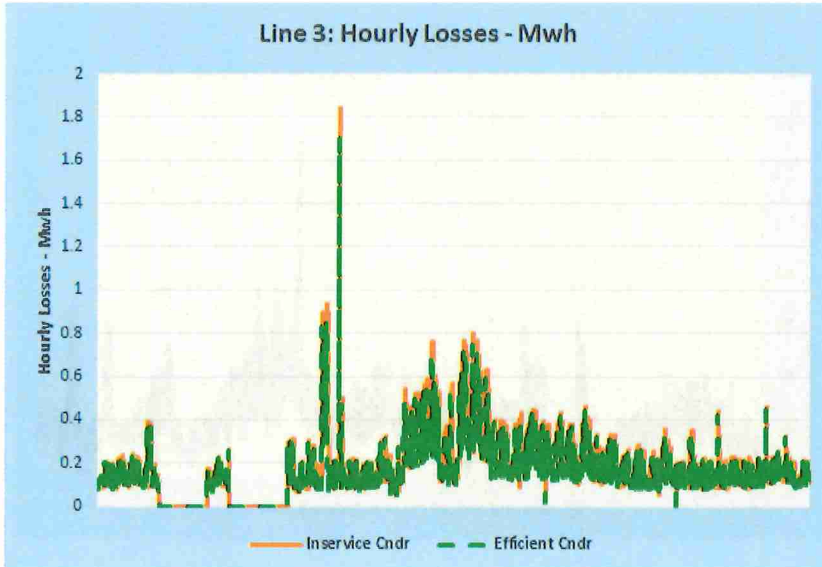

Figure A-4
Line 3 Loading and Loss Comparison

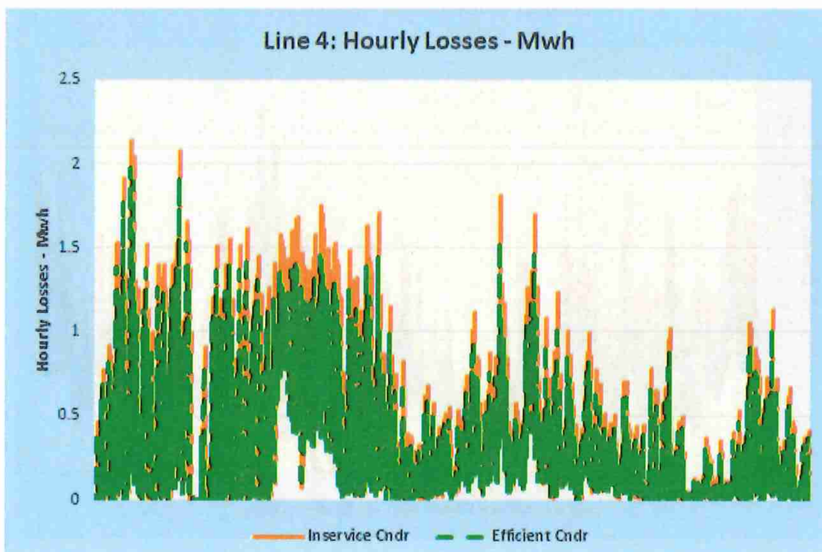

Figure A-5
Line 4 Loading and Loss Comparison

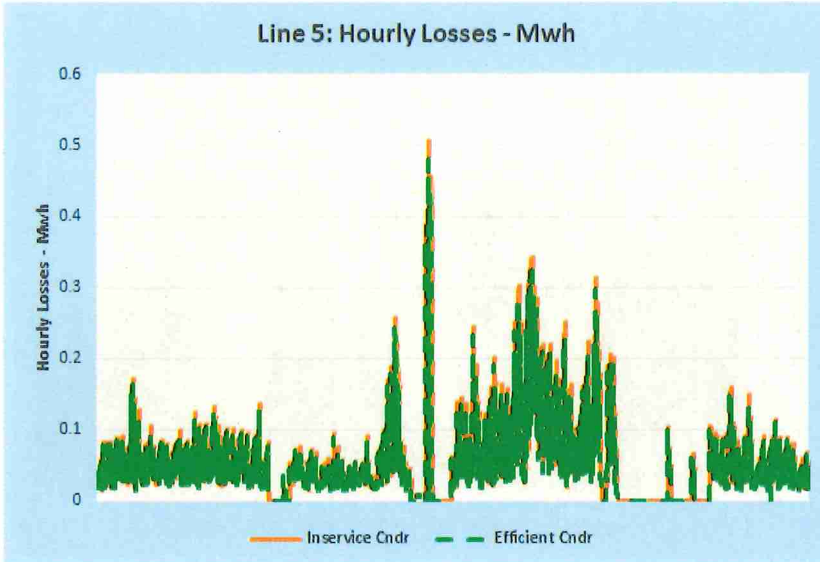

Figure A-6
Line 5 Loading and Loss Comparison

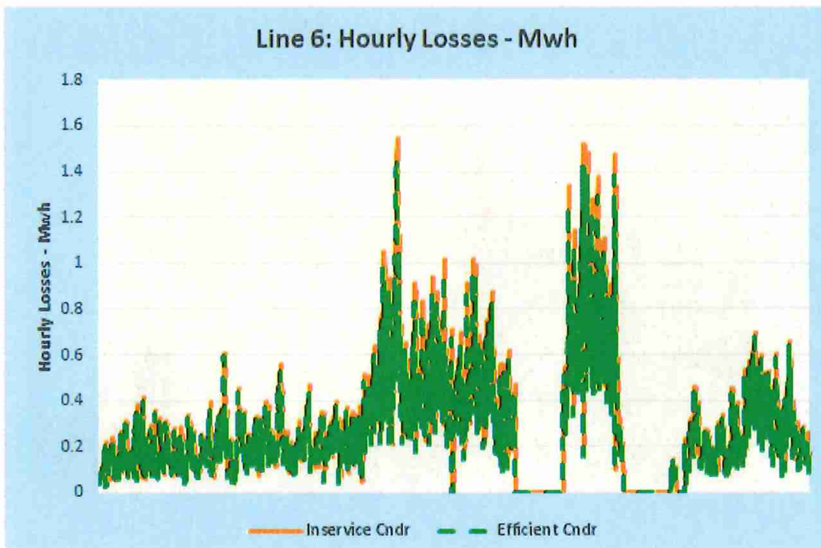

Figure A-7
Line 6 Loading and Loss Comparison

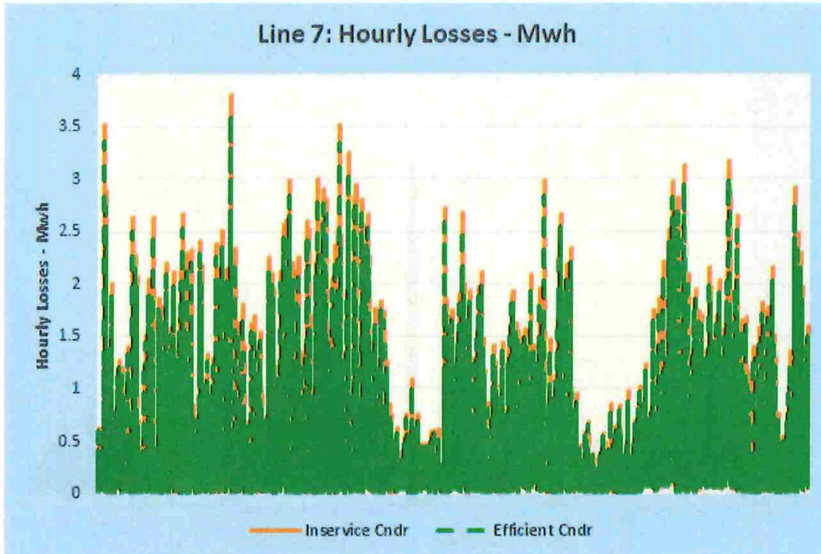

Figure A-8
Line 7 Loading and Loss Comparison

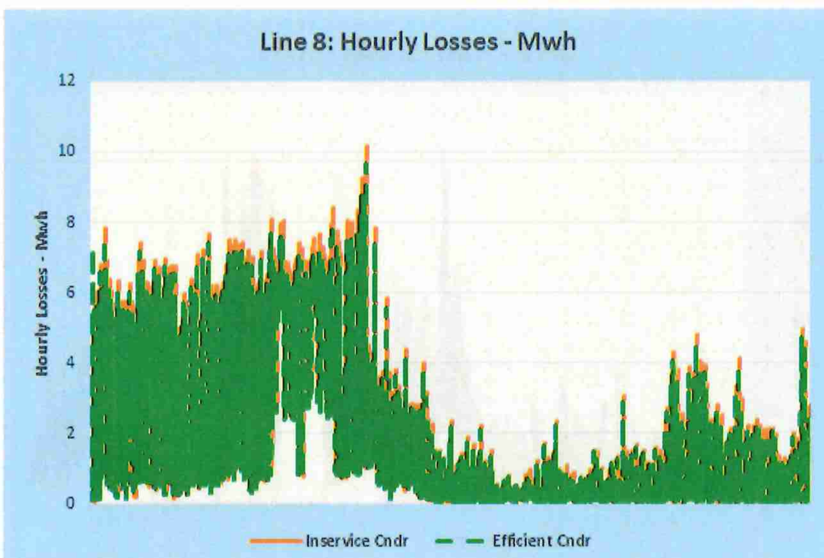

Figure A-9
Line 8 Loading and Loss Comparison

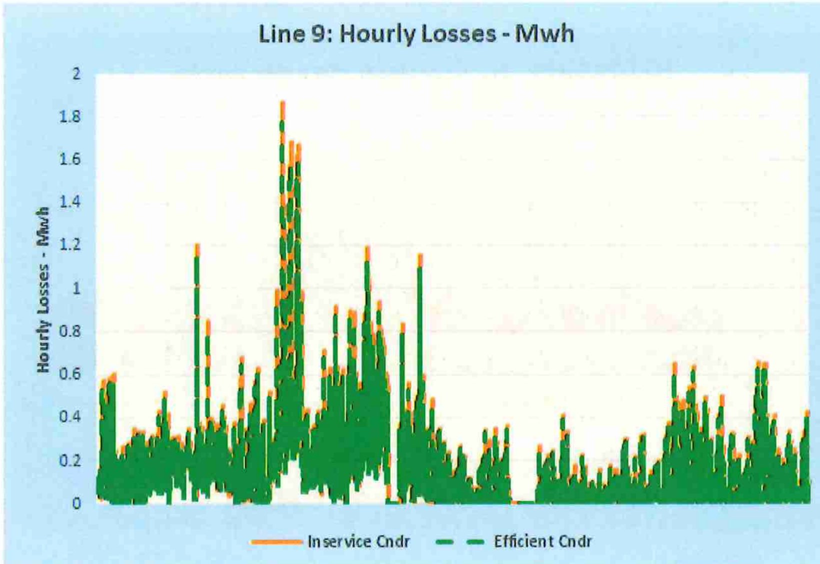

Figure A-10
Line 9 Loading and Loss Comparison

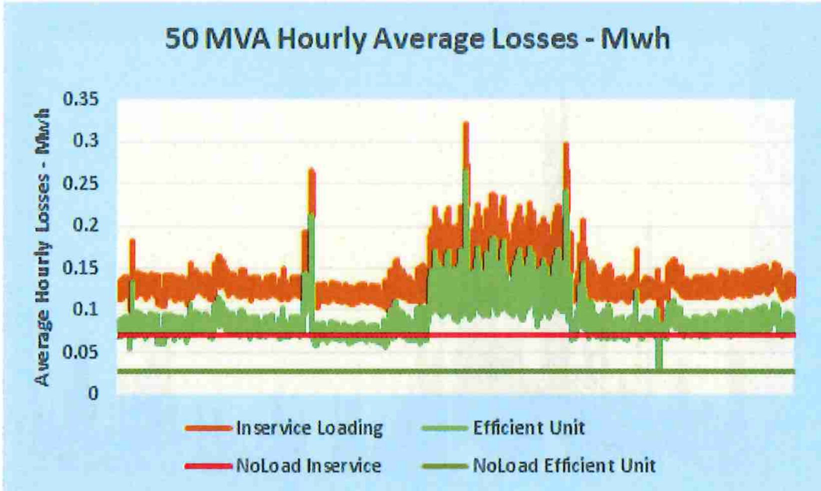

Figure A-11
50 MVA Transformer Loading and Loss Comparison

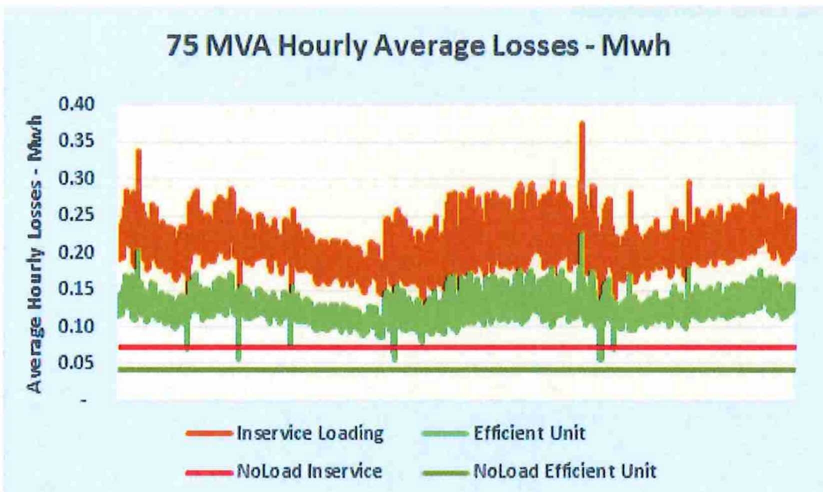

Figure A-12
75 MVA Transformer Loading and Loss Comparison

Loss Calculation Comparison

Based on the analysis and comparison for the transmission lines and transformers, the comparative losses and reductions are shown in Table A-2. Only two of the transmission lines showed significant savings from using a more efficient conductor to reduce losses. The other seven lines ranged from a 3 to 5% reduction. The analysis of the two transformers showed that more efficient transformer designs available on the market today efficiently reduce losses by 30-40%.

Table A-2

Loss Comparison Results

Asset	Voltage (kV)	Section Length (km)	Average Loadflow	In-service Approx Annual Losses (Mwh)	Efficient Approx Annual Losses (Mwh)	% Loss Reduction
1	230	7.3	38%	1,987	1,922	3%
2	500	208.7	19%	63,185	48,772	23%
3	115	6.9	39%	1,567	1,510	4%
4	115	40.0	23%	3,000	2,617	13%
5	230	12.1	13%	451	428	5%
6	230	12.0	31%	2,438	2,311	5%
7	230	168.3	11%	3,785	3,589	5%
8	230	116.8	24%	14,442	13,752	5%
9	230	30.4	14%	1,225	1,161	5%
50 MVA	121/28	50 MVA	60%	1,230	815	34%
75 MVA	244/44	75 MVA	60%	1,887	1,134	40%

The line losses estimated from the loading information provided by Hydro One are a very small portion of the losses if estimated based on the rating of the transmission element. This is especially true in the case of the line losses.

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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

2.0 (5.3.1 A) ASSET MANAGEMENT PROCESS

Hydro One's asset management goal is to identify and prioritize capital investments and asset maintenance throughout the life cycle of its assets. To achieve this goal, Hydro One undertakes a strategic and methodical asset management process, drawing upon the company's extensive expertise and experience in a variety of disciplines (including management, financial, economic, engineering, and operations) to monitor its transmission system assets, identify and define needs, and determine the optimal timing for investment and maintenance activities. In doing so, Hydro One strives to ensure that it delivers, and can continue to deliver over the long-term, a level of transmission service that is responsive to identified customer needs and preferences, as well as operational needs, while also mitigating rate impacts and risks in support of the company's strategic objectives.

Section 2 of the TSP focuses on the process Hydro One uses to manage its transmission assets. The overall process includes two main components: (i) the Asset Needs Assessment, during which Hydro One undertakes extensive and detailed technical reviews of its assets to identify a portfolio of investment candidates; and (ii) the Investment Planning process, during which the investment candidates are scored, prioritized, reviewed and developed into a capital investment plan in alignment with intended outcomes based on corporate objectives, asset needs, regulatory requirements, investment risks, customer preferences, and other identified constraints.

For greater clarity, the Asset Needs Assessment (including the resulting candidate investment portfolio) can be thought of as a major input into the Investment Planning process. As such, under Section 2.1, Asset Needs Assessment is presented not as a separate stand-alone process, but as one of the crucial inputs that inform the full strategic planning context underlying the Investment Planning process.

Section 2 of the TSP consists of the following sections:

Section 2.1 - Investment Planning Process

For the planning of capital investments, Hydro One utilizes a comprehensive Investment Planning process for the identification and prioritization of capital investments. As noted above, the Investment Planning process is informed and underpinned by the relevant planning context, which necessarily includes the results of Hydro One's Asset Needs Assessment, as well as other factors such as customer preferences, economic assumptions, load forecast, and system needs. Section 2.1 provides a detailed discussion of the planning process.

Section 2.2 – Asset Component Information

Hydro One's transmission system consists of a number of key components that must all work effectively in order to deliver reliable service. Section 2.2 provides details on each of the key asset components, including their purpose, condition and outlook.

Section 2.3 – Asset Life Cycle Optimization

Hydro One develops and implements asset strategies for various components of the transmission system based on their characteristics and associated business requirements. Section 2.3 describes the asset strategy for key components and outlines the specific maintenance and replacement strategies for each asset type with a view to optimizing the total lifecycle cost of the asset.

2.1 (5.3.1, 5.4.2) INVESTMENT PLANNING PROCESS

2.1.1 (5.3.1) INTRODUCTION

Asset Management is the combination of management, financial, economic, engineering, and other practices applied to physical assets, with the objective of providing a level of service that is consistent with customer needs and preferences, consistent with asset needs and responsive to rate impacts. Hydro One's asset management goal is to monitor system assets and determine the optimal timing of asset maintenance and capital investments throughout the asset life cycle. This is done to manage risks and to support the achievement of Hydro One's business objectives and outcomes, while managing total cost and customer rate impacts.

Hydro One uses a comprehensive and robust Investment Planning process to identify, prioritize and optimize investments to manage costs, asset/system operational risks, customer needs and preferences, customer rate impacts, and achieve the company's business objectives and outcomes.

Hydro One has recently revised and implemented an improved eight-step risk-based investment planning process to identify, prioritize and optimize investments set out in Hydro One's Transmission System Plan ("TSP").

Hydro One continues to make improvements to its risk-based Investment Planning process by incorporating feedback received, implementing leading industry practices and responding to concerns raised during the prior rate proceedings. The improved investment planning process is designed to provide a consistent understanding of risks to enable Hydro One to cost effectively deliver the highest value investments and service for its customers. This process allows candidate investments to be consistently assessed and prioritized based on the level of risk mitigated and the cost and value delivered toward achieving business objectives.

The overall Investment Planning process is set out below in Figure 1**.**

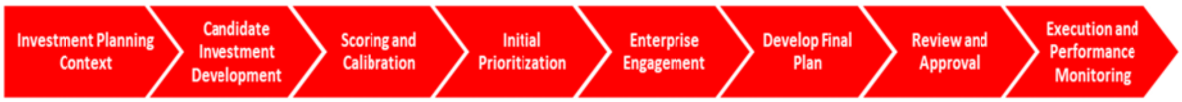

Figure 1 – Improved Eight-Step Investment Planning Process

Key improvements to Hydro One's investment planning process include the use of:

- Revised risk assessment framework to provide consistent risk assessment of safety, reliability and environmental risks;
- Clear definitions of risk impacts to enable consistent assessments across investments and calibration sessions to calibrate and align risk assessment practices; and
- Challenge sessions to engage stakeholders across the organization to review the investments and discuss potential trade-offs.

Hydro One management at all levels, including the Executive Leadership Team ("ELT"), are involved in the investment planning process to develop an investment plan that achieves the overall corporate strategy, efficiently mitigates risks, and delivers value to customers.

The Investment Planning process generates an annual budget for Operations, Maintenance and Administration ("OM&A") and capital work programs, and a six-year planning forecast that allows Hydro One to meet the OEB's filing requirements. The 2020-2024 Investment Plan presented in this TSP is a product of the improved investment planning process.

The sections below detail each step of Hydro One's improved Investment Planning process and provide the rationale and benefits of the specific process improvements that have been implemented.

2.1.2 (5.3.1) INVESTMENT PLANNING CONTEXT

Figure 2 - Investment Planning Context

As shown above in Figure 2, Hydro One's Investment Plan is primarily guided by: (i) the company's strategic vision and objectives; (ii) planning economic assumptions (e.g., economic assumptions, load forecast, etc.); (iii) customer engagement feedback; and (iv) asset/system needs, customer needs and preferences.

2.1.2.1 (5.3.1 A) STRATEGIC CONTEXT

Hydro One used its strategic priorities and objectives to develop its TSP. These priorities and objectives are presented in Figure 3 below.

Strategic Priorities

- **Employees**
  - Maintain a safe and inclusive workplace for all employees
  - Foster a high level of employee engagement throughout Hydro One through a new engagement approach focused on developing company –wide action plans ("Time for Action")
- **Customer Experience**
  - Deliver industry-leading customer service, in response to identified customer preferences
  - Foster innovation in the business to adapt to changing customer requirements and market opportunities
  - Advance reconciliation and work proactively to build relationships with Indigenous peoples and communities based on understanding, respect and mutual trust
- **Operational Effectiveness**
  - Invest in grid infrastructure and grid modernization to deliver a high level of reliability and quality to our customers
  - Focus on continuous improvement in productivity and operating efficiency to maintain lowest possible costs
- **Government and Regulatory Relationships**
  - Maintain and build constructive, transparent relationships with governments and regulatory entities in all jurisdictions where we operate
  - Deliver on obligations mandated by government through legislation and regulatory requirements
- **Financial Strength**
  - Maintain a strong balance sheet to support continuing investment in our business
  - Invest in assets to better serve customers

SAFETY COMES FIRST | STAND FOR PEOPLE | EMPOWERED TO ACT | OPTIMISM CHARGES US | WIN AS ONE

Figure 3 – Hydro One's Strategic Priorities and Objectives

As part of its Renewed Regulatory Framework ("RRF"), the OEB introduced the following four outcomes:

- **Customer Focus** – services are provided in a manner that responds to identified needs and customer preferences;
- **Operational Effectiveness** – continuous improvement in productivity and cost performance is achieved; and transmitters deliver on system reliability and quality objectives;
- **Public Policy Responsiveness** – transmitters deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

- **Financial Performance –** Financial viability is maintained; and savings from operational effectiveness are sustainable.

In managing its transmission assets that are critical to customers and Ontario's economy, Hydro One is committed to meet the RRF outcomes and has integrated them into its improved Investment Planning process. Figure 4 below demonstrates the close alignment of Hydro One's business objectives to the RRF outcomes.

Customer Focus	**Customer Satisfaction**	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes
Operational Effectiveness	**Cost Control**	• Actively control and lower costs through OM&A and capital efficiencies
	Safety	• Drive towards achieving an injury-free workplace
	Employee Engagement	• Achieve and maintain employee engagement
	System Reliability	• Provide top quartile reliability relative to transmission peers
Public Policy Responsiveness	**Public Policy Responsiveness**	• Ensure compliance with all codes, standards and regulations • Partner in the economic success of Ontario
	Environment	• Sustainably manage our environmental footprint
Financial Performance	**Financial Performance**	• Achieve the ROE allowed by the OEB

Figure 4 - Hydro One's Business Objectives

Guided by Hydro One's strategic priorities and objectives Hydro One evaluates its assets and other needs to inform and guide the development of its investment candidates. For example, the RRF outcomes corresponding to the relevant transmission objectives are measured by a set of risk-based taxonomies and qualitative flags which form the criteria against which candidate investments are evaluated, risk mitigation is quantified, and trade-offs between investments are made in the prioritization and optimization of the investment plan. These are further described below.

Consistent with the recommendations included in the Investment Planning process benchmarking report, provided in Attachment 14 of Section 1.4 of the TSP, Hydro One implements a strategic allocation process at the onset of its planning cycle. This process step divides the plan into smaller, discrete allocations, which provides the framework for subsequent investment prioritization and optimization. Through this process, Hydro One's corporate strategy and objectives are translated into key outcomes, and the level of funding required to achieve those objectives is defined. Specific business unit capital and

OM&A allocations are subsequently defined strategically based on customer, operational, public policy and financial outcomes and funding level necessary to meet its objectives.

The basis for this upfront allocation is the expenditure level included in the prior year's plan, adjusted for efficiency gains and new strategic directions as presented in Figure 5 below. The overall investment envelope and year-over-year pacing of investments is also informed by the feedback received through the customer engagement process.

Figure 5 - Upfront Allocation Setting Framework

As noted in TSP Section 1.3, through the customer engagement survey, respondents were provided with descriptions of four illustrative investment scenarios (Scenarios A, B, C, D), and provided a line of data points that started at zero and extended beyond the four of the illustrative investment scenarios. Customers were asked to select any point along that continuum that reflected what they believed to be the best and most appropriate balance between rate impacts and outcomes. Scenario C, which maintains the level of investment proposed in the previous application, improves long-term reliability performance and offers level future rate increases, was strongly favored over the other three scenarios. Customer preference for long-term reliability performance with level future rate increases is reflected in the initial funding envelope, which was subsequently divided into smaller, more discrete allocations.

This new process step enabled Hydro One to directly link the investment planning process with the corporate strategy and provided an opportunity to incorporate executive level inputs early in the process. It also provided clarity and direction to the planning process stakeholders with regards to investment allocations and targeted outcomes. This process step was initiated in early 2018 and finalized prior to the calibration session.

In parallel with the allocation setting process, Hydro One held a formal risk assessment workshop to identify risks in achieving its business objectives, including asset management and maintenance, extreme natural events and climate change, resource adequacy performance and the changing resource mix. Based on the initially identified list of risks, Hydro One developed candidate investments to address these risks. Throughout the planning process, Hydro One monitored and tracked the funding status of these investments.

2.1.2.2 (5.3.1 B) PLANNING ASSUMPTIONS

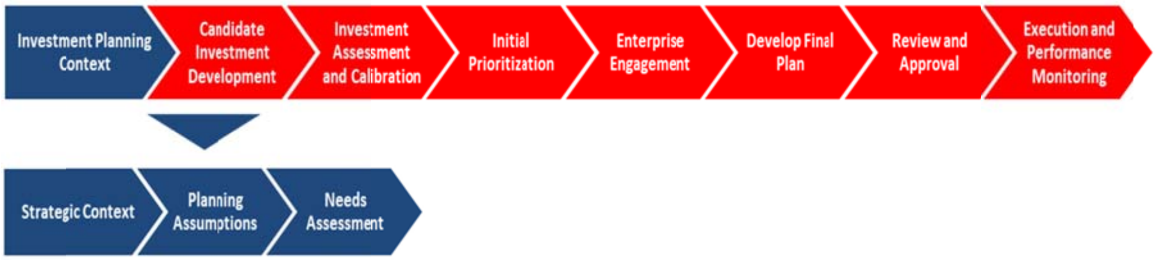

Figure 6 – Investment Planning Context – Planning Assumptions

To facilitate the preparation of its Investment Plan, Hydro One compiled an economic outlook forecasting customer load and key economic statistics as shown in Figure 6 above.

A (5.3.1 B) LOAD FORECAST

Hydro One uses various methods, such as econometric models, end-use models, and customer forecast surveys to produce the load forecasts that are required for its transmission business and that inform investment needs. A detailed description of Hydro One's forecasting methodology, models and their elements is included in Exhibit E, Tab 3, Schedule 1.

The system forecast for the period 2020 to 2022 has been prepared in accordance with the OEB-approved forecasting methodology, which is summarized in Table 1 below.

Table 1– Forecast of Transmission Charge Determinants (12-month average peak in MW)

Year	Network	Change (%)	Line Connection	Change (%)	Transformation Connection	Change (%)
2020	19,604	0.0	19,071	0.0	16,252	0.0
2021	19,469	-0.7	18,941	-0.7	16,142	-0.7
2022	19,322	-0.8	18,800	-0.7	16,021	-0.7

The decrease in load over the test period is primarily attributable to conservation and demand management activities and economic conditions. At the same time, pockets of load growth are expected across Hydro One’s transmission service territory due to urban and industrial/mining developments. Further details on the areas experiencing local load growth are provided in the various Regional Planning reports attached to TSP Section 1.2.

B (5.3.1 B) ECONOMIC ASSUMPTIONS

Consumer Price Index

Hydro One, as an Ontario based transmitter, has relied on the Ontario Consumer Price Index (“CPI”) for its assumptions about inflation. The CPI provides a broad measure of the cost of living. CPI reflects the change in retail price of a representative shopping basket of about 600 goods and services from an average household’s expenditure: food, housing, transportation, furniture, clothing, and recreation.

Table 2 – Ontario CPI (%)*

	Historical Years					**Bridge Year**	**Forecast Period**				
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CPI-Ontario	2.3	1.2	1.8	1.7	2.4	1.8	2.0	1.9	2.0	2.0	2.0

** Source: IHS Global Insight's November 2018 forecast.*

Exchange Rates (CDN:USD)

The exchange rate figures and forecasts for 2019 to 2022 are based on the November 2018 edition of the Global Insight Forecast. These exchange rates, as presented in Table 3 below, are used to forecast other variables such as fleet vehicle related costs, which are typically obtained in US dollars.

Table 3 – Exchange Rate *

USD:CAD	Historical Years					Bridge Year	Forecast Period				
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Exchange Rate	0.905	0.783	0.755	0.771	0.775	0.782	0.793	0.797	0.799	0.800	0.803

** Source: IHS Global Insight's November 2018 forecast.*

2.1.2.3 (5.3.1 B) NEEDS ASSESSMENT

Figure 7 - Investment Planning Context – Needs Assessment

As shown in Figure 7 above, Hydro One performs a needs assessment to identify the drivers in the development of candidate investments and collect the data necessary to enable the assessment of risks and subsequent calibration process. The needs assessment identifies (i) asset needs, (ii) customer needs and preferences, (iii) system needs (including regional planning considerations), and (iv) other external influences. The needs assessment also identifies potential hazards, vulnerabilities, threats or other risk sources that could present risks to achieving Hydro One's business objectives.

A ASSET NEEDS ASSESSMENT

A detailed and systematic assessment of asset-specific investment needs is an essential prerequisite of, and critical input into, the Investment Planning process that underpins this TSP. The output of the Asset Needs Assessment is a portfolio of investment candidates which reflects the asset-related needs and risks (particularly on the basis of asset condition) to be further evaluated against the relevant planning context. The investment candidates are further scored and prioritized through Hydro One's Investment Planning process (as described in TSP Section 2.1.4 below) to achieve the optimal balance of risk and benefits.

Hydro One performs a continuous asset risk assessment ("ARA") process to determine individual asset needs which rely on asset condition data, engineering analysis and other information including the input of experienced planning professionals. The ARA is primarily concerned with the major equipment groups (e.g. transformers, conductors, breakers, and protection and control systems) that directly affect system reliability.

One of the inputs into the ARA is a quantitative asset analytics system, which combines information from various Hydro One databases to provide an initial common understanding of asset health. This process drives efficiency and effective planning decisions by ensuring a consistent view of asset information for all planners. As part of the preliminary risk assessment, asset analytics enables the review and consolidation of a variety of information from enterprise reporting systems, such as condition information driven by deficiency and preventive maintenance reports, demographic information including make, model, and type, criticality to the transmission system, performance data based on equipment outages, utilization information, and economics. While not a determinative driver in the ARA process, asset analytics is one useful tool that aids Hydro One planners in identifying asset risks for further screening and confirmation. Hydro One's planners also take into account additional factors such as load forecasts, equipment ratings, operating restrictions, security incidents, environmental risks and requirements, compliance obligations, equipment defects, obsolescence, and health and safety considerations to ensure capital expenditures target the most appropriate mix of assets. As part of the ARA process, transmission assets are evaluated on the following six risk factors:

- **Condition** - Risk related to the increased probability of failure that assets experience when their condition degrades over time. Asset condition is defined using different criteria, depending on the asset. For example, the condition of a transmission station transformer is measured by visual inspections and analysis of the oil within the transformer. The condition of a wood pole is measured by a visual inspection, a sounding test, and if required, a boring test. While methods to evaluate condition vary from asset type to asset type, the condition of all assets of a given type is evaluated consistently. Assets of a given type that have a relatively high condition risk are candidates for refurbishment or replacement.
- **Demographics** - Risk related to the increased probability of failure exhibited by assets of a particular make, manufacturer, and/or vintage. Typically, the probability of asset failure increases with age. Thus, the asset demographic risk increases as an asset ages. Assets with relatively high demographic risk are candidates for refurbishment or replacement.
- **Criticality** - Represents the impact that the failure of a specific asset would have on the transmission system. Primarily, it is used to show relative importance of an asset compared to other assets of the same type. Assets whose failure would result in an interruption to a larger amount of load would have an asset criticality that is higher than assets whose failure would have a smaller impact on the system load. Asset criticality is used to prioritize the refurbishment or replacement of assets whose condition, demographic, performance, utilization or economic risk has already resulted in the asset being considered a candidate for refurbishment or replacement.
- **Performance** - Risk that reflects the historical performance of an asset, derived from the frequency and duration of outages. Past performance can be a good indicator of expected future performance. Therefore, assets with a relatively high-performance risk can be considered candidates for refurbishment or replacement.
- **Utilization** - Risk that reflects the increased rate of deterioration exhibited by an asset that is highly utilized. The relative deterioration of some assets is highly

dependent on the loading placed upon them or the number of operations they experience. For example, transformers that are heavily loaded relative to their nameplate rating deteriorate more quickly than those that are lightly loaded. Similarly, circuit breakers utilized for capacitor and reactor switching which are subject to significant operations experience accelerated mechanical and electrical wear-out of the breaker. Therefore, the asset utilization risk for transformers and circuit breakers attempts to consider their relative deterioration based on available loading and operational history, respectively.

- **Economics** - Risk based on the economic evaluation of the ongoing costs associated with the operation of an asset. Depending on the asset type, this evaluation may be as simple as determining the replacement cost of the asset, or as complex as comparing the present value of ongoing maintenance to that of complete refurbishment or replacement. While an economic evaluation can identify assets that are candidates for replacement, more typically, the evaluation assists in selecting the best form of remediation for assets already deemed to be candidates for refurbishment or replacement.

It is important to recognize that although asset analytics aids in the identification of asset needs as an initial step, it is not the sole input or driver of the ARA. Hydro One planners take into account a range of other considerations and data sources, as informed by sound engineering oversight and experience-based decision making, in the initial determination of asset needs, which are then ultimately verified against asset condition assessments.

Throughout the assessment of individual asset needs, Hydro One's planners carry out a process of grouping identified needs into logical, functional and geographic groups. For example, a customer need for increased capacity and an asset need to replace transmission station equipment, such as a transformer or switchgear, might be grouped together if the same transmission station is involved. Through this process, diverse individual needs are brought together to form potential projects or programs that may be brought forward as candidate investments. These groupings of potential candidate investments are then scoped and defined based on an identified asset needs, customer feedback and other inputs. Once grouped, Hydro One undertakes a further validation process to confirm that the need for the project or program remains, has not evolved and will not be addressed by any other means.

Hydro One planners conduct on-site assessments with field personnel to validate and confirm asset condition and related information identified through enterprise reporting systems and asset analytics. For instance, planners speak with personnel who manage and maintain the equipment on a daily basis and solicit first-hand insight regarding deficiencies or potential upgrades which may be required. For high-value assets, such as transformers, subject matter experts perform a thorough assessment of asset condition and consider and advise on issues such as equipment obsolescence, manufacturer support, and “repair vs. replace” evaluations. All transformer replacements are reviewed by subject matter experts who prepare Transformer Assessment Reports that are used to justify investment decisions. The detailed asset assessment and field review, inspection and validation are invaluable tools for ensuring that the identified needs actually reflect the condition of assets in the field and relevant operating information including the concerns of field personnel, which could not otherwise be verified through asset analytics alone.

The outputs of the ARA process are potential candidate investments that are put forth for further consideration during the Investment Planning process that have been evaluated and justified on the six risk factors described above. For detailed information on asset condition, demographics and performance for Hydro One’s four major asset categories please refer to TSP Section 2.2.

ARAs establish the necessary fact base to later assess the probability and consequence of safety, reliability and environmental risks at the scoring stage of the Investment Planning process. Risks relating to asset condition, demographics, performance and utilization directly inform the probability score, and risks relating to asset criticality directly inform the consequence score. As discussed in TSP Section 2.1.4 below, the probability and consequence scores are then converted into risk scores which inform the initial prioritization and optimization.

Asset Management of Stations vs. Lines

While the above described process generally applies across transmission asset types, it is important to note that Hydro One tailors the specific approach according to the characteristics of each major transmission asset class – stations and lines.

For station assets, Hydro One has established a seven to ten-year assessment cycle that enables all necessary renewal work to be performed at each of the 294 transmission stations during the cycle. This assessment process is carried out by experienced planning professionals where information is aggregated from customers, enterprise reporting systems, field personnel, and asset specific subject matter experts to develop a comprehensive assessment report of current asset condition. This ensures that asset needs at all stations are reviewed on a recurring basis, which may or may not result in the need for an investment as per the ARA process described above. This is a planning level assessment which is used to inform the development of candidate investments that are an input to the Investment Planning process and complements the planned inspections, maintenance and testing performed on the assets as discussed in TSP Section 2.3. Rather than making numerous return visits to the same stations to repair or replace different types of assets, requiring multiple outages, Hydro One has adopted an integrated approach whereby assets requiring replacement at a station are bundled together (based on key station assets) and executed at once. The candidate investments identified through the Asset Management process include station-specific integrated investments that have been developed in accordance with the established assessment cycle.

Hydro One’s approach to asset management for its transmission line assets is shaped by the nature of the specific line assets and their typical service lives. For example, the expected service life for overhead transmission conductors is 90 years, though the conductor may reach end of life before or after that time depending on the specific environmental circumstances. When a conductor fails or has been determined to have reached end of life based on its condition, as confirmed by testing, replacement is the only solution. When the conductor needs replacement, this creates a rare opportunity in the asset lifecycle for Hydro One to implement a full line refurbishment of the relevant segment in order to bring the associated assets (i.e., poles, parts of steel structures, foundations and the conductors) to a condition that is as close to new as possible. Other transmission line components (e.g., wood poles, shield wire, aviation lighting and U-bolts) do not last this long and as such are subject to separate, recurring asset replacement programs. Regardless of the type of transmission line asset, Hydro One will not replace assets unless their condition warrants the replacement.

B CUSTOMER NEEDS

Hydro One believes that understanding its customers, and their needs, is critical to its business. Hydro One engages with customers proactively and regularly through various mechanisms. Customer needs can be categorized as either (i) initial connection needs, or (ii) needs of connected customers. Initial connection needs are generally identified either by a direct customer connection request through the Hydro One customer connection process or by need assessments and customer consultations as part of the Regional Planning process. Once connected, customer needs are identified by continuous monitoring of the power system and engagement with transmission customers.

C CUSTOMER ENGAGEMENT

Hydro One’s senior management team has renewed the company’s focus on customer relationships. As described in TSP Section 1.3, in addition to regular customer engagement, Hydro One commissioned Innovative Research Group (“Innovative”) to conduct a customer engagement survey (the "Customer Survey") with 156 transmission customers in May and June 2017. The results of this survey have been used as an input to this TSP.

Through its customer engagement efforts, Hydro One learned the following:

- Safety, reliability, and environment are among the top prioritized outcomes;
- Customers' reliability requirements differ. While some process-oriented industrial customers may prefer reducing the frequency of outages over duration, non-industrial customers may prefer multiple shorter duration outages;
- All customer segments prefer the even pacing of investments over time to achieve a gradual and uniform impact on rates; and
- When presented with several investment scenarios, the majority of customers preferred investment levels in line with the investment plan that was before the OEB in the prior transmission proceeding by at least a three to one margin. It is seen as reflective of the current approach which has served the system well, and a less risky option.

In developing the improved taxonomies **(**as explained in TSP Section 2.1.4 below), Hydro One considered specific customer feedback and added outage frequency to the probability framework to incorporate specific feedback from customers. Over 80% of customers surveyed identified safety, reliability, or environmental considerations as high priority items (seven or higher on a scale of ten). The details of how Hydro One incorporated customers' feedback into its investment plan are included in TSP Sections 2.1.4 and 3.2.1.3.

D SYSTEM NEEDS

System needs cover work necessary to ensure that the transmission system is maintained and operated to provide an adequate and reliable supply to customers. They are driven by the requirement to meet current and forecast load demand resulting from the connection of new load customers and generation facilities. System needs include:

- Provision of adequate transmission capacity to reliably deliver electricity to the local areas connected to Hydro One's transmission system;
- Provision of inter-area network transfer capability to enable electricity delivery from areas with sources of supply to load centers across the system;
- Provision of necessary protection and control modifications to Hydro One's transmission stations to address the impacts of distribution connected generation;
- Implementing the necessary mitigation measures to minimize high-impact risk (e.g., installing special protection systems to protect equipment from overload conditions; uprating of station short circuit capacity) and to ensure the safe, secure and reliable operation of Hydro One's transmission system in accordance with the IESO's Market Rules, OEB's Transmission System Code, and other mandatory industry standards such as those established by the North American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating Council ("NPCC"); and
- Provision of power quality data collection capabilities and pilot cost effective mitigation measures to address specific issues faced by Hydro One customers.

Under the electricity industry structure in Ontario, the need for new transmission system facilities or system enhancements may be identified by Hydro One Transmission, the IESO, the Government of Ontario (e.g. through the Long Term Energy Plan referenced in TSP Section 1.7), or customers. These needs are identified and assessed by Hydro One Transmission in conjunction with customers, the IESO and LDCs under the regional planning process as outlined in TSP Section 1.2 or by the IESO as part of the planning for the bulk electric system.

E EXTERNAL AND OTHER INFLUENCES

Hydro One also uses information on industry best practices, trends and benchmarking to compare its operations and performance to other utilities within the industry. Technical studies performed on the transmission system with the support of the Electric Power Research Institute or other industry partners provide further insight into the state of the asset base and support the decisions regarding which assets are candidates for investment. A description of the benchmarking studies and the resulting recommendations are included in TSP Section 1.4.

2.1.3 (5.3.1 B) CANDIDATE INVESTMENT DEVELOPMENT

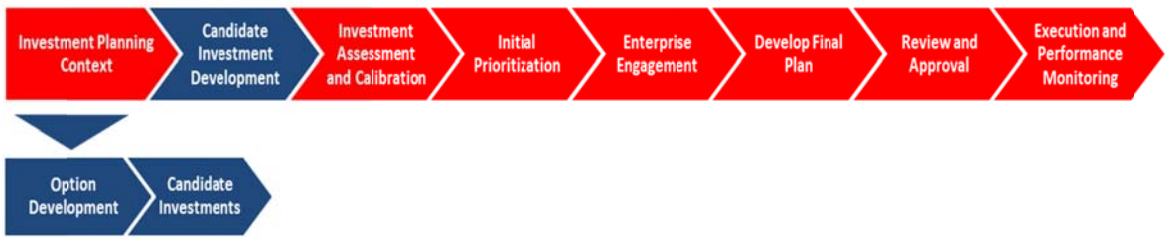

Figure 8 - Candidate Investment Development

Based on the asset needs identified through the ARA process (as discussed in TSP Section 2.1.2.3), Hydro One planners develop a set of candidate investments that are likely to address the relevant asset needs and risks as shown in Figure 8 above. These candidate investments are then evaluated for inclusion in the Investment Plan.

While the candidate investments arising from the ARA process primarily pertain to System Renewal investments, there are other types of investment candidates that are not necessarily asset condition triggered, and these are discussed in the following section.

2.1.3.1 OPTION DEVELOPMENT

To become a candidate for consideration, a proposed investment must demonstrate a need, reflect appropriate planning assumptions, and be supported by unbiased information to enable credible evaluation.

2.1.3.2 INVESTMENT CATEGORIES

Proposed investments are classified into one of the four OEB investment categories: System Renewal, System Access, System Service, and General Plant.

A SYSTEM RENEWAL

System Renewal investments aim to extend the expected service life of transmission assets through replacement and/or refurbishment, thereby minimizing life cycle costs and maintaining reliability performance.

Identifying and selecting System Renewal investments involves several steps. The first step is to consolidate the asset needs in the ARA by major asset type. The next step is to identify options to mitigate risk for assets that are deemed to have a significant increased risk of failure. In doing so, Hydro One relies upon multiple factors used to evaluate failure risk, including condition, criticality, performance, and demographics as described in TSP Section 2.1.2. Hydro One then performs a detailed review of the asset needs to determine if there are opportunities for an integrated approach for stations or lines investment. Where practical, Hydro One examines alternative levels of investment and their corresponding level of risk to which it might be exposed. Finally, the preferred option to mitigate the risk is selected through the "Scoring and calibration" step described in TSP Section 2.1.4.

B SYSTEM ACCESS

System Access investments are non-discretionary investments driven by mandated service obligations to connect customers in accordance with Hydro One's Transmission Licence. They include provision of new customer connections or modification of existing customer connections. System Access investments fall into the following three categories: load customer connections, generator customer connections, and third-party transmission.

Load Customer Connections

Load Connection investments are initiated based on customers' requirements for capacity and reliability improvements or identified by the regional planning process as documented in TSP Section 1.2. The investments cover provision of new or modified transformation connection facilities, including new feeder positions at existing transformer stations, or construction of new connection lines and stations.

In accordance with the Transmission System Code, a customer has discretion as to whether a new load connection will be provided by the customer or by Hydro One. If requested, Hydro One is required under the Transmission System Code and its Transmission License to provide new line connection and/or transformation connection facilities.

For investments identified as part of the regional planning process, the need and timing are outlined in the Regional Infrastructure Plan report prepared by Hydro One in conjunction with all regional LDCs and the IESO.

The costs of the load connection investment are the responsibility of the benefiting customer(s) and the costs are fully recovered from these customers via incremental connection revenues and/or capital contribution as per a Connection Cost Recovery Agreement ("CCRA"), the calculation of which is based on Hydro One's Connection Procedures.

Generator Customer Connections

Generation connection investments are based solely on customer requests. In most cases, the generation investments have been triggered as a result of provincial government policy under which the IESO has initiated procurement of renewable, clean and/or high efficiency energy. The needs are typically addressed by radial connection facilities. However, in some cases, other modifications (such as enhancements to protection systems, voltage or reactive power support, and/or breaker and station upgrades to address increased short circuit levels) may be required to Hydro One's local area connection or network facilities in order to reliably integrate new generation into the system. In accordance with Section 6.3.4 of the Transmission System Code, modifications to connection facilities associated with generation connection are fully recovered from the generators via capital contribution as per a Connection Cost Recovery Agreement ("CCRA"), the calculation of which is based on Hydro One's Connection Procedures. Any incurred investment in network facilities is recoverable as specified in Section 6.3.5 of the Transmission System Code.

Third-Party Transmission

In certain circumstances, Hydro One is mandated to complete investments due to the actions of third parties such as governmental bodies and transit organizations. These investments are usually fully-funded by the third party. In rare cases, they may fall under a provincial statute that allows for cost sharing. They are included in the plan as a cost placeholder calculated on the basis of historical data.

C SYSTEM SERVICE

System Service investments address the need for modifications to the transmission system to ensure it continues to meet operational objectives while also addressing anticipated future customer electricity requirements through:

- increasing the inter-area transfer capability between generation areas and load centres within Ontario and/or with neighbouring utilities;
- addressing anticipated future load requirements in local areas where existing transmission facilities have reached capacity; or
- satisfying system operational objectives (e.g., local area supply adequacy; acceptable voltages; operation of equipment within the ratings; system stability; and/or operating flexibility).

System Service investments typically affect many customers over a significant period of time.

System Service investments are identified and developed as part of regional planning and/or the IESO bulk planning studies. The scope of System Service investments can range from installation of special protection systems or capacitor banks to maximize the use of existing facilities (in order to defer the need for a major investment) to major transmission expansion projects. Major transmission expansion projects may include construction of new transmission lines into the area, and/or new or additional 500/230kV or 230/115kV autotransformer capacity. These major projects typically require long lead-times, particularly if there are statutory or regulatory approval requirements under the *Environmental Assessment Act* or Section 92 of the *Ontario Energy Board Act (1998)*.

Line loss mitigation investments fall under this category. In the EB-2016-0160 Decision, the OEB found that Hydro One should work jointly with the IESO to explore cost effective opportunities for line loss reduction. In response, Hydro One has worked with the IESO and initiated an independent third party review by EPRI of Hydro One’s current practice along with the industry best practices. At the conclusion of its analysis, EPRI confirmed that Hydro One’s current design practices are consistent with these best practices for loss mitigation. Further details are provided in TSP Section 1.8.

D GENERAL PLANT

General Plant investments are comprised of modifications or replacements to assets that are not directly or specifically part of the transmission system. These may include investments related to Hydro One’s transport and work equipment fleet, facilities, and information technology. The process to identify and select investments in each of these areas is discussed below.

Transport and Work Equipment Fleet

Transport and work equipment investments ensure that crews have the ability and the vehicles required to access and perform the work required. Investments are primarily replacements of existing equipment. Hydro One identifies and selects the investments on the basis of need, which is driven by the following key factors:

- work program requirements;
- staffing requirements;
- industry standards (manufacturer's recommendations) for life cycle expectancy; and
- operating cost drivers.

Based on this information, a preferred alternative is recommended in line with Hydro One's expected business plan and work programs.

Facilities

Facility investments are necessary to provide appropriate and adequate accommodations for core work programs and changing requirements of the various lines of business. The investments are identified and selected based on need which is driven by the following key factors:

- aging facilities that are confirmed to be at or near their end of life;
- compliance with legal requirements, such as the *Accessibility for Ontarians with Disabilities Act*;
- expanding work programs;
- evolving work practices;
- improved health and safety;
- improved security;
- sustainable development; and
- work efficiency and productivity.

Based on the information gathered, Hydro One undertakes a comparative evaluation of alternatives, which may include the lease or purchase of existing or green-field developments against status quo condition. A preferred alternative is recommended based on the objective to pursue the most cost-effective strategy that addresses operational requirements and manages risk.

Information Technology

Information Technology ("IT") investments are identified and selected based on the need to address:

- potential end of life IT systems and the optimal point in time to initiate their upgrade or replacement;
- changing business needs;
- existing or new business processes; and
- mandatory regulatory or compliance changes to systems as and when required, (e.g., security, policy changes).

2.1.3.3 CANDIDATE INVESTMENTS

The final step before determining the portfolio of candidate investments is to further screen and validate the needs that triggered the identified investments:

1. Grouping the identified needs into logical, functional, and geographic groups. For example, a customer need for increased capacity and an asset need to replace transmission station equipment, such as a transformer or switchgear, could be grouped together if the same physical assets are involved.
2. Scoping investments appropriately based on asset need and customer feedback. Condition remains the primary driver for all asset replacement decisions. At the same time, Hydro One planners engage with customers (e.g., LDCs, transmission connected industrial customers) to solicit feedback regarding the planned station work, including any operational or performance concerns and whether the identified investment can feasibly address the identified needs and preferences. For instance, in respect of each planned transformer replacement, Hydro One interfaces with

customers, including the relevant LDCs to identify the need for building in capacity flexibility for purposes of accommodating future load growth.

3. Validating that the investment need still exists, that the need has not evolved, and that the need will not be addressed by other means. For instance, a planned new station may eliminate the need to replace and reconfigure an end-of-life station asset and could also provide the additional capacity required by customer.

Once it has been determined that a proposed investment meets a relevant need, planners prepare a high-level scope and preliminary estimate of cost and pacing so it can be considered for inclusion in the Investment Plan.

2.1.4 (5.3.1 B) INVESTMENT ASSESSMENT AND CALIBRATION

Figure 9 – Investment Assessment and Calibration

The “Investment Assessment and Calibration” step refers to the process by which Hydro One assesses the potential investment options it has identified as shown in Figure 12 above. It involves the following activities:

- Assessing the risk mitigation impact of investment candidates developed in the previous step of the planning process;
- Assessing the impact of investment candidates on desired outcomes; and
- Calibrating risk assessments to enable consistent assessments across investments.

Hydro One continuously improves its risk assessment process.[1] Since the last transmission rate application, Hydro One has introduced a more rigorous and transparent process that includes the use of:

- Revised risk assessment framework to provide consistent risk assessment of safety, reliability and environmental risks;
- Clear definitions of risk impacts to enable consistent assessments across investments and calibration sessions to calibrate and align risk assessment practices; and

[1] See Appendix 1 for a summary of improvements made to Hydro One’s Investment Planning process.

- Challenge sessions to engage stakeholders across the organization to review the investments and discuss potential trade-offs.

The improved risk assessment process relies primarily on three risk taxonomies that have been developed to classify safety, reliability and environmental risks. The taxonomies provide guidelines for planners to assess the consequence and probability of existing operational risks and the residual risks remaining based on how investment projects are expected to mitigate those risks. The taxonomies are fact-based, with significant analytical rigor behind the development of different levels of classification. For example, different levels of safety consequence are based on historical data of safety outcomes derived from utility industry experience. Reliability consequence information is based on realistic customer outcomes for escalating levels of consequence based on Hydro One's experience.

Hydro One's improved risk assessment method enables it to incorporate key customer and regulatory outcomes into its evaluation of projects in two ways. The first is through the definitions of consequence in the risk taxonomies, and the second is through the flagging system (described in more detail below). Hydro One's risk taxonomies are based on key outcomes (safety, reliability, and environment)[2] that customers and the OEB have identified as high priority. These outcomes are reflective of top customer priorities identified through Hydro One's customer engagement, detailed in TSP Section 1.3, and align with key regulatory and policy concerns (e.g., reducing GHG emissions, ensuring public safety). Through multi-level, executive reviews, Hydro One continuously monitors the alignment of investment drivers with identified customer needs and preferences.

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[2] Reliability consequences can be classified in terms of unsupplied energy, load impacted and minutes of interruption duration. Environmental consequences can be classified in terms of overall impact to the environment, oil spill severity and greenhouse gas emissions. Safety consequences can be classified in terms of harm to employees or the public.

The improved risk assessment process is conducted in the following six steps.

1. **Understand the primary purpose of the candidate investment:** Identify the primary objective of the investment and the risks addressed (safety, reliability or environmental).
2. **Define worst reasonable direct impact ("WRDI"):** Identify the worst reasonable direct outcome of not making the investment and, if available, the additional costs associated with such an event occurring.
3. **Determine the consequence of the baseline risk:** Establish the consequence of the WRDI in the event the investment is not completed, using the updated risk-based framework.
4. **Determine the probability of the baseline event:** If no investment occurs, evaluate the consequence and probability of the WRDI occurring using the risk-based framework.
5. **Determine the residual consequence and probability:** Determine the consequence and probability of the WRDI occurring even if the investment is made.
6. **Calculate the final mitigated risk score:** Determine the final mitigated risk score based on the difference in baseline and residual risk score for each of the three risk areas (safety, reliability, and environment).

The WRDI is determined by examining what a reasonably undesirable outcome might be as a direct result of not making the investment (e.g., failure event that is the most reasonable, additional cost/risk of repair during emergency compared to regular operation). Determination of a "reasonable" outcome is based on an assessment of expectation based on: (i) historical events, (ii) unique characteristics of the proposed investment, and (iii) confidence in the outcome occurring. Determination of what a "direct" outcome is based on an assessment of whether the event/damage is an immediate result of the failure itself, or it is a secondary/coincidental result.

2.1.4.1 INVESTMENT ASSESSMENT

As described above, Hydro One assesses each proposed investment on the consequence and probability of the safety, reliability and environmental risks that they are designed to mitigate. The three risk taxonomies measure the probability and impact of specific risks and are comparable across investment types and sources of risk. These taxonomies were developed in an iterative and collaborative process based on: (i) historical data from Hydro One and other utilities, (ii) economic impact studies (e.g. insurance tables), (iii) management insights, and (iv) customer feedback (e.g., outage frequency was added to the probability framework to incorporate specific feedback from customers).

Each risk taxonomy has seven consequence levels upon which each investment is assessed. The seven consequence levels are based on the financial impact of the WRDI and are quantified to the same scale for each of the three risk taxonomies. Each risk taxonomy features clear definitions and consistent assessment, which permits a proper comparison between candidate investments. The assessments are calibrated across taxonomies. For example, a score “6” in the reliability consequence taxonomy is comparable to a score “6” in safety and environmental taxonomies. For safety, the impact on both the workforce (employees and contractors) and the public may be considered and the higher assessment is used. For reliability, four metrics are considered (number and significance of customers, load loss, unsupplied energy, and outage duration), which capture the impact to Hydro One’s customers from interruptions. Figures 10 to 12 below illustrate the three risk taxonomies.

Taxonomy to evaluate consequences related to one failure event

Score	Impact on workforce : employee and contractor[1]	OR	Impact on public
7	▪ Multiple fatalities of employees		▪ Multiple public fatalities
6	▪ Fatality to 1 employee		▪ Fatality to a single member of public
5	▪ Permanent health consequence that precludes injured party from regular day-to-day activity (e.g., paralysis)		▪ Permanent health consequence that precludes or hinders injured party from regular day-to-day activity
4	▪ Permanent health consequence that hinders the injured party from regular day-to-day activity / doing their job (e.g., loss of hand)		▪ Permanent health consequence that does not prevent injured party from most regular day to day activity ▪ Injury to member of public requiring extended medical treatment with more than 8 weeks recovery time
3	▪ Permanent health consequence that does not prevent injured party from most regular day to day activity, e.g. doing their job (loss of finger) ▪ Injury requiring medical treatment resulting in 8+ weeks absence or temporary modified work for the employee		▪ Injury or illness to member of public requiring medical treatment with less than 8 weeks recovery time ▪ No permanent health consequences
2	▪ Injury requiring medical treatment resulting in less than 8 week absence and no modified work for the employee ▪ No permanent health consequences		▪ Minor injury to member of public requiring First Aid with quick and complete recovery in less than 1 week; No permanent health consequences
1	▪ Minor injury requiring First Aid resulting in less than a week absence and no modified work for the employee ▪ Quick and complete recovery without permanent health consequences		▪ No impact on public

Figure 10 – Safety Consequence Framework

Taxonomy to evaluate consequences related to one failure event

Score	Impact on customers	OR	Load impacted	OR	Unsupplied energy	OR	Outage Duration
7	Impacts an entire metropolitan area, including multiple customers **and** 2+ priority customers		>500 MW		>1 200 MWh		> 7 days
6	(Impacts on at least 3 customers **and** one priority customer) **or** Impact on 2+ priority customers		200-500 MW		500 -1 200 MWh		1-7 days
5	Impacts on at least 3 customers **or** including multiple critical locations **or** one priority customer		75-200 MW		200 – 500 MWh		10-24 hours
4	Impacts on at least 2 customers **or** including a single critical location		25-75 MW		25 – 200 MWh		1-10 hours
3	Impacts one customer resulting in a small area outage with no disruption of service to critical locations (e.g., water plan)		<25MW		<25 MWh		<1 hour
2	No power interruption		None		None		None
1	No power interruption and no supply through redundancy		None		None		None

Figure 11 – Reliability Consequence Framework

Taxonomy to evaluate consequences related to one failure event

Score	Description[1]	Examples[2]
7	• **Catastrophic / irreversible changes to the environment** such as entire loss of habitat, plant, and/or animal populations/ species at risk in the impacted area; will never completely recover • Chronic threat to human health; National media coverage, viral social media coverage/criminal charges/ major fines/charges	Catastrophic/negligent release of PCB oil to sensitive environmental area requiring significant remediation, engineering, and/or long-term monitoring
6	• **Significant change to the environment** – substantial loss of habit, plant and/or animal populations / species at risk in the impacted area; requires multiple years to recover completely; Chronic risk to human health; • Widespread provincial media coverage; significant fines/charges/order to comply	Very large off-site soil and/or groundwater contamination due to historical practices; significant release of PCB oil to a sensitive environmental area requiring significant remediation, engineering and/or long-term planning; catastrophic SF6 release
5	• **Notable change to environment** – visible loss of habitat, plant and/or animal populations / species at risk in impacted area; requires 1-2 years to recover completely • Definite acute risk to human health • Provincial media coverage; fines/order to comply	Large off-site soil and/or groundwater contamination due historical practices; notable PCB oil to sensitive environmental area requiring significant remediation, engineering and/or long term planning; some SF6 release
4	• **Measurable change to environment** – moderate loss of plant and/or animal populations/species at risk in impacted area; damage to environmentally sensitive sites/special interest sites; requires months/year to recover completely • Potential for acute risk to human health • Widespread local media coverage; limited fines/order to comply	Moderate on/off-site soil and/or groundwater contamination due to historical practices; measurable PCB oil, mineral oil, hydraulic oil or other hazardous liquid spill to an environmentally sensitive area requiring moderate remediation, engineering, and/or long-term planning
3	• **Limited change to environment** – limited loss of habitat, plant and/or animal populations/species at risk; requires weeks/months to completely recover • Potential for limited risk to human health • Local media coverage; inspection/ comment from regulator/order to comply but no charges/fines	PCB regulatory infraction/fine; minor on/off-site contamination from historical practices; large spill/fire of PCB oil, mineral oil, hydraulic oil or other hazardous liquid requiring remediation, engineering, and/or long-term monitoring
2	• **Limited change to environment/ requires day(s) to recover completely** • No plant and/or animal species impacted • No acute risk to human health • No media coverage; minor regulatory fine or order	Large spill/fire of PCB oil or mineral oil requiring cleanup; other large volume liquid spills requiring cleanup (i.e., hydraulic oil, coolant); SAR infraction/fine; invasive species infraction/fine
1	• **Limited change to environment/ recovers immediately after remedial action** • No media coverage; no regulatory fine or order	Typical pole-top/ padmount transformer spill of PCB oil or mineral oil requiring cleanup; other liquid spills requiring clean up (i.e., hydraulic oil, coolant) Minor liquid spills (mineral oil, hydraulc coil, coolant); minor environmental incidents (e.g., wood pole treatment seepage)

Figure 12 – Environmental Consequence Framework

The probability scoring (set out below in Figure 13 below) is an assessment of the likelihood of a failure event happening in a given year or any associated period of time based on the WRDI defined for the associated consequence. This framework has been informed by customer feedback. For example, the 4 or more failures per year under score "7" was incorporated based on customer feedback that frequent outages were highly disruptive to their operations. Hydro One assesses its investments on each framework according to the metric with the maximum score.

Taxonomy to evaluate the probability of a failure event

Score	Frequency	Expected time to event	Prob. of event occurring in the next yr.	Prob. of event occurring in the next 5 yr.	Example phrases you might hear during scoring
7	4+ per year	<3 months	100%	100%	This has happened 10 times every year for the last 5 years
6	1-4 times per year	3-12 months	100%	100%	Based on run time, the equipment life is over for 2 years, it will fail in the next year
5	1 every 1-3 years	1-3 years	33-100%	85-100%	We have to trench every 2 years, disturbing the habitat
4	1 every 3-10 years	3-10 years	10-33%	40-85%	We see this event about once a year on the whole system, which has 8 of these assets
3	1 every 10-25 years	10-25 years	4-10%	20-40%	This event happens on the system sometimes, and it's much more likely to happen here
2	1 every 25-100 years	25-100 years	1-4%	5-20%	This would happen on an APD (abnormal peak day), a 1/90 year event
1	Less than 1 every 100 years	>100 years	0-1%	0-5%	This has never happened, would be unexpected and an outlier

Figure 13 – Probability Framework

The significance and value enhancements made to the risk assessment process emphasize fact-based and quantitative decision-making to the extent possible relying on historical data and experience for the purpose of making and justifying a particular assessment decision.

2.1.4.2 FLAGGING

As part of its improved assessment process, Hydro One has introduced a new "flagging" process to account for special considerations and ensure stakeholder perspectives are consistently included in the evaluation of investments. Investment considerations that cannot be quantified using the risk framework described above are captured by using qualitative flags to allow consideration of potential benefits of an investment beyond risk mitigation. To incorporate key customer and regulatory outcomes into its evaluation of projects, Hydro One's flags enable it to identify investments that address key customer priorities such as improving power quality, and investments that align to strategic priorities and objectives.

Flags are classified as either "mandatory" or "non-mandatory". The flags were developed based on expert knowledge and Hydro One's corporate priorities. They were further customized to align with the RRF outcomes. The flagging process is intended to reduce the number of proposed investments that are considered mandatory and foster a more effective discussion of what should be completed. The net result of this process is more efficient investment prioritization and optimization, which eventually leads to lowered costs for customers.

Flagging is guided by specific and defined categories which are common and consistent across proposed investments. As risk scoring cannot always capture all relevant considerations, flags are applied to investments when such other considerations ought to be material drivers of the funding decision.

The following flags have been established to provide clear guidance and a more rigorous definition of what constitutes a *mandatory* investment:

- **Immediate / Short-term Compliance** – Explicit obligation to a regulatory agency (e.g. OEB requires work to be done *within a year* with *immediate risk* of legal breach, or there is a *two to five-year risk* of regulatory or legal breach);
- **Third party requests** – Explicit connection request by a city, county, agency, or customer, with a *one to five-year risk* of breaking the utility obligation to serve;
- **Contractual –** Signed, fixed-sum contracts with third parties for services such as IT support, facility support, etc.; and
- **In-Flight –** Project already under construction.

The following flags are used for *non-mandatory* investments and represent factors that are important to Hydro One and its customers:

- **Customer Engagement** – Influence of customer engagement/consultation; response to specific customer needs and preferences;
- **Productivity** – Contains committed productivity savings, as tracked by the company, or facilitates future productivity savings;
- **Corrective Maintenance/Demand Replacements** – A risk identified by Hydro One or other utilities that requires near-term action (e.g. break/fix);
- **Preventive Maintenance/System Renewal** – Opportunity to prolong asset life with planned and condition-based maintenance;
- **Strategic** – Codified goal by leadership team or explicit request by senior leadership; and
- **Political Commitments –** Explicit statement by Hydro One officer to non-agency parties such as politicians, media or through official public statement, etc.

2.1.4.3 CALIBRATION

Once candidate investments have been scored and flagged, the scores are reviewed in facilitated discussions among investment owners in calibration sessions. Hydro One has implemented improved enterprise-wide calibration sessions to ensure that scoring is comparable across different types of investments. Facilitated calibration sessions bring scorers and management from across the organization together to compare approaches, assumptions and quality of data used in scoring investments. The sessions ensure that all stakeholders have applied the scoring process consistently. After the session, investment owners have an opportunity to revise their scores consistent with feedback received at the session.

2.1.4.4 RISK SCORES

The results of the risk assessment are translated into risk scores, which are used to generate an initial prioritization and optimization of investments, which provides consistency across the organization. The conversion is completed using a risk matrix, as presented in Figure 14 below, and total risk mitigated is calculated by summing the risk score for each taxonomy (i.e. safety, reliability and environmental). To more effectively differentiate between the risk levels of investments with similar consequence and probability scores, Hydro One uses a logarithmic scale to assign risk scoring points.

Risk score (risk unit)

Consequence								
	7	900	4,200	12,000	36,000	100,000	400,000	1,000,000
	6	430	1,900	5,000	17,000	50,000	200,000	500,000
	5	170	800	2,100	7,000	20,000	80,000	200,000
	4	60	280	800	2,400	7,000	28,000	70,000
	3	20	80	230	700	2,200	8,000	20,000
	2	4	20	50	150	460	1,700	4,200
	1	1	3	10	30	90	350	800
		1	2	3	4	5	6	7
		Probability						

Figure 14: Risk Matrix

Based on the risk scores and cost estimates associated with each investment, candidate investments (broken into mandatory versus discretionary groups) are ranked according to risk mitigation achieved per dollar.

2.1.5 (5.3.1 B) PRIORITIZATION AND OPTIMIZATION

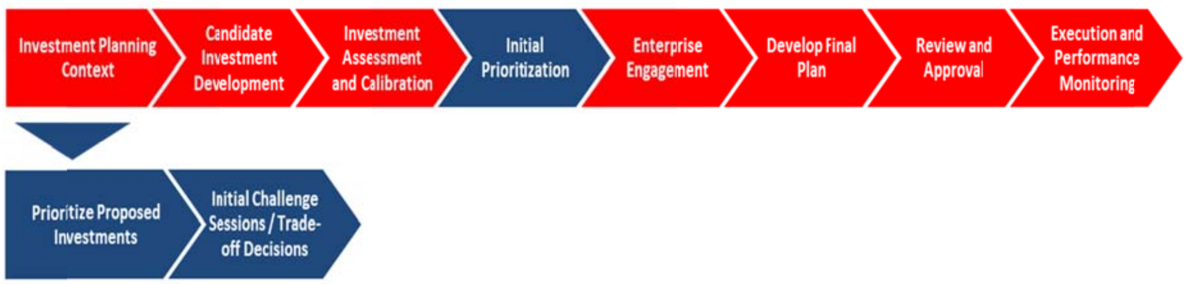


Figure 15 –Prioritization and Optimization

Prioritization and optimization has been enhanced through standardized risk scoring and the introduction of challenge sessions as presented in Figure 15 above.

2.1.5.1 CHALLENGE SESSIONS

Challenge sessions are facilitated discussions among a broad set of stakeholders (investment planning, transmission, regulatory, finance, etc.). Challenge sessions are held to (i) review an integrated portfolio, (ii) evaluate and confirm non-risk parameters (e.g. strategic, productivity investments), (iii) assess and debate investments on the margin of the funding decision, and (iv) make trade-off decisions based on facts.

Challenge sessions are designed to provide a fact-based and structured approach, aimed at defining the funded investments portfolio, with the focus on ensuring that the most valuable work to customers is included in the plan. The discussions allow for the merits of an investment to be considered from both risk and non-risk perspectives. Challenge sessions are attended by various levels and types of stakeholders, which provide for execution feasibility and strategic alignment considerations. Discussions are guided by the draft investment plan, as well as new analytic tools that enable a more holistic view of the plan's effectiveness through different lenses (e.g., comparing risk efficiency and absolute risk).

Initial challenge sessions are held to identify investments that should be funded considering factors related to risk mitigation, productivity and other non-risk parameters (i.e., qualitative flags). The output is a funded investment portfolio, which is subsequently reviewed by portfolio owners and members of the executing lines of business. Additional/final challenge sessions are then held to confirm final trade-offs.

Trade-off Decisions

As part of the challenge sessions, trade-off decisions assess which investments should be promoted or demoted based on the following levers:

- **Risk:** Is Hydro One comfortable with the remaining risk? Are there unfunded investments which mitigate large risks?
- **Flags (non-risk parameters):** Which investments need to be funded for non-risk merits?
- The consideration of both risk efficiency and risk mitigated per dollar supports the making of prudent and data-driven trade-off decisions. The final output from a challenge session typically includes:
    - prioritized plan within investment budget and associated narrative (i.e. overall theme, rationale for changes made and final portfolio); and
    - list of investments discussed during challenge session.

2.1.6 (5.3.1 B) ENTERPRISE ENGAGEMENT

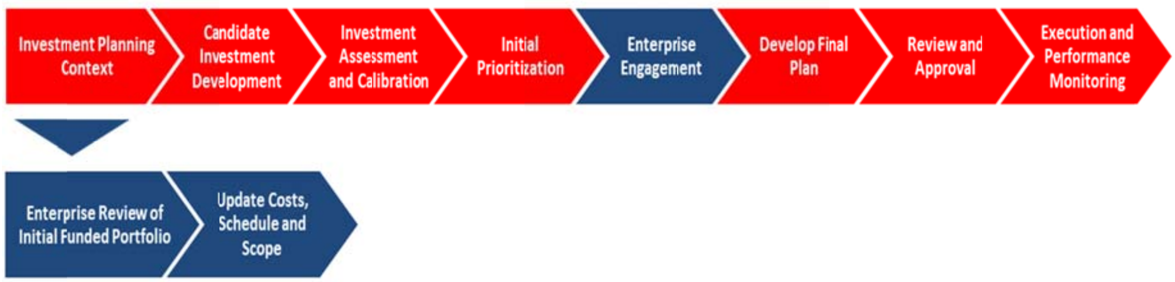


Figure 16 – Enterprise Engagement

Hydro One has improved the enterprise engagement process to ensure that the investment plan is properly reviewed and updated, where needed, by the executing lines of business. The goal is to create a realistic and up-to-date version of the investment plan to be considered at the final challenge session. Figure 16 above demonstrates the enterprise engagement process. This process incorporates operational and execution considerations such as resourcing, material availability and outage feasibility. Candidate investments are updated with the latest cost estimates, schedule, and investment scope. Enterprise review also identifies interim milestones for investment definition stages that will set the organization up for success by providing the ability to monitor the associated milestones and identify potential challenges earlier in the process. Any investments deemed infeasible, and therefore incapable of delivering the risk mitigation or other non-risk value expected, are replaced with the next best alternative. Based on discussions during enterprise engagement sessions, adjustments may be made to reflect emerging execution or asset management risks. The result of the enterprise review is a revised investment plan which is subject to a review at a final challenge session.

2.1.7 (5.3.1 B) DEVELOP FINAL PLAN

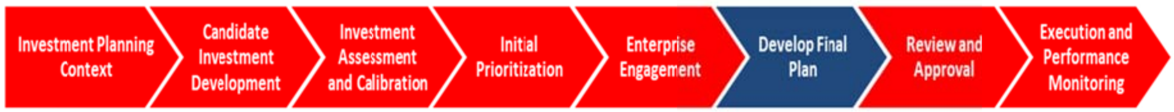


Figure 17 – Develop Final Plan

As presented in Figure 17 above, the investment plan that will ultimately be presented to ELT and the Board of Directors for approval is finalized at this stage through a final challenge session that incorporates the following:

- **Feedback from enterprise engagement review**- reprioritizing proposed investments based on what is feasible from an execution perspective.
- **Updated costs, schedule and scope**- reprioritizing based on finalized costs, permitting completion of more/less proposed investments that are on the margin.

The final challenge session output includes a prioritized investment plan and associated outcomes compared against strategic, customer, and risk considerations.

2.1.8 (5.3.1 B) REVIEW AND APPROVAL

Figure 18 – Review and Approval

Once developed, the investment plan is submitted first to the ELT and then to the Board of Directors for review and comment. The ELT and the Board of Directors review and assess the investment plan to ensure it delivers the best set of outcomes for Hydro One and its customers. In general, feedback from the ELT and Board of Directors is incorporated by returning to the initial prioritization step and repeating relevant steps in the process in consideration of the feedback received. In this Application, Hydro One is putting forward a final, approved Investment Plan, which has been approved by the ELT and Board of Directors and which incorporates their feedback..

2.1.9 (5.3.1 B) EXECUTION AND PERFORMANCE MONITORING

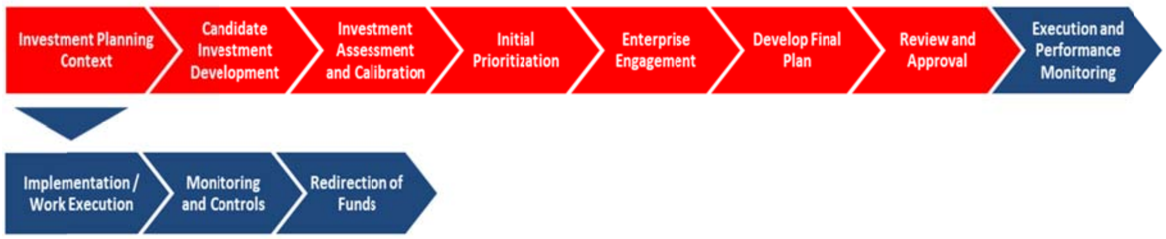


Figure 19 – Execution and Performance Monitoring

Hydro One closely monitors the execution of its investment plan to ensure it is effectively delivered. Once the Board of Directors approves the plan, the execution team takes ownership for delivery as presented in Figure 19 above. The plan is reviewed throughout the execution phase as new information on asset condition and risks become available. If needed, resources can be redeployed through the redirection process.

2.1.9.1 INDIVIDUAL INVESTMENT APPROVAL

Individual investments will be further reviewed and approved through the business case process, consistent with the provisions of the corporate expenditure authority register. Once approval is granted, the individual investments move to the implementation and work execution phase.

2.1.9.2 MONITORING & CONTROL

Hydro One monitors year-to-date expenditures and accomplishments, as well as projected year-end expenditures, on a monthly basis. Variances from the plan are identified and managed through a variance and redirection process. The approval of the variance proposal is in accordance with the limits set out in the expenditure authority register based on the cost and criticality of the investment.

2.1.9.3 REDIRECTION OF FUNDS

As changes to investments or other circumstances occur during the year, Hydro One reprioritizes during execution as new information may change one or more projects' expected value, timing, cost, customer needs, etc. In 2017, Hydro One formalized a Redirection Committee to appropriately redirect funds or authorize additional spending as necessary. Such redirection or allocation allows prudent and timely adjustments to be made to the work originally identified in the investment plan.

Hydro One's Redirection Committee: (i) oversees the redirection process where investment changes are approved, documented, systemized and communicated to the relevant stakeholders; (ii) provides advice and direction on investment adjustments to address emerging business needs or risks; and (iii) ensures an enterprise-wide understanding regarding issues affecting the execution of Hydro One's investment plan.

The Redirection Committee meets once a month. Following the review and recommendation of plan adjustments, investment level decisions are documented and communicated to appropriate stakeholders, including the recommended change and rationale. Updates regarding significant Redirection Committee decisions, as well as recommendations related to reprioritization options that require an approval authority that exceeds that of members of the committee are communicated to the ELT.

2.1.9.4 PERFORMANCE REPORTING

The final stage of the planning process is monitoring performance of the approved Investment Plan by tracking actual outcomes, measuring performance, and benchmarking. Hydro One continuously compares actual investment costs and accomplishments to the proposed investment plan. In this Application, Hydro One is proposing to include a set of key performance measures in its scorecard to track the company's performance. Hydro One also benchmarks its performance against other utilities on the basis of specific accomplishments and costs for each investment as indicators. Details of Hydro One’s benchmarking activities that informed this Application can be found in Section 1.4 of this TSP.

APPENDIX 1

OVERVIEW OF ENHANCEMENTS TO HYDRO ONE'S INVESTMENT PLANNING PROCESS ("IPP")

Table 1. Enhancements to IPP Based on OEB Feedback

	OEB Comments	Actions Taken	TSP Section Reference
1	Incorporate customer feedback into the plan in a meaningful way	• Earlier, more comprehensive customer engagement • New risk and probability frameworks informed by customer engagement feedback	Sections 1.3 and 2.1.4
2	Need a comprehensive asset condition process that informs the prioritization and explains the gap	• Risk scores are tied back to asset risk assessments and available condition assessments • Updated inventory of assets and condition assessment strategy with identified opportunities • Third-party assessments and data initiatives are underway	Section 1.4 and Attachment 13 Section 2.1.2.3 See also Section 3.2.5
3	Appropriate pacing of capital expenditures that achieves a proper balance of need and rate impact	• Enhanced enterprise-level pacing through improved planning and prioritization and optimization • Improved risk prioritization and optimization ensures that investments mitigating most risk per dollar are completed before those with smaller impact	Sections 2.1.4 and 2.1.5

	OEB Comments	Actions Taken	TSP Section Reference
4	More focus required on ability to execute the proposed capital program in a timely fashion	• Extensive review and improvement of the Capital Delivery process over the past 12-18 months to ensure processes reflect best practices and ensure safe and cost effective delivery of the capital work program • Creation of a Redirection Committee to appropriately redirect funds and resources as necessary to allow prudent and timely adjustments to be made to the work program • Enhanced upfront engineering and planning deliverables • Increased governance throughout investment lifecycle, to timely and prudently identify when redirection of funds and resources are required • Improved estimating and scheduling tools and processes	Capital Work Execution Strategy (Exhibit B, Tab 2, Schedule 1) Section 2.1.9
5	There is room for further improvement in optimization and prioritization within the process	• Clear, comparable new frameworks drive investment scoring and prioritization and optimization • Risk scores used to carry out assessment from holistic perspective (i.e. absolute risk vs. risk efficiency) and to maximize risk mitigated per dollar	Sections 2.1.4 and 2.1.5
6	Plan did not change over seven months of review	• Multiple challenge sessions are now held to provide a fact-based and structured approach to define the investment portfolio, with a focus on ensuring that the most valuable work to customers is included in the plan.	Sections 2.1.5 and 2.1.7
7	Previous plan was submitted for rate filing before Hydro One Board of Directors approval	• Sequencing issues addressed for this filing	Section 2.1.9

	OEB Comments	Actions Taken	TSP Section Reference
8	Capital and OM&A programs had not historically been delivered to OEB-approved level	• Enhanced upfront engineering and planning deliverables • Increased governance throughout investment lifecycle • Improved estimating and scheduling tools and processes	Section 2.1.9 Execution and Performance Monitoring Capital Work Execution Strategy (Exhibit B, Tab 2, Schedule 1) OM&A Work Execution Strategy (Exhibit F, Tab 1, Schedule 7)

1

2 **Table 2. Enhancements to IPP Based on Internal Audit Findings**

	Recommendation	Actions Taken/Planned
1	Annually perform a formal risk assessment to ensure that business risks facing the planning organization are identified and mitigating actions are developed and tracked.	Planning has worked with the Corporate Risk Department Group to conduct a risk workshop to identify risks in achieving the planning business objectives. The requirement to conduct risk assessments on the Investment Plan will be added to the overall Investment Planning deliverables each year. Any recommendations/action items resulting from the risk assessment will be tracked to completion.

	Recommendation	**Actions Taken/Planned**
2	Develop, review and approve sufficiently detailed policies, standards, procedures and guidelines to ensure a consistent risk-based approach to planning and decision making. This would require a review of the existing governance documents and ARIS process models for their accuracy and validity. Management has informed us that a Policy Review project is currently underway to consolidate policy and directive documents	Completed review of processes, procedures, standards and guidelines to determine their need, effectiveness, currency and to ensure they are aligned with and support the relevant operational policies. Established a review cycle for these documents; and incorporated into the Operational Policy Program the need of a Communication and Implementation Plan for all new and reviewed policies. Appropriate governance documents (e.g. policy, process, procedure, standard or guideline) will be established taking the existing Investment Planning training material into account.
3	Clarify the timing and level of input to be sought by the planners from the service providers as they develop their plans. Define and communicate the required level of engagement with the service provider when investment plans are being developed to ensure that plans are based on asset needs	It was determined that planners would discuss their investments (e.g. risks, costs) with the relevant service providers early on in the planning process so as to enable the early identification and resolution of issues. Subsequent review sessions between Planning and the service providers are scheduled to be held following the optimization process.
4	Implement a formalized Quality Assurance process and related performance measures to assess the effectiveness of the "end-to-end" planning process.	Quality expectations and associated metrics for the end-to-end process have been established by Planning, together with steps to improve quality assurance for everyday planning activities (e.g. through data validation, site assessment reports and checklists, manager/director review, and improved enterprise engagement), as well as plans to incorporate associated training through the IPP training module. Work is underway to incorporate key performance indicators for the IPP into 2018 scorecards for impacted directors.
5	Formalize and track all process and tool related training being given to planners in their Learning Management System. Establish refresher training requirements whenever there are significant changes in process and tools.	Training for end-to-end investment planning has been developed and rolled out to planners. Attendance is being tracked on a local basis.

	Recommendation	**Actions Taken/Planned**
6	Document and communicate lessons learned after each planning cycle and use them for continuous improvement of the planning process.	Survey results and action plan associated with opportunities for improvement have been completed and shared across the organization.
7	Request an audit of Asset Analytics (“AA”) data sources and algorithms to confirm that quality data and appropriate calculation methods are used for calculating the six Asset Risk Indexes for individual assets as well as asset groups.	Efforts to improve AA algorithm is currently underway, including SAP data audit on asset and maintenance data. Workshops between Planning and the lines of business have been set up to consider existing AA algorithms. A tender has been issued seeking input from potential vendors related to their expertise and high-level estimated cost to improve AA. Plans relating to AA data, including associated milestones and recommendations, will be tracked in the Divisional Scoreboard.
8	Consider expanding the scope of the AA tool to include up-to-date power system historical data such as load flows, connectivity, voltages, statuses, etc.	A tool enhancement roadmap has been prepared and submitted to Management, which will review and determine the necessary enhancements taking into account cost/benefit associated with decisions to keep, defer or discard items.
9	Continue to develop sufficiently detailed Asset Strategy Documents for all asset groups and ensure that all future asset needs are assessed against these documented strategies.	Asset strategy development is a continuous improvement process to address asset needs and respond to emerging issues. Hydro One has reviewed and revised strategy documents for the majority of Transmission Lines, Stations and Protection & Automation assets. These are among the most critical assets in Hydro One’s transmission system. To further strengthen Hydro One’s asset management capabilities, the development of new strategy documents for minor assets is currently underway.
10	Increase the number of investments that are optimizable by requiring more robust definitions of project alternatives.	Through more rigorous documentation and communications around relevant program governance requirements, the proportion of optimizable investments with multiple alternatives has increased from 24% in 2014 to 30% in 2016 and to 67% in 2018. This is inclusive of both Transmission and Distribution investments.

	Recommendation	Actions Taken/Planned
11	Simplify the risk assessment matrix and provide suitable training and guideline to planners to perform an effective risk assessment. Specific focus should be on using quantitative data from AA and other systems to determine/support appropriate probability and consequence on the established risk matrix.	Specific risk training was developed for the 2017-22 planning cycle using the established corporate risk universe matrix. A mapping has been developed to consistently apply AA risk score to the AIP risk matrix.
12	Review and confirm the Unit Price Catalogue ("UPC") with the service providers prior to the start of each planning cycle to ensure that the most current unit prices are being used to determine the funding level for the program work.	The IPP has included a deadline for the service provider to provide a draft UPC and a deadline for the Planners to review and accept the UPC.
13	Make the AIP tool available year around to allow the planners to input and update their plans and risk assessments throughout the year.	Based on consultation with vendor, year round availability was deemed to be too costly and cumbersome to implement (i.e., it is Hydro One's understanding that it is not typical for utilities to adopt this capability). However, more time is made available for planners to input and update their plans throughout the year.
14	Increase the enterprise engagement period to allow a detailed line by line review of unreleased work in the IPP by the project and program managers who will be executing the plan.	The Enterprise Engagement period was extended (from 4 days to 4 weeks) starting with the 2016-2020 IPP cycle. Planning and the execution lines of business were encouraged to discuss preliminary plans, costs and risks associated with investments during the input period.
15	Implement a formal change log to document all recommended changes. This should also include appropriate review, approval and incorporation of changes with appropriate communication back to the requestor of the changes.	Change log was implemented starting with the 2016-2022 IPP cycle.

	Recommendation	**Actions Taken/Planned**
16	Determine and document which types of changes to the individual plans require the IPP to be run through the optimization process again to ensure that the resulting plan remains optimal.	Optimization condition guideline was developed and incorporated into the investment optimization manager procedural document starting with the 2016-2020 IPP cycle. The guidelines document the conditions to be met in order to optimize or re-optimize the investment plan, establishes best practices to handle post-optimization changes, and establishes expectations in terms of documentation.
17	Clarify the approval requirement and progress monitoring for "projam" (i.e. station-centric) investments. Review the project and program approval process with specific focus on shortening the approval timeline.	All projam investments have been converted to projects to follow more robust processes already in place for project initial approvals and variances.

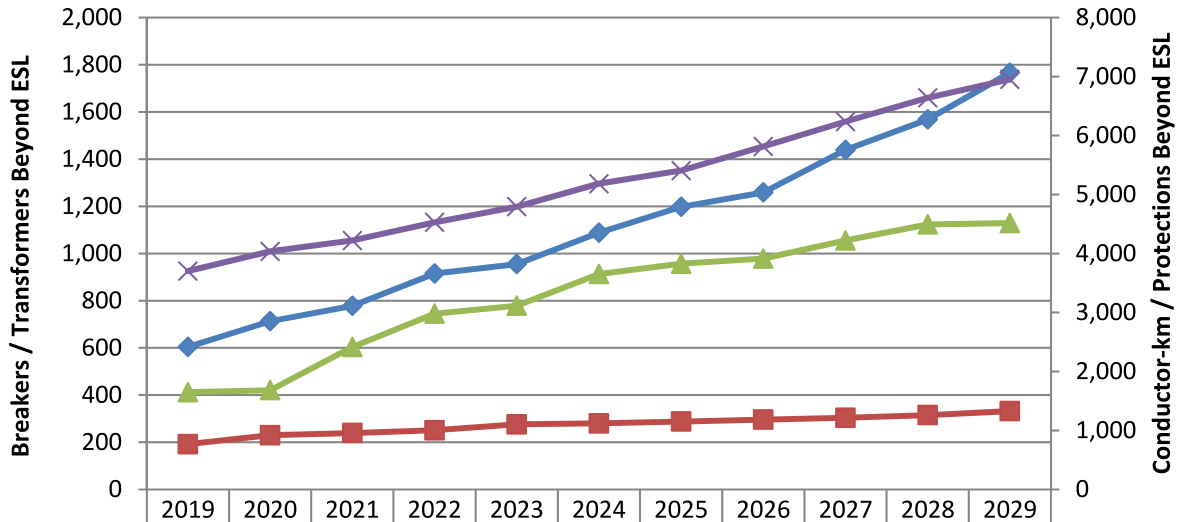
2.2 (5.3.2) ASSET COMPONENT INFORMATION

This section presents the characteristics, condition and outlook for Hydro One's transmission assets which are covered by its asset management process, as well as its common assets such as Fleet, Facilities and Information Technology. The asset lifecycle optimization policies and practices for these assets are found in TSP Section 2.3.

Hydro One uses the Expected Service Life ("ESL") of assets as a general guideline to inform investment decisions. The ESL is defined as the average time duration in years that an asset can be expected to operate under normal system conditions and is determined by considering manufacturer guidelines and Hydro One's historical asset retirement data. Assets operating beyond ESL generally have a higher likelihood of failing or being in poor condition.

The term End of Life ("EOL") is also used and is defined as the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences. Therefore, while assets may be operating beyond ESL they may not be at EOL. At the same time, as the primary driver of replacement decisions, asset condition will be verified prior to the work being undertaken.

Figure 1 shows the forecasted cumulative number of assets that will exceed their ESL from 2019 through to 2029 in the absence of any planned or unplanned replacements. There is significant demographic pressure on some asset classes as their ESL will increase by 1.7 to 2.9 times absent replacement. This rapid shift poses inherent operating and resourcing risks that must be planned for and mitigated through proactive and strategically paced investments in order to prevent pressure on OM&A and capital costs and to maintain customers' expected level of service.



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Breakers	604	713	778	915	955	1,088	1,198	1,259	1,439	1,568	1,766
Transformers	192	230	239	251	276	280	288	296	304	315	332
Conductor	1,650	1,683	2,416	2,980	3,115	3,653	3,828	3,914	4,221	4,493	4,516
Protections	3,703	4,036	4,220	4,529	4,795	5,184	5,406	5,814	6,236	6,639	6,952

Figure 1 - Number of Assets beyond ESL per Year Summary

Hydro One tracks asset utilization for certain assets and asset classes. However, utilization is not the ultimate driving factor in asset replacement decisions.[1] Utilization is defined by major asset class using available and applicable asset characteristics. In the case of transformers, utilization is defined by historical loading as a ratio of the nameplate capacity rating. Utilization for breakers is defined as a combination of the total count of operations, breaker nameplate fault rating relative to available system fault

[1] There have been instances where Hydro One replaced assets with higher rated equipment to satisfy system performance standards pursuant to the IESO Market Rules and/or Transmission System Code (Appendix 2). For example, to enable the connection of distribution generation facilities, a number of equipment replacements were made around 2009 so as to increase short circuit capacity and thermal ratings of stations and lines.

current and fault adjusted operations (i.e. cumulative current interrupted). For information regarding utilization and asset replacement decisions, see TSP Section 2.3.

The risk rating of individual assets is based on the probability of failure determined through qualitative and quantitative assessment. Quantitative assessment considers the results of diagnostic testing as well as the corrective history of the asset which may indicate a higher probability of failure. Qualitative assessment is based on engineering analysis and judgment to assign a relative risk level. Examples of qualitative considerations include technical obsolescence (i.e., lack of manufacturer support), potential health and safety concerns, the nature and detail of trouble calls and deficiency reports, visual inspection and maintenance records, and operating conditions or system configurations that may cause undue stress on assets. The risk ratings of major transmission stations and lines assets have been summarized in Table 1 below. Hydro One plans to address assets with a high, or very high, risk condition before they affect reliability and the level of service expected by customers.

Table 1 - Major Asset Condition Summary

Asset Type	Very Low Risk*	Low Risk	Fair Risk	High Risk	Very High Risk*	To be Assessed
Transformers	336	163	95	99	23	-
Circuit Breakers	2035	1475	804	293	167	-
Protection Systems	4,800	3,846	497	2,387	976	-
Conductors (km)	16,050		3,316	3,680		6,061
Wood Poles	-	17,640	0	5,460	-	18,900
Underground Cables (km)	-	179	77	8	-	0

** These categories are not used for all assets.*

To address the reliability of the transmission system, Hydro One considers many asset-related factors including the condition, ESL, utilization and overall performance of the asset. The cumulative contribution of each major asset to delivery point interruptions over the past decade is illustrated in Figure 2 below. Since 2008, lines, protection and control equipment, transformers, and breakers have been the predominant sources of equipment-related delivery point interruptions, highlighting the significant impact they have on system reliability.

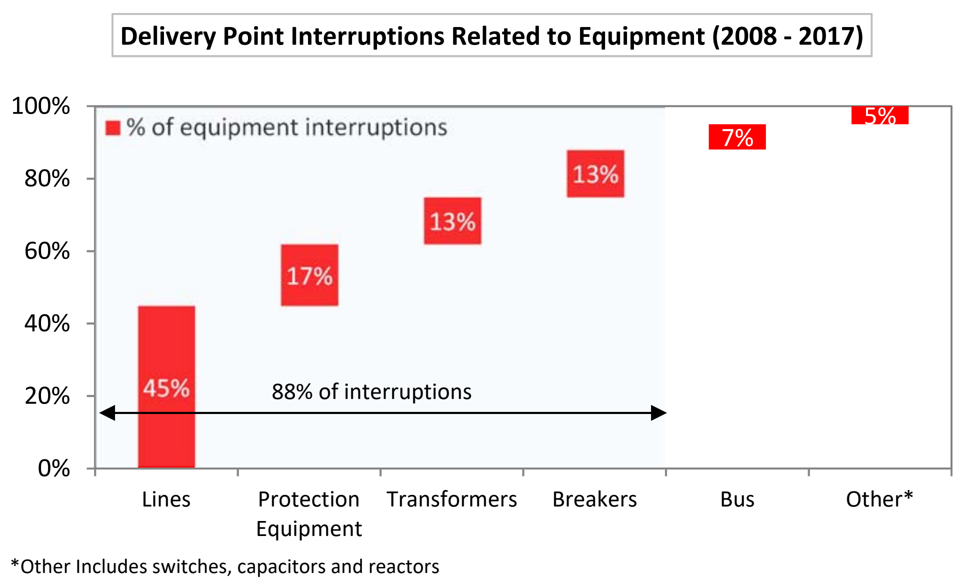


Figure 2 - Delivery Point Interruptions Related to Equipment (2008 through 2017)

Asset component information for stations (including transformers and breakers) and lines is provided below in TSP Sections 2.2.1 and 2.2.2 respectively. TSP Section 2.2.3 discusses general plant assets.

2.2.1 (5.3.2 B, C, D) ASSET COMPONENT INFORMATION – TRANSMISSION STATIONS

This section discusses the main assets that are found in transmission stations, including transformers, breakers, protection schemes, control and monitoring equipment, power system telecom equipment, switches, capacitor banks, instrument transformers, ancillary equipment and civil structures.

2.2.1.1 TRANSFORMERS

Asset Description / Purpose

Transformers are extensively used in electric power systems to convert power from one voltage level to another. Hydro One operates the following types of transmission class power transformers from 115kV to 500kV primary voltages levels, as summarized in Table 2 below:

Table 2 - Transformer Fleet Description

	Transformer Type	Description
	**Step-down**	Step-down transformers convert transmission voltages (50 kV or higher) to distribution voltages (less than 50 kV)
	**Autotransformer**	Autotransformers are a special type of power transformer, used to cost effectively transform voltages and currents between transmission system voltage levels (higher than 100kV)
	**Phase Shifter**	Phase shifting transformers are employed in selected locations to optimize power flows across international tie-lines.
	**Regulator**	Regulator transformers provide voltage regulation through the use of an internal tap changer.
	**Reactor**	Shunt reactors are a single winding device that absorbs reactive power from the system as a way of controlling voltage and increasing the energy efficiency of the system.

Asset Condition / Demographics

Demographics

As of December 2018, Hydro One had 716 transmission class transformers in service, as outlined in Table 3 below. Currently, 24.7% of Hydro One's transformer population is beyond ESL. ESL varies based on transformer type as outlined in Table 3. The average

age of the transformer fleet is 30 years. Assuming no replacement, Hydro One anticipates that 280 units (39% of the transformer population) will exceed their ESL by 2024, and 332 units (46% of the population) will exceed their ESL by 2029.

Table 3 - Summary of Transformer Demographics

Type of Transformer	Voltage	Quantity	Average Age (Years)	ESL (Years)	Currently Beyond ESL	Beyond ESL *2024	Beyond ESL *2029
Step-down	500 kV	1	7	40	0	0	0
	230 kV - 2 winding	172	32.88	50	37	72	87
	230 kV - 3 winding	126	26.04	40	24	38	53
	115 kV - 3 winding	112	31.53	40	53	57	63
	115 kV - 2 winding	161	29.63	60	29	53	58
Auto	500 kV	42	25.46	40	12	14	14
	345 kV	4	41.25	50	0	2	2
	230 kV	89	37.38	50	18	39	50
Phase Shifter	230 kV	4	30.25	40	1	2	2
Regulator	230 kV	2	31.5	40	1	1	1
Reactor	500 kV	3	39.33	40	2	2	2
Total		**716****	**30.8**	**-**	**177**	**280**	**332**

Data current as of 31 December 2018
** As of December 31 of that year assuming no failures or replacements*
***Three Single phase banks in one operating designation only count as one transformer*

<u>Condition</u>

Transformer condition is a leading predictive indicator of equipment reliability. Condition is determined by industry standard diagnostic testing which includes routine transformer oil testing and other maintenance examinations. Transformer insulation generally degrades as a function of time and this degradation is irreversible, ultimately requiring asset replacement. According to Hydro One's assessment of the transformer fleet's condition, 17% of transformers are rated high or very high risk based on oil testing results up to 2018, as illustrated in Figure 3 below.

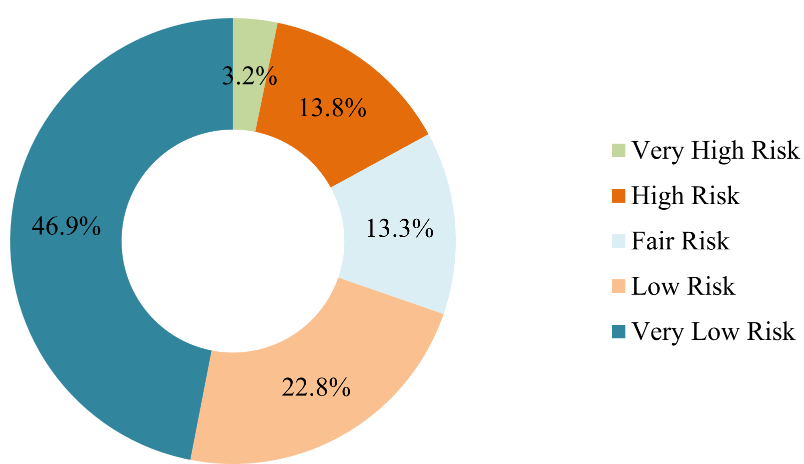


Figure 3 – Transformer Fleet Condition Assessment

Further, 40% of the transformer fleet has been confirmed via visual inspections to have oil leaks, with 10% being classified as major leakers, as illustrated in Figure 4 below. Based on Hydro One's experience, new leaks will appear in approximately 1% of the fleet per year, most commonly as a result of gasket deterioration over time. Transformer leaks not only create environmental concerns, but also lead to reliability issues (e.g. in-service transformers may be forced out due to low oil levels). Active leaks also provide a path of moisture ingress into the transformer's internal winding, which can cause Class 1 transformer failures. Finally, severe oil leaks and frequent oil top ups also compromise the accuracy of condition assessments because these activities dilute the oil and may result in a false improved oil test result.

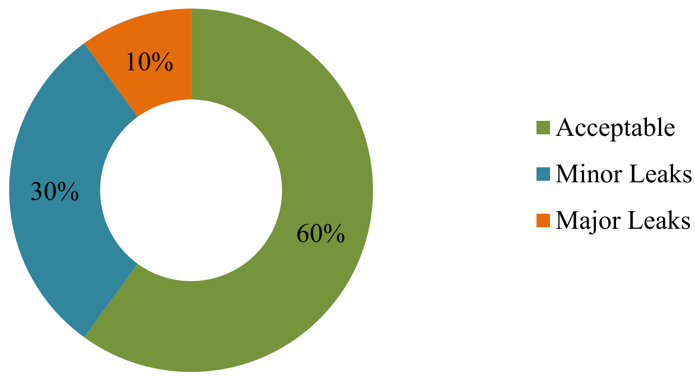


Figure 4 – Transformer Leak Assessment Overview

Federal Polychlorinated biphenyl ("PCB") regulations require all PCB contaminated equipment to be removed from service by 2025. Details regarding applicable PCB requirements are provided as part of the discussion regarding breakers in the Asset Condition / Demographics section below (the same regulatory requirements apply to breakers and transformers). As of December 2018, 43% of Hydro One's transformer oil-filled bushings that are manufactured pre-1985 require work related to PCB testing verification or replacements. Hydro One has an ongoing program to sample equipment with unknown PCB content. By the end of 2018, it is estimated that 6,267 pieces of transmission equipment still require sampling, the majority of which are transformer or breaker bushings.

Performance

Transformer equipment performance is measured by assessing the duration and frequency of forced outages related to the transformer. A "forced outage" is the automatic or forced manual removal of a transformer caused directly by it or its auxiliary equipment.

Transformer forced outages have been a major cause of equipment unavailability over the past 10 years, representing 13% of these equipment-caused events as shown in the Introduction of this section.

As shown in Figure 5 below, the forced outage duration resulting from transformer forced outages in recent years is generally consistent with the average for the past decade. The increase in duration from 2015 to 2017 (compared to 2013 and 2014) is driven by a combination of factors, primarily transformer failures which required replacements. Examples of major contributors in 2015 include failures of Trafalgar TS T15 (500-230kV autotransformer), Bridgman TS T6 (115-13.8kV step-down transformer), and Lorne Park TS T1 (230-28-28kV step-down transformer). The contribution of transformer failures to forced outage durations persisted through 2016, where the failure of the Red-Phase of Essa TS T3 (500-230kV autotransformer) was the major contributor to outage duration. The failure of Campbell TS T2 (230-13.8k-13.8V step-down transformer) in 2017 was one of the contributors to the outage duration in that year.

The effect of fleet-level condition deterioration (as illustrated in Figure 3) contributed to the increase in forced outage duration observed from 2015-2017. The most frequently observed issues were associated with unsatisfactory testing results, tap changer malfunctions and auxiliary equipment failures (where transformer replacement was not required). Lastly, oil leaks, along with instrument transformer defects (e.g., affecting current and voltage transformers)[2] continued to play a significant role as contributors to outage duration.

[2] Failure of instrument transformers can result in the removal of the transformer from service. This is because the OGCC would lose visibility to voltage and current through a transformer due to the loss of a voltage/current reference.

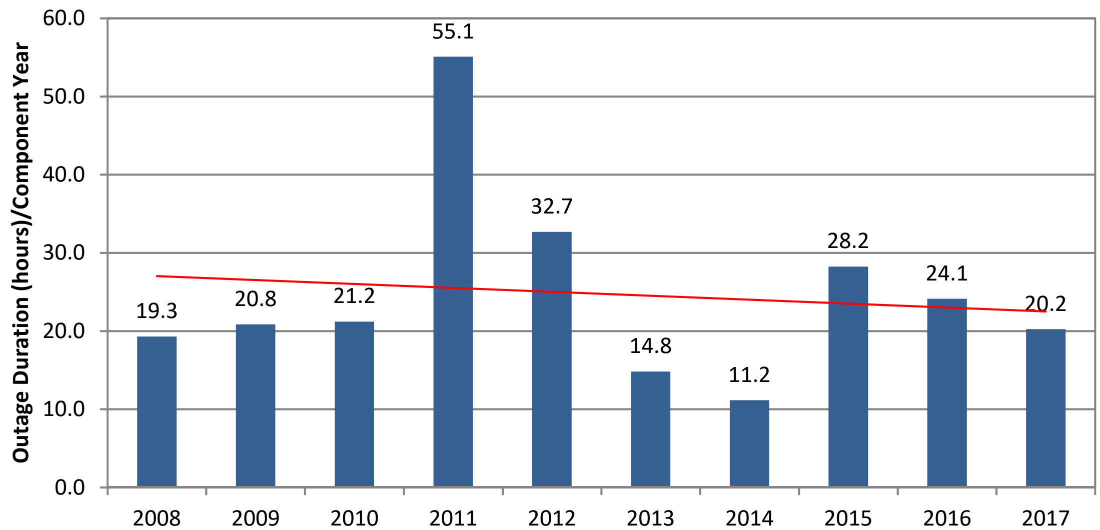


Figure 5 - Forced Outage Duration of Transformers

Overall, the forced outage frequency of transformers has improved over the past 10 years as shown in Figure 6 below. Nevertheless, historical reliability performance is a lagging indicator of transformer condition and is not necessarily predictive of asset need. In fact, as explained above, fleet-level deterioration can be reasonably expected to negatively impact asset performance (and thus contribute to increased equipment outages) over time in the absence of proactive investments to address the issue.

It is important to understand that a forced outage will not always result in an interruption to customers. In other words, forced outage statistics speak to equipment availability, and not necessarily to the actual level of reliability experienced by customers. Therefore, improvements observed in outage frequency statistics do not eliminate the underlying need to address actual asset condition, which is ultimately the underpinning driver for asset replacement decisions. In this regard, every transformer in the replacement plan will be verified to be in such a condition that is no longer suitable to provide long term service reliably.[3]

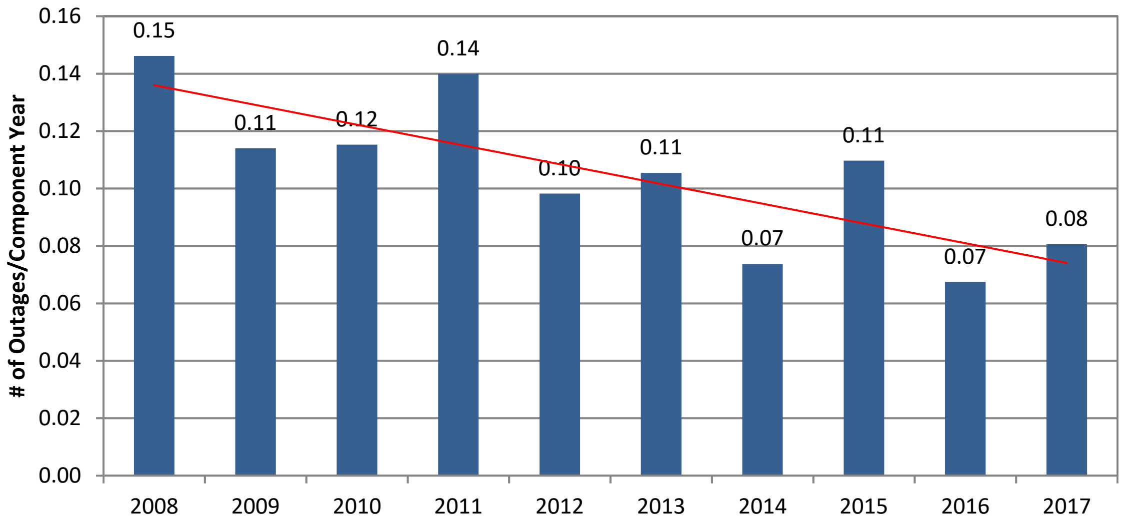


Figure 6 - Forced Outage Frequency of Transformers

Over the last 10 years, Hydro One has experienced an average of four Class 1 transformer failures annually. Class 1 failures are unpredictable and irreparable, and can lead to catastrophic consequences. For example, a major failure of Richview T7 and T8 in 2011 resulted in both transformers being engulfed in fire, producing smoke that severely impaired traffic on Highway 401 during rush hour. Table 4 below summarizes the number of Class 1 failures by voltage class.

When comparing the 2008-2012 period to the 2013-2017 period, the failure rate of 500kV transformers has doubled from 1.41% during 2008 to 2012 to 2.44% during 2013 to 2017. The failure rates of 115kV and 230kV transformers have remained relatively

[3] See discussion in Section 1.4 regarding EPRI's verification of Hydro One's asset condition assessment.

stable over the same 10-year period. More frequent 500kV failures may be attributed to design and manufacturing deficiency, higher operating voltage and loading requirements.

Table 4 - Annual Class 1 Transformer Failure Rates over the Past 10 Years (2008-2017) in Percentage of Transformer Population

Year	115kV	230kV	500kV	5 Year Average Annual Failure Rate, All Voltage classes
2008-2012	0.40%	0.37%	1.41%	0.44%
2013-2017	0.56%	0.41%	2.44%	0.59%
10 Year Average Annual Failure Rate	0.48%	0.39%	1.92%	0.51%

Future Outlook / Need

Hydro One's plan for its transformer fleet over the next five years has been influenced by fleet demographics, observed conditions, anticipated conditions, and performance factors as well as environmental and safety concerns. The plan aims to sustain the transformer fleet via maintenance and replacements. Based on Hydro One's transformer demographic profile described in Section 2.2.1.1, it is anticipated that an increasing number of units will age beyond their ESL within the next five years. Transformer ESL is known to have a direct correlation to anticipated insulation condition.[4] Operating a large percentage of the fleet beyond their ESL increases the risk to system reliability as there is an increased probability of failure as the transformers age. The increasing proportion of transformers in a high and very high-risk condition can be expected to continue if no investments are made to mitigate this risk.

[4] This correlation can be measured via the detection of furan – a by-product of insulation paper degradation – in transformer oil samples as an indicator of insulation strength and condition.

Consequently, Hydro One plans to manage this anticipated risk by replacing approximately 25 transformers annually from 2020 to 2023, which would allow Hydro One to maintain the ratio of transformers that are within, rather than beyond their ESL, with condition being the primary driver for replacement. After 2023 and once the transformer demographic forecast shown in Figure 7 is achieved, the replacement rate is expected to decline. Through the proposed replacement rate, Hydro One would be able to maintain the number of units that are beyond ESL by the end of 2029 to approximately the same level as 2019.

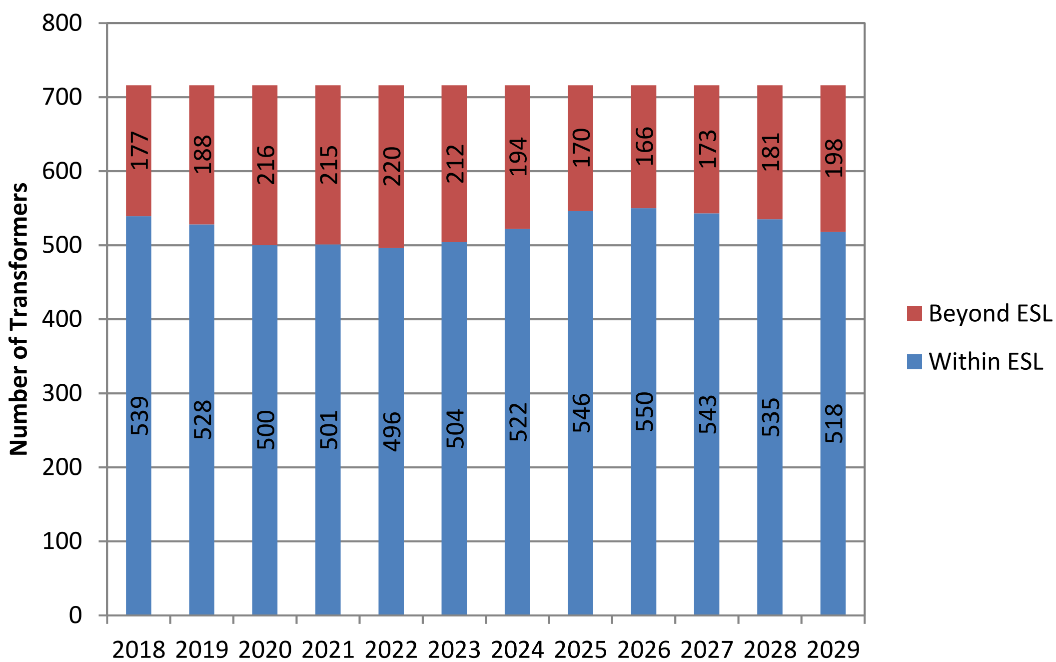


Figure 7 – Transformer Demographic Forecast – With Replacement

Hydro One's 500 kV transformer fleet has recorded a higher failure rate compared to transformers of other system voltages, particularly in the last five years. In the next ten years, approximately twenty 500kV autotransformers are planned for replacement. To support the in service fleet, Hydro One has a sparing strategy is in place to mitigate the impact of unplanned failures across all transformer types. Validation of the Hydro One transformer spare strategy and model is discussed in Section 1.4.

2.2.1.2 CIRCUIT BREAKERS

Asset Description / Purpose

A circuit breaker is a mechanical switching device that is capable of carrying and interrupting electrical current under normal and abnormal conditions. During abnormal conditions, circuit breakers are capable of operating rapidly to interrupt high current thereby minimizing its effect on the rest of the power system.

Circuit breakers use a variety of interrupting mediums that have evolved over time. Hydro One's circuit breaker fleet has been summarized in Table 5 below according to the interrupting medium used, along with the production and environmental status.

Table 5 – Breaker Fleet Description

	Breaker Type	Interrupting Medium	Production Status	Safety and Environmental Concerns
	Oil Circuit Breakers ("OCB")	Oil	Legacy, Out of Production	Oil spill, PCB* content
	Air Blast Circuit Breaker ("ABCB")	Air	Legacy, Out of Production	Noise
	Sulfur Hexafluoride ("SF6") Breaker	SF6	Commercially available	SF6 is a greenhouse gas

	Gas Insulated Switchgear (“GIS”)	SF6, Vacuum**	Commercially available	SF6 is a greenhouse gas
	Metalclad Switchgear	SF6, Vacuum, Air, Air Magnetic	Commercially available	Arc flash hazard
	Vacuum Breaker	Vacuum	Commercially available	None

** Polychlorinated Biphenyls (“PCB”)*
*** MVGIS uses vacuum interrupters as interrupting medium and SF6 acts as insulating medium*

Asset Condition / Demographics

Demographics

Hydro One has 4,774 High Voltage (“HV”) and Medium Voltage (“MV”) breakers. The breaker fleet includes 549 breakers that are currently beyond their ESL. Projections for 2024 and 2029 (assuming no replacements or failures) are summarized in Table 6 below. A large number of oil, air blast and metalclad breakers have reached their ESL with an increasing number of breakers forecasted to reach ESL within the next decade. As breakers approach their ESL, vendors typically communicate their transition to limited support or complete obsolescence of aged product lines. It is important to proactively manage and mitigate this impending wave of assets approaching ESL in order to avoid difficulties in obtaining spare parts to sustain breakers that vendors no longer support.

Table 6 - Summary of the ESL of Hydro One's Breakers*

Type of Breaker	HV 115-500kV	MV 44-12.5kV	Total	Avg. Age	ESL (Years)	Currently Beyond ESL	Beyond ESL **2024	Beyond ESL **2029	% of Fleet Currently Beyond ESL (2018)
Oil Breaker	377	1,242	1,600	42.2	55	151	499	773	9.40%
Air Blast Breakers	133	24	157	46.5	40	129	157	157	82.20%
SF6 Breakers	783	1,074	1,857	14.2	40	10	17	142	0.50%
GIS Breakers	276	88	364	23.9	40	108	147	161	29.70%
Metalclad Breakers	0	767	767	27.8	40	151	268	341	20%
Vacuum Breakers	0	29	29	15.4	40	-	-	3	0.00%
Total	**1,569**	**3,224**	**4,774**	**27.6**		**549**	**1088**	**1766**	**11.50%**

* data current as of Dec 30, 2018
** as of December 31 of that year assuming no failures or replacements

Condition

Breaker condition is monitored through information gathered during preventive inspection and maintenance activities. Breaker failures can severely impact system stability, other connected equipment and employee and public safety. Consequently, it is important to ensure that the current carrying components are in good shape, the mechanical and control systems are operating within specification and that the insulating medium has not been compromised.

As breakers age their O-rings and gaskets slowly degrade, thereby causing leaks, which will result in a lower pressure and a path for moisture ingress. Over time, this condition can result in lower dielectric strength in the breaker and potential for internal flashover, which could lead to an explosive failure of the breaker. Where feasible based on parts availability, cost and projected future reliability, breakers with leaks are repaired as part of ongoing maintenance activities.

As of December 2018, the breaker fleet's condition shows that 9% are rated at a high or very high risk, as illustrated in Figure 8 below.

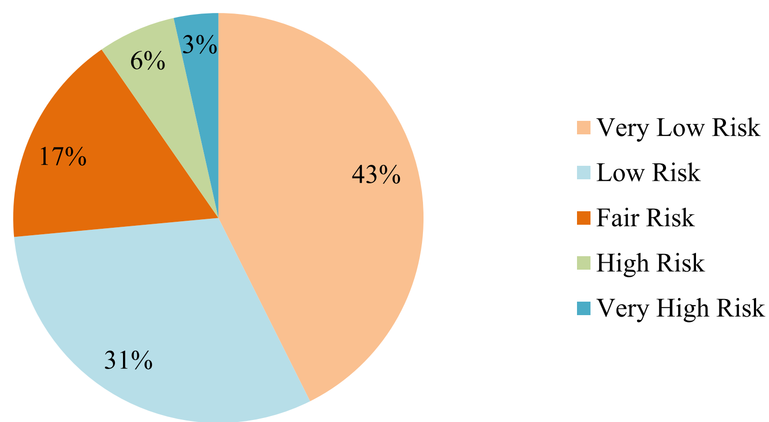


Figure 8 - Overall Breaker Fleet Condition

Performance

Circuit breaker performance is measured by assessing the number of forced outages. A "forced outage" is the automatic or forced manual removal of high voltage breakers caused directly by the breaker itself or terminal equipment directly adjacent to the breaker. Typical breaker failure modes have included control component issues, air leaks, gas leaks, operating mechanism issues, moisture content problems and auxiliary equipment malfunctions.

The number and duration of forced outages due to circuit breakers have increased over the past decade with a flattening trend in the last five years, as illustrated in Figure 9 and Figure 10 below. This overall increase is primarily attributed to the number of ABCB-related forced outages.

The significant increase in the 2013 forced outage frequency was predominantly due to the increase in ABCB air system control component failures. The CGE AT breaker population experienced the greatest number of air system component failures. In some cases, such failures led to breaker fail protection operations that forced the tripping/opening of adjacent breakers. This can cause interruptions to circuits and busses, which could give rise to customer outages. These performance issues have also resulted in multiple instances where generators were forced offline.

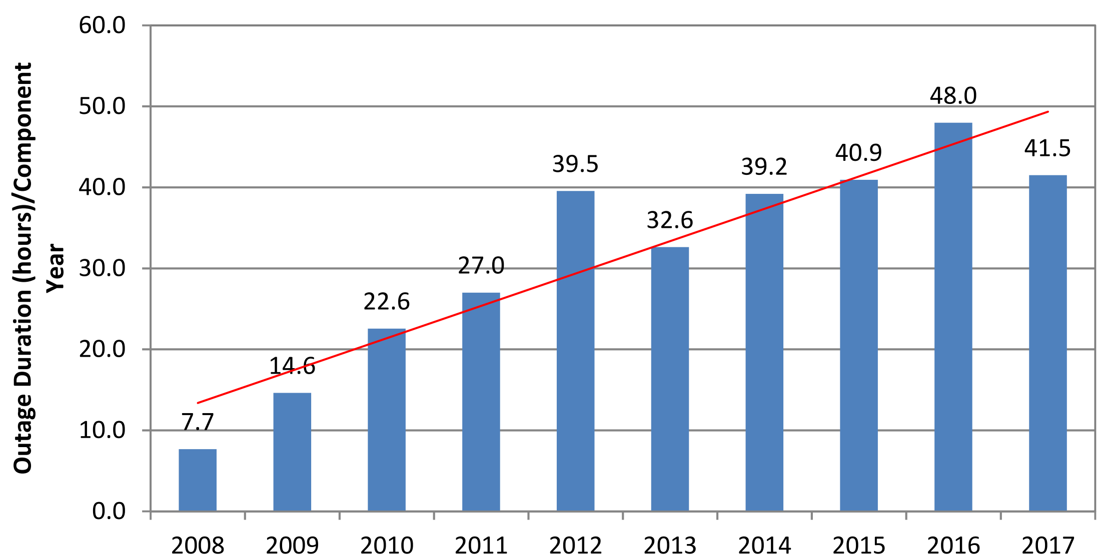


Figure 9 - Circuit Breaker Forced Outage Duration

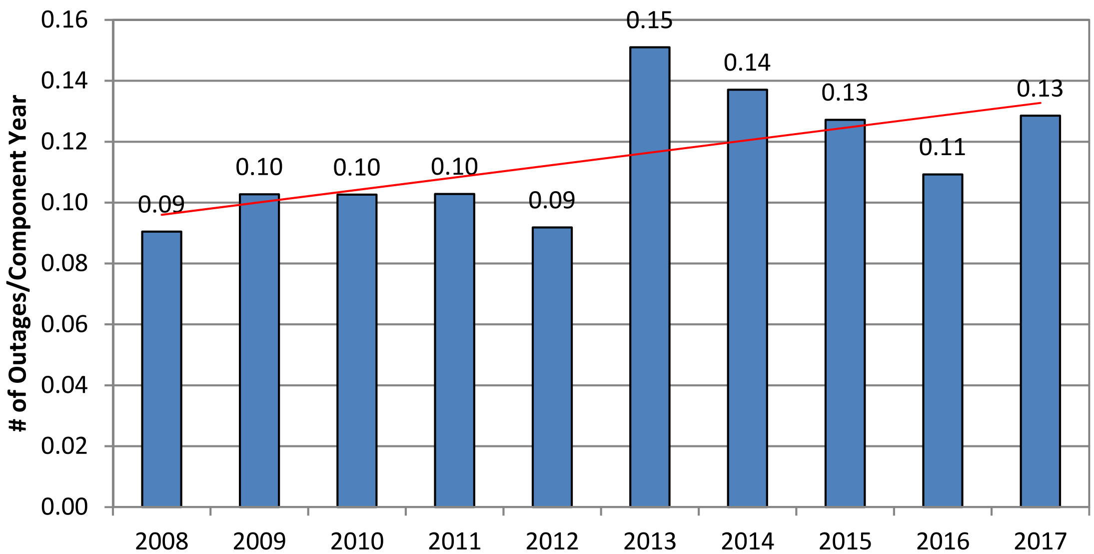


Figure 10 - Circuit Breaker Forced Outage Frequency

Forced outage frequency by breaker type in Figure 11 below illustrates the doubling of ABCB related outages over the last 10 years. This increasing trend is due to known air system issues caused by deteriorated O-rings, valves and problems with control components.

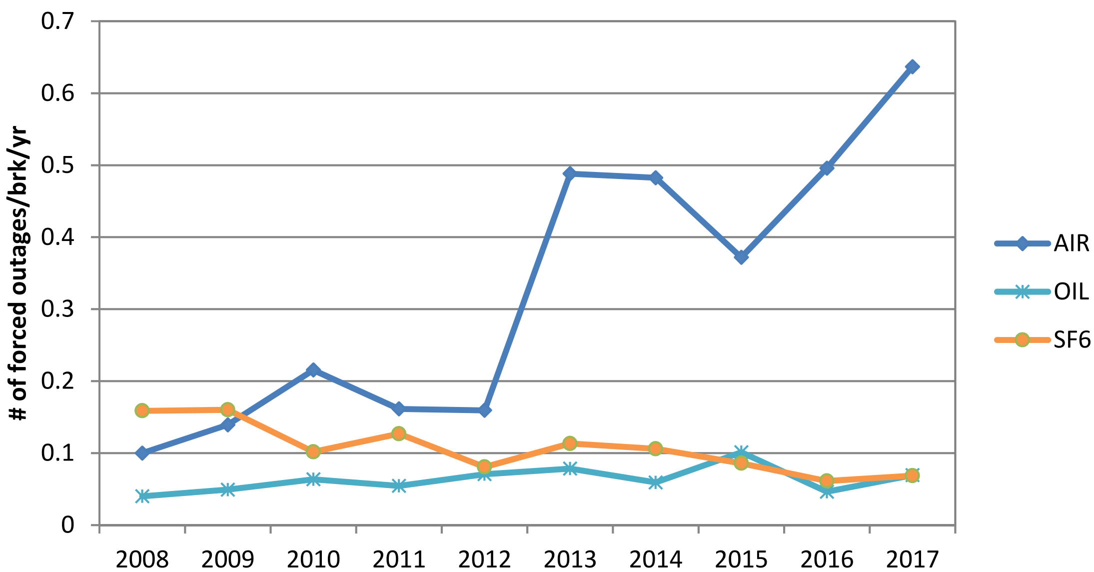


Figure 11 - Summary of Forced Outages by Breaker Type

Vendor Support

Some of the Hydro One fleet of breakers (approximately 2% of the overall fleet) are no longer supported by vendors and aftermarket parts are no longer available or are costly to acquire or fabricate. This is a significant risk factor to the ABCB fleet, some first generation SF6/GIS circuit breakers and certain types of oil circuit breakers. Where parts are difficult to procure, specific units are replaced so the decommissioned devices can serve as strategic spares for the remaining in-service fleet.

Air Leaks

Severe air leaks are a significant concern for the ABCB fleet as large groupings of breakers are supplied by a common airline. In the winter months issues arise with air pressure and safety valves as they freeze in the open position. This leads to the loss of air and subsequently, the loss of breaker control. This can result in the removal or isolation of multiple adjacent breakers and high voltage circuits, thereby causing large load interruptions and generation bottling.

Polychlorinated Biphenyls (“PCB”)

Hydro One plans to sample all oil filled equipment in its Transmission Stations (“TS”) manufactured prior to 1985 by the end of 2020 and remove or retro-fill the PCB oil filled equipment to less than 45 parts per million (“ppm”) by year end 2024. This timeline allows for a one year buffer for any outstanding issues to be identified and addressed in order to meet the federally mandated completion deadline of year end 2025.[5]

Based on a review of the error margin associated with the applicable analytical methods, Hydro One established a limit of 45 ppm, which provides 95% confidence that the

[5] As per Canadian Environmental Protection Act, 1999 – PCB Regulations SOR/2008-273.

federally mandated limit of 50 ppm will be met upon regulatory verification. These requirements impact breaker oil filled bushings and the oil in the main breaker tank. It is estimated that approximately 528 breakers require PCB mitigation, which entails replacing or retro-filling the bushing (i.e., putting in new PCB free oil to bring the PCB ppm value lower). To date, Hydro One has sampled 779 breakers, with another 168 breakers projected to contain high PCB content once sampled. This projection is based on the rate at which Hydro One has been finding high PCB concentrations in the equipment sampled to date.

SF6 – Greenhouse Gas

Sulfur Hexafluoride ("SF6") is a common and effective dielectric medium used in a large portion of the breaker fleet. Hydro One continues to monitor and track its SF6 emissions. Hydro One primarily has issues with leaks on its SP model type population of breakers (211 in total). There is a known leak point on the bushing flange for which there is a repair procedure, but there is a subset of the population (about 5% identified so far) for which these repairs do not prove to be effective, thereby requiring replacement.

Future Outlook / Need

Hydro One's plan for the breaker fleet over the next five years has been influenced by the demographic, condition, performance, vendor support, air leak, PCB factors described above and health and safety concerns. The plan aims to employ maintenance and replacements in order to maintain fleet performance.

In order to limit the number of breakers beyond ESL, Hydro One plans to replace on average 128 breakers annually from 2020 to 2024. The approach is to target specific breaker populations to deal with system risks, and steadily pace investments driven by obsolescence caused by reduced vendor support for aged product lines. Early vintage GIS has begun to approach the point where vendors are declaring obsolescence, but maintenance is still a viable option in the short term to deal with reliability and SF6 issues. Integrated GIS replacements are expected to commence outside of the current five year planning period. Replacement of breakers is prioritized and paced through the ARA and investment planning process which places an emphasis on executing projects that will mitigate the most risk. A summary of the replacements have been described below:

Table 7 - Summary of Breaker Replacements

Type of Breaker	# for Annual Replacement*	Reason for Replacement
Oil Breaker	49	• obsolescence, no vendor support • non-compliance with current system operating ratings • PCB regulatory compliance
Air Blast Breakers	21	• significant negative impact on outage frequency • deteriorating condition and performance • obsolescence, reduced or no vendor support • elimination of high maintenance costs
SF6 Breakers	12	• no vendor support • SF6 emissions
GIS Breakers	1	• reliability concerns • obsolescence • SF6 emissions
Metalclad	41	• arc flash hazards • obsolescence, reduced or no vendor support
Vacuum	2	• obsolescence, reduced or no vendor support
Total	**128**	

**Annual average replacement planned for the next five years*

2.2.1.3 PROTECTION SCHEMES

Asset Description / Purpose

Hydro One's protection systems are comprised of instrument transformers, relays, sensors and communication devices. The protection system is a critical element of the transmission system that detects abnormal system conditions. Upon detecting an abnormal condition, the protection systems immediately cause the necessary station equipment to operate to isolate faulted components. If not isolated in time, a faulted element could cause a cascading effect resulting in a major system disruption involving service interruptions, equipment damage and employee and public safety issues.

Protection system components also capture detailed records for post event analysis. This information assists in determining the root cause of power system events and facilitates the mitigation or elimination of the issue. The three vintages of protection systems found at Hydro One are summarized in Table 8 below.

Table 8 - Protection Fleet Description

	Protection Type	Description
	Electromechanical Systems	Electromechanical systems utilize the principles of electromagnetic induction to convert electrical energy to mechanical movement in order to detect faults.
	Solid State Systems	Solid State systems rely on integrated circuit technology to detect fault conditions.
	Microprocessor Systems	Microprocessor based protection systems, also known as Intelligent Electronic Devices ("IED") are the newest technology. These relays utilize microprocessors to offer multiple protection functions and additional features. These features enable post-fault technical analyses not available in legacy technologies.

Asset Conditions / Demographics

Hydro One currently has 12,506 protection systems in-service. Approximately 27% of the protection system population is operating beyond its ESL. Furthermore, over 90% of the solid-state fleet is already operating beyond ESL, as outlined in Table 9 below. Such devices are subject to an elevated risk of failure, while also having very limited or no support from vendors in terms of replacement units, spare parts, and engineering and firmware support. As such, reactive repairs may involve extended durations as re-engineering and construction work will be required to install new devices based on different technology. These risks could lead to protracted outages for customers.

Table 9 – Summary of the ESL of Hydro One's Protection Systems by Technology*

Protection Type	Quantity	Avg Age (Years)	ESL (Years)	% Beyond ESL (if no protections are replaced) **					
				2018		2024		2029	
				Qty.	% of Type	Qty.	% of Type	Qty.	% of Type
Solid State	2,026	35.3	25	1,835	91%	1906	94%	1941	96%
Electro-mechanical	3611	38.8	45	1,322	37%	2,038	56%	2,279	63%
Microprocessor	6,869	8.7	20	206	3%	1,240	18%	2,732	40%
TOTAL	**12,506**	**27.6**		**3,363**	**27%**	**5,184**	**41%**	**6952**	**56%**

* data current as of Dec 31, 2018
** as of December 31 of that year assuming no failures or replacements

Hydro One is currently analyzing the ESL for microprocessor relays as internal and industry experience suggests that the 20-year figure may not apply to many vintages and models in this category. The historic ESL for these types of relays was based mainly on original manufacturers' statements of product support, ESL of device components and the average lifespans for similar devices adopted by peer utilities.

Witness: Donna Jablonsky, Lincoln Frost-Hunt, Rob Berardi

Hydro One uses the ESL of relays as a trigger to further investigate the health or condition of a relay and the risk of its potential failure with respect to reliability and safety. Kinectrics performed an assessment on behalf of Hydro One regarding the ESL of specific relays, including solid-state and microprocessor relays and found the ESL was in-line with utility practice but could be increased for the two assessed model types. Refer to TSP Section 1.4 for further information.

Condition

Programmable Auxiliary Logic Controller ("PALC") relays are a type of solid state protection system. They have shown an increase in recorded defects and trouble calls over the years due to deteriorating components within the relay. As a result, and due to the inability to obtain replacement units, PALC relays are considered high risk assets. Hydro One has been actively replacing PALC relays since 2014 and to date, approximately 250 PALC relays have been replaced. This has driven down the number of annual defects as shown in Figure 12 below. Hydro One still has approximately 300 PALC relays in operation and plans to replace them over the following five years.

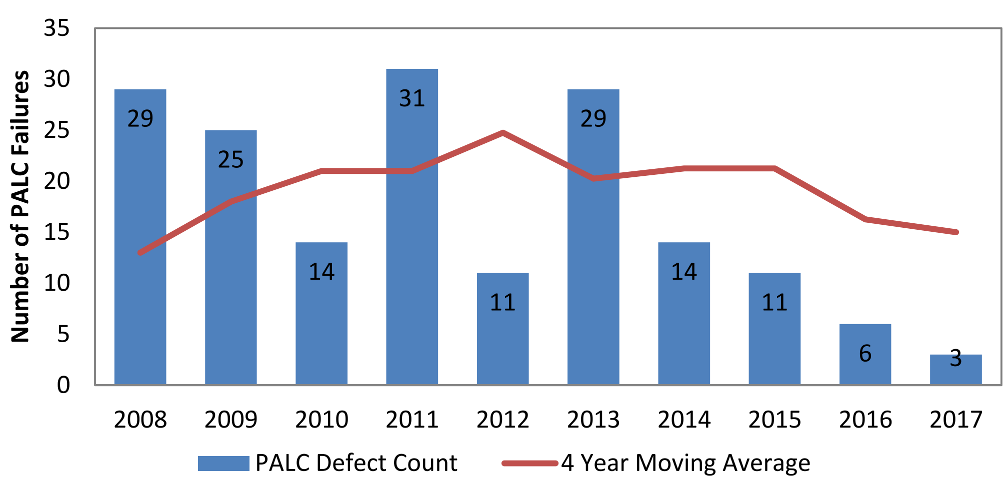


Figure 12 - Number of PALC Relay Defects

Performance

Protection system misoperations are the single most important indicator of the protection system's overall performance. Hydro One tracks the performance of the protection system by analyzing every protection system operation to determine if it operated as expected. A subset of this data that relates to devices that form part of Hydro One's Bulk Electric System ("BES") (approximately 40% of all Hydro One assets) is reported to the North American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating Council ("NPCC") as part of the company's compliance obligations. Based on NERC data, Hydro One is able to track its protection system performance compared to other utilities in North America. As shown in Figure 13, Hydro One's BES protection system misoperation rate is generally at or below the level experienced by other utilities in North America.

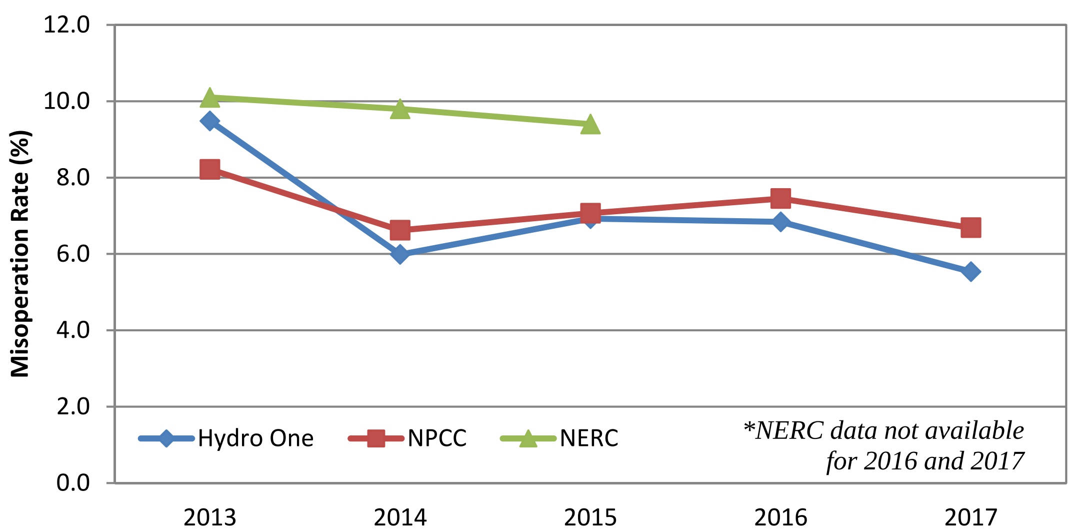


Figure 13 – Misoperation Rate (%)[6,7]

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[6] http://www.nerc.com/pa/RAPA/ri/Pages/ProtectionSystemMisoperations.aspx

Misoperations can be categorized into two types: hardware failure and incorrect settings. Between 2008 and 2017, on average, 6.6% of station protection misoperations and 11.1% of line protection misoperations were caused by human error (incorrect settings) while the rest can be attributed to hardware failures.

Future Outlook / Need

Hydro One's replacement strategy for protection systems is focused on replacing systems that have a high likelihood of causing delivery point interruption and impacting the reliability of BES.

Because it is not easy to monitor the condition of all protection systems, ESL and other factors are used as a trigger to identify high risk assets which undergo further condition assessment to identify replacement candidates. Other factors driving protection system replacements are summarized below:

- Safety – Protection system failure to operate can potentially expose workers and the public to the risk of electrocution, which can result in significant injuries or fatalities. Proactive replacements are required to mitigate this risk.
- Regulatory Compliance – Hydro One's protection system must comply with all applicable NERC and NPCC standards. Protection system upgrades are often needed in order to comply with new or updated standard requirements.
- Historical Performance – An increase in the rate of failures over the historical period can indicate fleet deterioration.
- System Reliability Risk – The impact of protection on power system reliability depends on its location in the power system, the criticality of the protected element, protective function and redundancy. Power system reliability risk due to

[7] NPCC figures include misoperation data from ON, QC as well as US states of Maine, New England etc. NERC data combines data from all of North America

potential protection failure or misoperation is being factored in the replacement decision process.

- Functional Requirements – The requirements for protection system functionality may change due to power system changes (e.g., system stability requirements) or changes to other components of the integrated protection and automation system, which may lead to incompatibility of the existing protection hardware with the associated devices.
- Technology Obsolescence – Many protection system components are no longer available, limiting the availability of spare parts and support; which can adversely impact outage planning and overall system reliability. This is a significant factor for electromechanical and solid state systems as they are no longer supported by relay vendors which are focusing their efforts on microprocessor based relays.
- Innovation – New microprocessor based protection systems have advanced monitoring and diagnostic capabilities which can provide insight into station equipment performance and early detection of problems, potentially avoiding equipment damage.

2.2.1.4 AUTOMATION

Asset Description / Purpose

Automation assets are complex electronic systems that enable the monitoring and control of power system assets and facilities at all times to achieve the safe, reliable and efficient operation of the Ontario transmission grid. They also enable timely responses to emerging problems, real-time condition assessments, restoration activities, and work planning.

Automation systems provide several critical capabilities such as:

- Local and remote real-time monitoring, control and troubleshooting facilities for Hydro One field staff, control center staff and the IESO in accordance with Market Rules;
- Critical transmission station automation and integration functions to support the operations of all power system equipment;
- Collection, processing, and archival of non-operational data for post-event analysis and to support the asset management decision-making processes;
- Enabling cyber security functionalities such as system event monitoring, authentication, authorization, logging and accounting;
- Supporting the fulfillment of regulatory obligations; and,
- Interfaces with external utilities, generation, and customers.

Hydro One's automation assets consist of legacy and modern technological vintages, as described below.

Legacy Automation Equipment

Legacy automation components primarily consist of Remote Terminal Units ("RTU"). This equipment is based on the concept of physical wiring and the digital conversion of electrical signals delivered by wires, generally for a single function/application. These systems utilize slow communication connections and employ a variety of protocols.

Modern Automation Equipment

Modern automation equipment is network enabled to utilize high-speed communications and has a smaller physical form-factor, exponentially increased computational capabilities, and greater ability for integration with the Network Management System ("NMS") as compared to its legacy counterparts. Information is conveyed through standard protocols which shift previous manual labour work related to hard wiring, towards skilled programming capability.

Asset Conditions / Demographics

There are over 18,000 components and devices in service to support automation functionalities of Hydro One's Power System Monitoring & Control ("PSMC"). Forty six percent (46%) of the automation system population is of the modern vintage type, while 54% is of the legacy vintage type. The ESL for automation systems, outlined in Table 10 below, is classified according to their vintage and is based on generally accepted industry practices and Hydro One's experience.

Table 10 - Automation System Expected Service Life

Automation Vintage	***Expected Service Life***
Legacy (copper-based)	20 years
Modern (IP-based)	15 years

Condition

Automation system condition is an important indicator of equipment reliability. Internal components degrade as a function of time, which can alter the performance of the automation equipment.

Hydro One has been tracking the reliability of automation equipment (i.e., on the basis of relevant defect reports, trouble calls, and potential need identifications) with the objective of determining future work programs. Based on those statistics, presented in Table 11 below, legacy systems have experienced defects four times more often than modern control systems within the past decade. Moreover, 54% of automation equipment is of the legacy vintage, and makes up 79% of the total defect occurrences. This is expected to trend upward as the fleet continues to age.

Table 11 - Summary of Defect Reports (2008-2018)

Year	LEGACY			MODERN			
	RTU	**PSR**	**Transducer**	**LMC/LCC**	**Gateway**	**Router**	**Switches**
2008	325	23	19	11	18	4	2
2009	550	68	21	27	25	5	0
2010	635	42	36	19	18	10	1
2011	674	69	29	52	12	4	2
2012	555	39	20	43	34	20	9
2013	577	48	14	71	30	17	10
2014	431	39	29	67	38	19	19
2015	384	39	31	78	56	16	18
2016	478	44	16	195	63	24	20
2017	912	8	3	208	63	31	43
2018	465	14	6	136	98	21	82
Total	**5986**	**433**	**224**	**907**	**455**	**171**	**206**

Future Outlook / Need

Hydro One's plan for its automation assets is focused on the following key objectives:

1. Evaluation of modern industry offerings and migration towards cost-effective alternatives. The legacy technology and design has been in service for over thirty years. Risks and costs are mounting as more of these systems reach or exceed their ESL. As Hydro One modernizes its automation fleet though the deployment of station Local Area Networks ("LAN"), there is no longer a need for expensive legacy RTU installations. Modern solutions have a small form factor, are a fraction of the cost, and are IP-based with flexible scalability to match the company's needs.
2. Optimization of existing designs to reduce capital and OM&A expenditures. Hydro One will be evaluating changes in controls design architecture to maximize device functionalities. Many existing deployments were designed with legacy technologies that provided certain capacities or redundancies to meet reliability requirements. As some legacy technologies are discontinued and replaced with modern industry offerings, reliability targets and mandated requirements will be met with reduced or no redundancy required.

In comparison to protection, the automation world has seen significant advancements over the past decade. Hydro One is undertaking these opportunities to further modernize and bring improvements to operational efficiency, reduce operational risks, and cost containment. Examples of such initiatives include: (i) removal of EOL Local Controller Computers and implementation of the same functionality into Station Gateways; (ii) deployment of direct Supervisory Control and Data Acquisition ("SCADA") to allow stations to communicate directly with the Ontario Grid Control Centre ("OGCC") so as to phase out hub sites; and (iii) substitution of multiple Local Maintenance Computers at a station with a single transient cyber asset which complies with the NERC Critical Infrastructure Protection ("CIP") standards.

2.2.1.5 POWER SYSTEM TELECOM

Asset Description / Purpose

Power System Telecom includes communication systems, infrastructure, and leased facilities that enable essential protection, control, monitoring and operation of the transmission system in Ontario.

Power system telecom services ("PSTS") are used for the following applications:

- Station-to-station telecommunications used by protection systems;
- Telecommunications between the control center, hub site and transmission stations for remote monitoring and control of equipment; and
- Communications with customer owned protection and control equipment.

Power System Telecom assets are categorized as part of the following systems or asset types:

- Synchronous Optical NETworking ("SONET") transport network;
- Fibre optic cable infrastructure;

- Power Line Carrier ("PLC") systems;
- Teleprotection terminal devices;
- High Voltage Protection ("HVP") systems;
- Microwave radio systems; and
- Provincial Mobile Radio System ("PMRS").

In addition to the above telecom assets, Hydro One also:

- Utilizes carrier-based leased services to provide PSTS. These include communication channels over copper pairs as well as Virtual Private Networking ("VPN") services from telecommunication providers;
- Engages Hydro One Telecom, an affiliate of Hydro One, for operational services for the communication network that include coordinated network management, vendor management, alarm based monitoring and system analysis services;
- Leases approximately 1,700 km of fibre acquired under Indefeasible Right of Use ("IRU"); and,
- Leases sites and/or space from third parties for the provincial mobile radio system.

SONET Transport Network

Hydro One's communication network is based on SONET technology and is primarily utilized by protection systems and SCADA systems. Additionally, it is used for communicating non-operational data, business data, voice and security information, and is used as backhaul for the provincial mobile radio system. The network topology is such that stations are connected in the form of a ring to provide redundant communication links that can stretch up to hundreds of kilometres long across the province.

The SONET network utilizes multiplexer equipment composed of two vintages; the first generation initially deployed between 1998 and 2007 and the second generation from

2004 onwards. In addition to the multiplexer equipment, the SONET network includes microwave links, optical amplifiers and 48Vdc power supplies. There are certain segments of the network that are made up of microwave links as opposed to fibre connected paths. These obsolete microwave links have created a capacity/bandwidth limitation on a typical ring topology.

Fibre Optic Cable Infrastructure

Hydro One utilizes fibre optic cable infrastructure including Hydro One owned/operated aerial fibre optic cables and fibre strands acquired through IRU. Aerial fibre optic cable is primarily comprised of (i) Optical Ground Wire ("OPGW") technology with strands of fibre embedded inside the shieldwire mounted on top of high-voltage transmission structures and (ii) All-Dielectric Self-Supporting ("ADSS") fibre cable that is attached to towers or poles typically below the phase conductors.

Power Line Carrier Systems

Power Line Carrier ("PLC") systems are used by Hydro One to provide an alternative means of dependable communications between stations. These systems use high-voltage power lines as the communication medium. The primary components include radios, line traps, matching units and coupling capacitors.

Teleprotection Terminal Devices

As part of the standalone or integrated teleprotection systems, teleprotection terminal devices provide an interface between the protective relay and the communication network, SONET or carrier-based leased services. Based on the communication medium used, these devices are classified as:

- T1 access multiplexers that provide digital teleprotection over the SONET network; and,

- Tone devices that cater to teleprotection applications over leased facilities.

High Voltage Protection ("HVP") Systems

Hydro One leases telephone communication circuits from third party telecommunication service providers which may be subjected to a very high voltage rise when a fault occurs on the power system, thus potentially exposing personnel and equipment to hazardous high voltages. For this reason, special HVP is required for all of Hydro One's leased telecom.

The primary component of the HVP system is the High-Voltage Interface ("HVI") equipment that provides the required electrical isolation and safe limits of any difference in potential. Hydro One's inventory of HVI equipment includes neutralizing transformers, isolating transformers and optical isolators.

Microwave Radio Systems

Hydro One's licensed microwave radio systems support the SONET network and last mile point-to-point telecom applications. The microwave radio systems are supported by infrastructure that includes marked radio communication towers to satisfy aviation safety requirements, microwave buildings, and backup power supplies. Hydro One's communication towers are also utilized by the provincial mobile radio system and for third party attachments.

Provincial Mobile Radio System

Hydro One owns and operates a private radio system that is used for two-way voice communication between control centers and field crews during restoration efforts, emergency operations and day-to-day construction and maintenance work. The mobile radio provides coverage that exceeds the cellular coverage in remote areas, and is often the only means of communication in these areas. The system includes radio base stations and radios equipped in Hydro One's fleet.

Asset Conditions / Demographics

Hydro One currently owns 4,229 microprocessor based communication devices, 1,203 ancillary communication equipment, 145 radio communication towers, 143 mobile radio base stations and approximately 2,178 km of fibre optic cable that, combined with 1,700 km of third-party fibre acquired through IRU, make up the communication systems and infrastructure used to provide PSTS.

Hydro One takes into account asset age, manufacturer recommendations and historical asset retirement in order to determine ESL and to plan asset replacements. Field deficiency reports, trouble calls and failure incidents provide an indication of the overall condition of the power system telecom assets. The ESL for most microprocessor based equipment is 15-20 years. Table 12 shows typical ESL in years for each type of power system telecom asset.

Table 12 – Summary of Telecom Asset Type

Telecom System/Asset Class	Asset Type	Quantity	Expected Service Life (Years)	Currently Beyond ESL*	Beyond ESL 2024	Beyond ESL 2029
SONET Communication Network	Multiplexers	263	15	86	197	247
	Digital Radios	35	15	35	35	35
	Optical Amplifiers	32	15	29	31	32
	48 VDC Batteries	281	10-20[1]	23	49	141
	48 VDC Chargers	281	20	87	129	165
	OPGW	2,017 km	40	0	0	0
	ADSS	161 km	15	161	161	161
Power Line Carrier Systems	PLC Radios	431	20	228	305	392
Teleprotection Terminal Devices	T1 Multiplexers & Tone Devices	3165	20	1025	1880	2655
Microwave Radio Systems	T1 Radios/ Sub-T1	303	15	17	39	170

Telecom System/Asset Class	Asset Type	Quantity	Expected Service Life (Years)	Currently Beyond ESL*	Beyond ESL 2024	Beyond ESL 2029
Radio Communication Towers	Hydro One Owned	145	80	Unknown		
	Leased space	71	N/A	N/A		
High-Voltage Protection System	Neutralizing/Isolation Transformers/ Opto-Isolators	641	30-50	325	Unknown	
Provincial Mobile Radio System	Radio Base Stations Equipment	143	20	143	143	143

Note: "Unknown" denotes assets for which there is insufficient data.
[*] Data as of December, 2018
[1] Varies based on equipment make and/or model

SONET Transport Network

The first vintage of multiplexer equipment is approaching its ESL and is facing technological obsolescence as vendors withdraw support and, as such, spare parts become increasingly harder to find. The majority of SONET equipment failures are associated with the first vintage of multiplexer equipment (Vintage A MUX) as shown in Figure 14. These failures have resulted in multiple power system telecom services being rendered unavailable until repairs were carried out.

Loss of communications channels can result in the removal of power system equipment from service and/or power flow constraints on the transmission system (as protection systems dependent on communications cannot protect the equipment and the OGCC loses visibility of the status of the equipment). In turn, this can have a negative impact on the reliability of the transmission system, and potentially expose customers to a less reliable configuration due to the loss of redundancy.

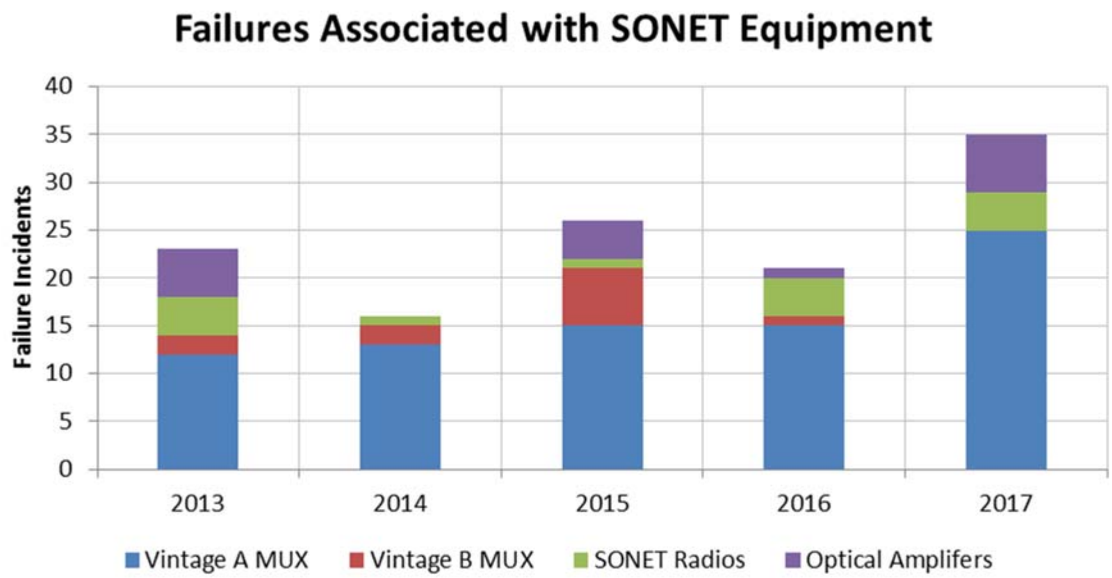

Figure 14 – Failure Incidents for SONET Equipment

Hydro One is experiencing degraded performance by many of the SONET digital microwave radio systems. Due to the age and performance of these systems, and the significant reliability risk they pose, more frequent preventive maintenance is currently being carried out until they can be replaced.

Batteries are a critical component for the normal operation of the SONET's power supply and degrade significantly once they exceed their ESL. Hydro One plans to minimize the number of batteries that exceed ESL and is monitoring the condition of those that remain. There are, however, certain types of 48Vdc charger units in the Hydro One fleet that are prematurely failing due to internal component failures and thus require replacement. Hydro One is targeting these known problematic units along with those that exceed ESL for replacement.

Fibre Optic Cable Infrastructure

The ESL of fibre optic cable is based on the type of cable. The manufacturers' recommended ESL for OPGW is 40 years and 25 years for ADSS. Historical performance shows that the mechanical aspects of fibre cable have prematurely reduced the cable's life span. In the case of ADSS cables, premature failures have caused its ESL to be lowered to 15 years.

In terms of reliability, leased fibre routes perform significantly worse than Hydro One-owned OPGW sections as they tend to be installed on public road allowances, on wood poles, or along railway tracks which makes them more prone to frequent and sometimes prolonged outages due to road accidents or train derailments. The worst performing SONET ring in the Hydro One network is Ring 7 (located north of Essa in North/North Eastern Ontario) which was built using 100% third party provided fibres. Figure 15 shows the historical occurrences of fibre breaks for each SONET ring.

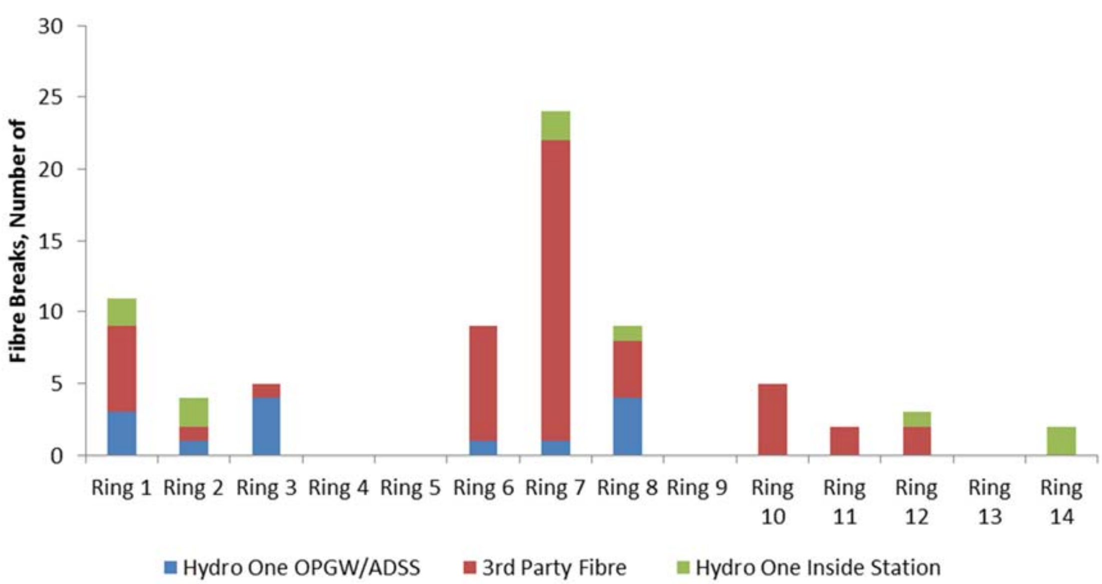

Figure 15 - Fibre Breaks by SONET Ring (2009-2017)

Power Line Carrier Systems

PLC radios have an ESL of 20 years as these are considered microprocessor based devices. Outdoor equipment such as line-traps, tuners and coupling capacitors have an ESL of 40 years, similar to that of other station yard equipment such as power instrument transformers or HV/LV switches.

Approximately 60% of the PLC radios exceed their ESL, are no longer supported by the manufacturer and are considered technologically obsolete. As shown in Figure 16 below, these vintages of radios have been contributing to the majority of the defects that Hydro One has experienced on its PLC systems.

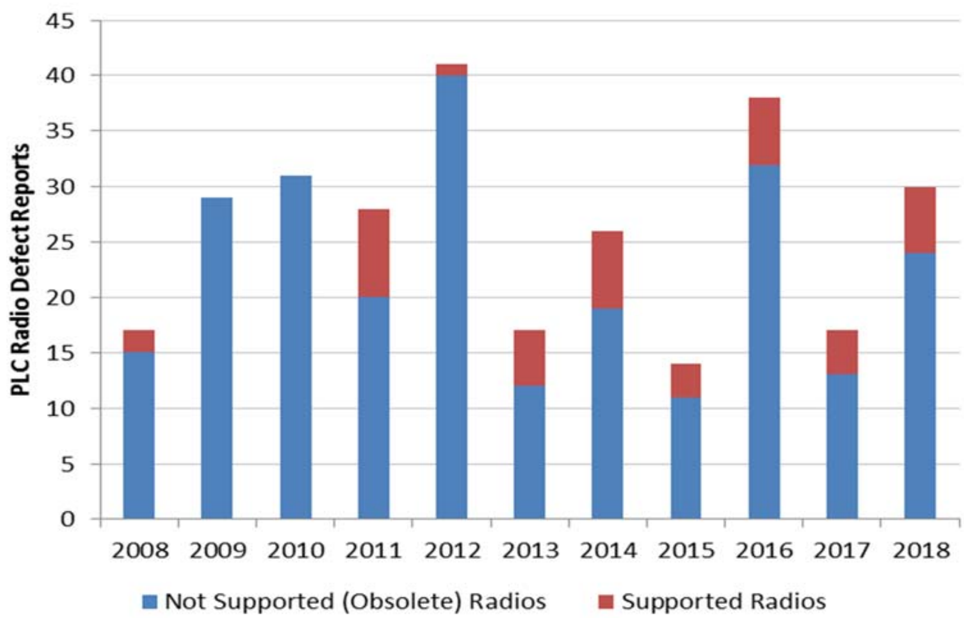

Figure 16: PLC Radio Deficiencies

Failure of the outdoor passive PLC equipment is significantly less compared to the indoor PLC radios. Since 2010 there have been only 17 failures or defects associated with outdoor PLC equipment compared to 15 defects of PLC radios on an annual basis.

Teleprotection Terminal Devices

Based on the industry-accepted ESL for microprocessor based devices, the ESL of these communication devices is estimated to be 20 years. The majority of T1 access multiplexers were deployed as part of the analog microwave replacement program that occurred from 1998 to 2007. These devices will reach ESL over the next five years. Inventory reports show that 28% of tone devices are obsolete and exceed their ESL.

Performance of both of these types of teleprotection devices has been good. This is one of the reasons why the ESL for the T1 MUX has been extended from 15 years to 20 years.

High Voltage Interface Equipment

Neutralizing transformers ("NT") have been deployed in Hydro One's system since the 1950s. These make up 48% of the HVI equipment that have reached ESL (between 30-50 years, as per Table 12). Other HVI equipment (i.e., optical isolators, isolation transformers) is fairly new. ESL considerations for NTs include degraded insulation, underrated NTs and the overall physical condition of the NT. Some NTs which are oil-filled are also subject to Environment Canada's PCB regulations (SOR/2008-273) however Hydro One has sampled these units and found no PCB content in them.

Microwave Radio Systems

Hydro One's fleet of microwave systems is fairly young. Microwave systems consist of two equipment types based on technology, newer sub-T1 digital microwave systems and T1 digital microwave systems. The majority of sub-T1 digital microwave systems were installed in the last five to six years to provide communication to and from distributed generation customers. None of the sub-T1 microwave systems exceed their ESL. Some T1 microwave systems, however, are experiencing performance as well as maintenance issues where parts are difficult to source because of equipment obsolescence. Of the T1 type microwave systems, 35% of them exceed ESL and are considered obsolete.

Hydro One considers the ESL for radio communication towers to be the same as that for transmission steel structures. Thus, an average ESL of 80 years is used for steel structures assuming they have not yet been re-coated. About 75% of the towers are more than 40 years of age, but none are beyond 80 years. Unlike steel structures, communication tower failures such as a complete tower collapse or a broken (or bent) tower member are very rare.

Provincial Mobile Radio System

The provincial mobile radio system includes 143 base stations and approximately 2,000 radios that connect the OGCC and Richview Backup Control Centre to fixed interim control centres, radio-equipped fleet vehicles and hand-held portable devices spread across Ontario.

The radio technology deployed for the exiting PMRS is technologically obsolete. The equipment is no longer manufactured or supported, and is considered beyond ESL. Hydro One's strategic spares will only last another five years. Maintenance of the PMRS equipment is contracted to an external company for both base stations as well as fleet trucks.

Future Outlook / Need

Telecom technologies typically have a 15-20 year ESL. Many of Hydro One's systems are now approaching their ESL and are facing technological obsolescence. In such cases, the risk of failure increases, and when vendor support ceases, operational sparing becomes challenging.

Hydro One continues to address the sustainment needs of power system telecom assets that exceed their ESL. Technological obsolescence remains the primary focus for the majority of replacement needs. As a result, new technologies are being sought where existing ones are obsolete and no longer meet Hydro One's business requirements. Hydro One is currently:

- Finding a new technology solution to replace the obsolete SONET network as the majority of first generation equipment will exceed ESL in the next three to four years;
- Sustaining and phasing out obsolete and poor performing power system telecom assets that have reached their ESL. This includes ADSS type fibre cables, obsolete PLC systems, teleprotection terminal devices, HVI equipment and microwave radio systems;
- Pursuing a next generation solution for the replacement of PMRS in order to ensure continuity of voice communication services;
- Refining maintenance programs, policies and practices to ensure that they meet the life-cycle optimization as well as reliability requirements as dictated by NERC and NPCC;
- Extending third party IRU contracts where Hydro One ownership of fibre is not economical; and
- Continuing to lease carrier-based services from telecommunication providers to provide PSTS where Hydro One-owned communication facilities are not economical.

In the past, ESL replacements were driven by sustainment capital programs that were based on an asset-centric approach. Going forward, integrated station projects, shield wire replacement projects, and line refurbishment programs will drive Telecom's key asset replacements to meet power system telecom sustainment and development needs. In this way, power system telecom assets can be bundled with other work at a particular station so as to achieve execution efficiencies.

Replacement of SONET Network

Given the obsolescence of both the technology and network equipment on which SONET is built, Hydro One has developed a migration plan towards a modern solution. Implementation in the short and mid-term will begin with the replacement of SONET terminal equipment on Rings 1-9 taking into account other telecom sustainment needs and direction of the strategic expansion of the network.

IP-Based Communications for Teleprotection Applications

Legacy leased analog and digital circuits offered by carriers which are based on carrier time-division multiplexing infrastructure are no longer supported. Moreover, telecom carriers no longer guarantee performance for analog leased circuits due to obsolescence and have indicated that some of these circuits will not be available in the near future.

New IP-based technologies are being investigated by many utilities and regulatory bodies (e.g. NPCC, CIGRE) to migrate existing telecom services to newer IP-based ones. Guidelines and migration paths are being developed. However, it is left up to the individual utility to assess their readiness and establish a migration path which best suits their situation. Hydro One is developing a migration plan to move away from legacy carrier-based leased services. Hydro One also actively monitors industry developments relating to the feasibility assessment and testing of new IP-based technologies.

Expansion of Fibre Optic Cable Infrastructure

The use of fibre optic cable as a communication medium has become a viable alternative for providing reliable high-speed communication between Hydro One stations. There is a foreseen need to expand the footprint of fibre cable infrastructure in order to:

- Meet the growing need of connecting new stations;
- Displace obsolete technologies such as microwave and PLC; and

- Reduce ongoing OM&A costs by moving away from leased services in favour of Hydro One owned facilities.

In the short-term, Hydro One's primary focus is to displace microwave links, leased facilities and third party IRU fibre with OPGW primarily, where economically feasible. Hydro One will also systematically phase out poor performing ADSS cables from its asset base. In the long-term, Hydro One will expand and/or sustain the fibre footprint with 80-100km of new OPGW installed annually.

New Mobile Radio System

The infrastructure sustainment needs of the PMRS are being addressed in the short-term and will continue for the next five to six years with the majority of the work around base station shelters and communication towers. The planned mobile radio replacement project will:

- Examine available technologies such as radio over IP, trunked radio system and integrated solutions to the existing hand-held and in-vehicle units used by field staff;
- Study the technical and economic feasibility of each of the viable technologies, proof of concept, and include a look at future operating costs; and
- Review required infrastructure development to ensure necessary coverage is provided prior to new system deployment.

2.2.1.6 OTHER STATION COMPONENTS

Asset Description / Purpose

Hydro One transmission stations contain a number of other components that are essential to system operation. These components can be broken into three subsections:

- Other Power Equipment;
- Ancillary Equipment; and

- Civil Infrastructure.

Other Power Equipment

Other power equipment assets include HV/MV disconnect switches, capacitor banks, HV/MV instrument transformers, insulators etc.

Table 13 - Summary of Other Power Equipment

Asset	Description
HV/MV Disconnect Switches	High voltage ("HV") and medium voltage ("MV") disconnect switches are used to visually and electrically isolate sections of the transmission system for maintenance, safety, and other operational requirements.
HV/MV Capacitor Banks	Capacitor Banks provide voltage support to maintain power transmission efficiency. These are static devices that provide capacitive compensation into the power system. They are switched in and out of the system based on operating needs.
HV/MV Instrument Transformers	Instrument transformers convert high voltages and currents into proportionately lower values that are used for measurement by protection and control devices. There are three types of instrument transformers: voltage (potential) transformers ("PTs"), capacitive voltage transformers ("CVT") and current transformers ("CTs").

Ancillary Equipment

Ancillary Equipment enable protection and control (P&C) equipment and power equipment to operate as expected. AC/DC station service ("SS") equipment, DC batteries/chargers and high pressure air systems are considered ancillary equipment.

Table 14 - Summary of Ancillary Equipment

Asset	Description
AC/DC station service equipment	AC/DC SS equipment consists of many types of sub-equipment such as AC Station service transformers, AC/DC breakers, AC/DC switches and AC/DC transfer schemes. SS equipment provide DC power to circuit breakers and protection and control equipment as well as

	auxiliary equipment such as fans, pumps, heating, lighting, etc.
DC Batteries and Chargers	All transmission stations have at least one Station DC system to ensure a source of power is available for power equipment operation under all system conditions. Batteries and chargers provide secure DC power within the station. The chargers convert AC into DC to supply the station DC load and charge the batteries. The charged batteries can provide a minimum standard of 8 hours of energy to maintain system operation.
High Pressure Air System	Centralized High-Pressure Air systems ("HPA") are installed at all locations that have ABCB. The system consists of a centralized HPA compressor/dryer plant, an air storage facility, extensive piping and valve arrangements and controls. These systems are being phased out as the ABCBs are phased out as described in TSP Section 2.2.1.2.

Civil Infrastructure

Civil infrastructure consists of the physical structures such as station structures, fences and gates, spill containment, buildings, etc. within the transmission station perimeter.

Table 15 - Summary of Civil Infrastructure

Asset	Description
Station Structures	Station structures are used in stations for mounting electrical equipment such as switches, fuses, breakers, station service transformers, bus, and Intelligent Electronic Devices ("IED"s). Some station structures are wooden, though most are made of steel. The earliest station structures were built in the 1920's.
Fences and Gates	Fences and walls are used to separate live station equipment from the public to maintain public safety. Gates are used as an entry point for Hydro One vehicles, equipment and staff. Most station fences are chain link, though some are wooden.
Spill Containment Systems	Spill containment systems are present in stations that pose a possible detrimental effect to the environment if a spill were to occur (e.g. near river, pond). These spill containment systems collect transformer oil in the event of a transformer tank rupture.
Security and Fire Protection	The Security and Fire Protection asset class includes systems that protect transmission station facilities from fire, break-ins and vandalism. The security systems include additional measures ranging from conventional door control security systems to video surveillance facilities. The fire protection systems are primarily of two types: those associated with buildings and those associated with equipment.

Asset	Description
Station Site and Yard	Station site and yard are site elements including station drainage and geotechnical systems, vegetation/weed management inside the station, gravel, garbage, etc.

Asset Conditions / Demographics

Hydro One determines the overall condition of Other Station Components by considering all of the significant factors and relevant degradation processes associated with each individual asset group. Table 16 summarizes the number of Other Station Components that are present in Hydro One's transmission stations.

Table 16 – Number of Other Station Components

Asset Type	Quantity
Other Power Equipment	
HV/MV disconnect Switch	14,331
HV/MV Instrument Transformer	8,130
HV/MV Capacitor Banks	370
Ancillary Equipment	
DC Batteries & Chargers	1,425
High Pressure Air System	482
AC/DC Station Service Eq.	1,060
Civil and Infrastructure	
Building	823
Infrastructure	251
Fences and Gates	391
Spill Containment	420
Fire and Security system	43
Site and Yard	637

Data current as of 31 December 2018

Other Power Equipment

- HV/MV Disconnect Switches

The disconnect switch demographic has been presented in Figure 17. Approximately 46% of the HV and MV switches are over 40 years old, with an ESL ranging between 40 to 50 years. Replacements are recommended once the equipment reaches ESL and Hydro One has completed condition assessments by analyzing data from maintenance records to inform the need for replacement. Currently, 25% of the switch fleet is responsible for the majority of recorded defect reports. Out of the 25%, approximately half are beyond their ESL. Hydro One monitors the condition of these assets via preventive maintenance plans, visual inspections and thermo vision. The results from monitoring help identify the problems to be repaired or replaced in a timely manner. Switches require regular maintenance and corrective actions to keep the fleet in operating condition.

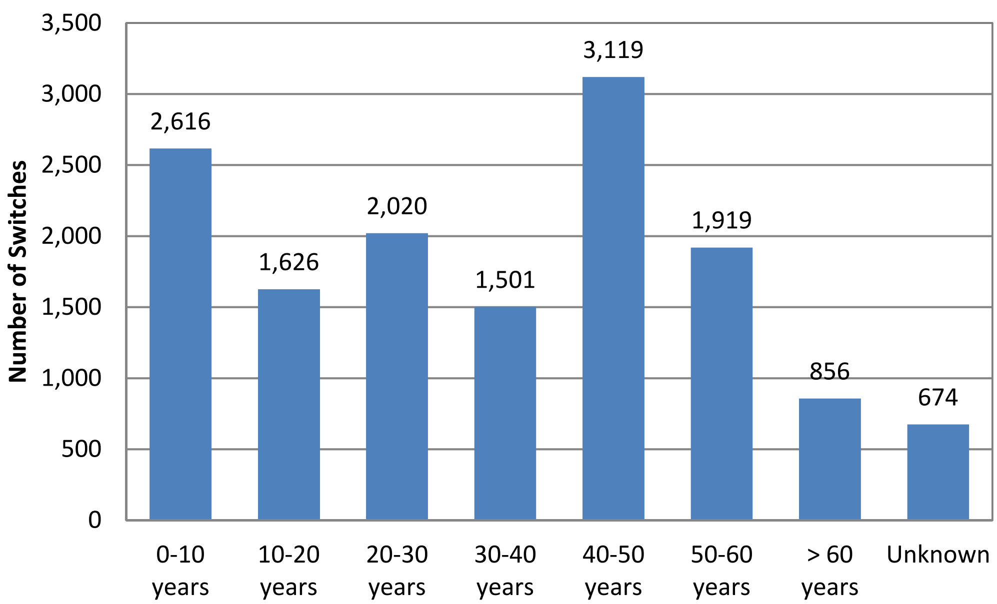

Figure 17 - Demographics for HV and MV Disconnect Switches

- HV/MV Capacitor Banks

Hydro One manages approximately 370 capacitor banks. Approximately 75% of the capacitors were installed within the last 20 years. Capacitors are closely monitored for signs of deterioration and Hydro One focuses on replacing these capacitors in a timely and efficient manner.

- HV/MV Instrument Transformers

Hydro One manages more than 8,000 free-standing instrument transformers out of which approximately 5,000 are High Voltage Instrument Transformers ("HVIT") and 3,000 are Medium Voltage Instrument Transformers ("MVIT"). The fleet of HVITs and MVITs are used for various purposes, including to measure voltage and current or to meter usage. Instrument transformers that are beyond their ESL and use oil as an insulating medium are assessed for replacement in order to avoid oil leak and increasing maintenance costs. Through regular maintenance, Hydro One is able to identify and address the issues affecting these assets, such as leaks, gassing, wrong turn ratios, etc.

Ancillary Equipment

- AC/DC Station Service

Hydro One manages more than 1,000 AC/DC SS equipment devices. ESL varies in AC/DC SS as it is comprised of various components such as AC switches, transfer schemes, AC breakers but on average 40 years is considered the appropriate ESL at Hydro One. Through regular inspections, the company is able to identify defects to be either replaced or repaired.

- DC Batteries and Chargers

Hydro One currently manages 385 battery banks and 387 chargers supplying protection and control and other station ancillary DC services. About 12% of station batteries have exceeded their ESL which is 20 years and 15% of chargers have exceeded their ESL which is 30 years. Hydro One maintains, monitors, and proactively replaces this equipment to maintain redundancy as coincident battery failures can have severe consequences on power system safety and reliability.

- High Pressure Air System

Hydro One currently manages HPA systems at 10 transmission stations, including 61 compressors, 53 dryers, 300 air receivers, and other related HPA ancillary systems. These assets generally experience minor leaks from the compressor, dryers or air lines. Leaks or failures in the HPA system can result in the removal of high voltage ABCBs from service until repairs can be completed. ABCBs are primarily installed at bulk transmission stations, and are critical in supporting bulk power flows within Ontario and through international tie lines. Through the replacement of the ABCB fleet, the associated HPA system will be removed as it will no longer be needed.

Civil Infrastructure

Civil Infrastructure assets are comprised of station drainage systems, yard surface /subsurface, access roads, structural footings, foundations, perimeter fencing, fire detection/protection, yard lighting and cable trenches. These systems provide infrastructure and support services to station equipment and station environmental systems. Asset condition is determined by monthly visual inspections and resulting deficiencies are a measure of the overall condition.

Foundations, footings, spill containment and asphalt roads can heave and crack due to freeze/thaw cycling. Drainage systems are made of clay piping and can deteriorate and/or collapse as they age. Station fences and gates are damaged or otherwise compromised by thieves seeking to gain access to yards to steal copper grounds. Theft creates additional safety hazards and potential power quality issues.

Future Outlook / Need

Any HVIT and MVIT containing PCB contaminated oil will be replaced prior to 2025 to meet compliance with federal regulatory requirements. In addition to these replacements, it is expected that a further 800 free-standing CTs will be removed in conjunction with the ABCB replacements as most of the CTs on newer breakers are installed around the breaker bushing.

The battery replacement program will target Valve Regulated Lead Acid (“VRLA”) batteries as Hydro One has experienced the coincident failure of two VRLA batteries. The loss of two VRLA batteries can result in inoperative protection and control equipment that creates a safety and reliability risk for the power system and employees. Cost effectiveness is another factor considered in the decision to replace or repair DC battery systems.

The timing of HPA system decommissioning is driven by ABCB replacements. By 2025, all HPA systems are expected to be removed from the system. The HPA systems will continue to be maintained due to their critical function of supporting the ABCB fleet where it is cost effective.

2.2.2 (5.3.2 B, C, D) ASSET COMPONENT INFORMATION – TRANSMISSION LINES

Transmission lines are used to transmit electric power, via network and radial circuits, to either direct transmission customers or to transformation points for distribution to retail customers. Transmission line major components include overhead conductors, underground cables, structures, foundations, insulators, and shieldwires.

2.2.2.1 OVERHEAD CONDUCTORS

Asset Description / Purpose

The conductor of an overhead transmission line is the asset responsible for transporting electricity between system nodes. Over 99% of Hydro One's transmission system is comprised of overhead power lines as opposed to underground cables. The conductor is the single largest and most vulnerable component of the transmission line system. Close to 98% of Hydro One's overhead conductor fleet utilises aluminum conductor steel reinforced ("ACSR") conductor types; with copper, aluminum and aluminum conductor steel supported ("ACSS") types making up the balance.

Asset Condition / Demographics

Demographics

Following a recent analytical study conducted the Electric Power Research Institute ("EPRI") Hydro One has changed ESL for its ACSR conductor type from 70 years to 90 years. Further details on this study are available in Section 1.4. The actual life span of each conductor can vary between 50 and 120 years because numerous uncontrollable variables affect conductor deterioration, including manufacturing material quality, location, orientation, local atmospheric pollution levels, weather cycles and stringing tension. Presently, Hydro One's conductor fleet has an average age of 55 years.

Currently, about 5% of the overhead conductor fleet has reached or exceeded its ESL of 90 years. Table 17 below summarizes the demographic profile of the overhead conductor fleet. Without any further replacements, the percentage of conductors exceeding ESL will increase to about 13% by 2024.

Table 17 - Overhead Conductor Demographics

Conductor Type	Circuit km in Service	Average Age (Years)	ESL (Years)	Beyond ESL	Beyond ESL 2024	Beyond ESL 2029
ACSR	28,437	54	90	876	3,125	3,988
Copper	512	97	70	512	512	512
Aluminum	21	89	100	0	15	15
ACSS	137	26	N/A*	0	0	0
Total	**29,107**	**55**		**1,389**	**3,653**	**4,516**

** Relatively new conductor type to Hydro One, limited installation, ESL to be established*

Condition

Hydro One operates a condition assessment program that identifies conductors that are beyond 50 years as candidates for assessment to determine the condition through testing. Based on Hydro One's operating experience, conductors below 50 years of age are considered low risk and have a small likelihood of being in a deteriorated condition.

By the end of 2024, about 13% or 3,653 circuit km of the conductor fleet will reach or exceed its ESL. Condition assessment results indicate that about 13% or 3,680 circuit km of the conductor fleet is known to be in high risk conditions, as shown in Figure 18 below. This includes ACSR conductors verified to be in poor condition through testing, and copper conductors, many of which suffer from damage caused by lightning strikes, mechanical strength loss and can no longer be repaired due to obsolete repair components.

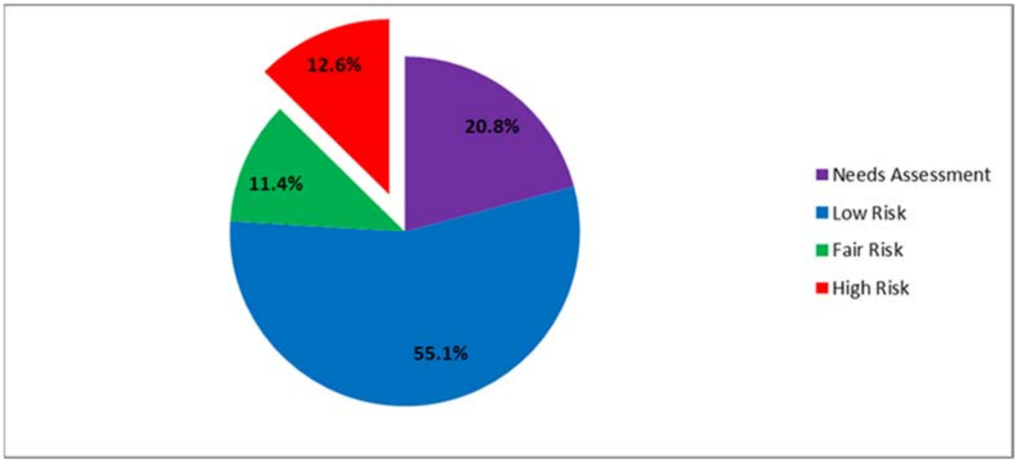

Figure 18 - Distribution of Overhead Conductor Condition

Performance

Failure of an overhead conductor can have severe consequences both in terms of reliability and safety. The number of forced outages due to conductor failures has improved over the past ten years while the outage duration has been relatively stable over the same period with the exception of abnormalities in 2009 and 2015, as outlined in Figure 19 and Figure 20. In 2009, circuits B10H/B20H required an extended forced outage to accommodate an emergency conductor replacement.[8] In 2015, an extended forced outage was required to replace twelve misaligned conductor sleeves along circuit A6R.

Hydro One has made some progress in addressing the condition assessment backlog for conductors. Relative to the EB-2016-0160 filing, the percentage of conductors requiring assessment has decreased from 31% to 21%. While many of the circuits assessed were found to be in low risk condition, the proportion of high risk conductors increased from 9% to 13% as confirmed by testing. As more conductors deteriorate and fall into the high-risk category, the risk of failure is also expected to increase, which is likely to

[8] B10H/B20H circuits are self-damping conductors that required replacement due to mechanical failures (rather than due to age-related deterioration).

translate into more frequent conductor-related outages and/or prolonged outage durations (i.e., where the line is a radial supply). While age is not the determining factor for conductor replacement decisions, it is nevertheless a useful proxy in relation to asset condition and associated risk of failure, which are confirmed through actual assessment and testing. Given the drastic increase in conductors reaching or exceeding their ESL from now to 2024 (see Table 17 above), coupled with testing results to date showing an increase in the proportion of high risk conductors, Hydro One has to proactively replace conductors in a well-planned and paced manner so as to ensure the ongoing safe and reliable operations of Ontario's BES. As illustrated in Figure 19 and Figure 20, there have been significant spikes in outage frequency and duration in certain years, which impact the overall trend line and simply cannot be predicted with any degree of accuracy. In light of the above considerations, despite the overall downward trend of forced outage frequency and duration relating to overhead conductors, it would not be prudent to wait until noticeable reliability degradations materialize before undertaking the required investments.

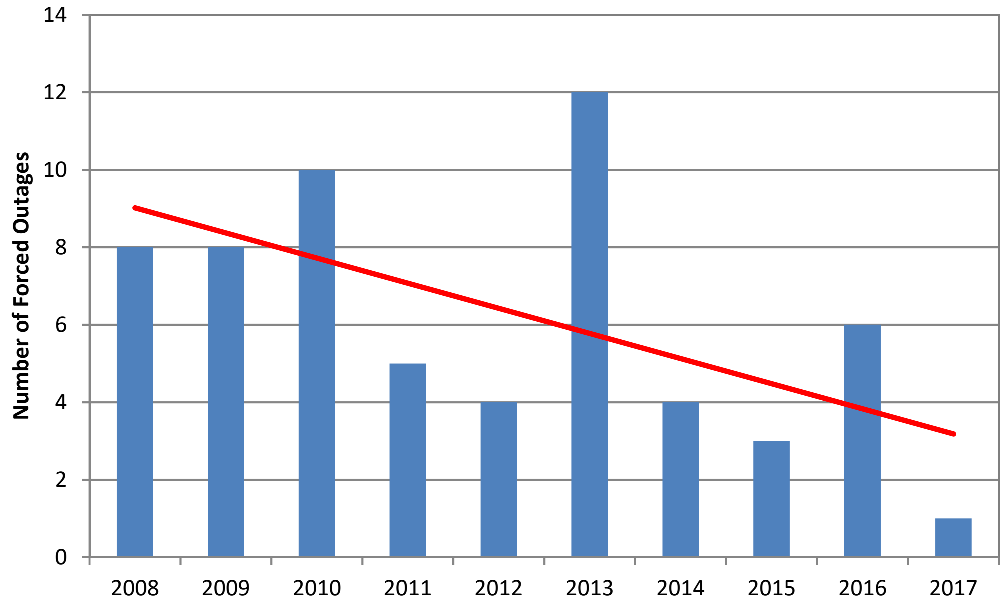

Figure 19 - Overhead Conductor Forced Outage Frequency

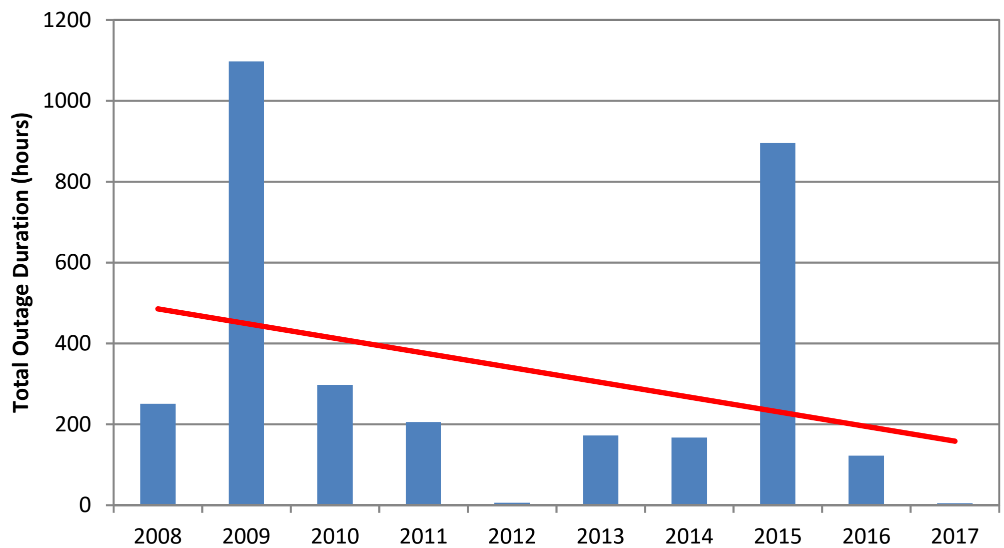

Figure 20 - Overhead Conductor Forced Outage Duration

Future Outlook / Need

The number of conductors beyond ESL is increasing, despite a planned increased level of replacements when compared to historical levels. If this issue is not addressed in a proactive and timely manner, system and customer reliability and safety will be placed at risk. Consequently, an increase in planned replacements is required to maintain acceptable fleet condition and performance and to avoid a drastic spike in investments that would otherwise be required in the future as a result of deferred replacements. However, not all conductors beyond ESL require replacement, as many conductors beyond ESL have been found to be in good or fair condition. Hydro One has increased the condition assessment program in order to accurately assess the conductor fleet that has yet to be reviewed (21% of the fleet) and thereby effectively identify conductors requiring replacement.

Hydro One is currently evaluating the C-corr technology developed by EPRI. This device is a non-contact tool that can be operated from the ground and can be used to assess the condition of conductors with steel cores by analyzing the discolouration signatures between the aluminum layers. C-corr technology can potentially reduce the cost of conductor condition assessment if proven to be accurate. Hydro One will re-evaluate implementation of this technology as test results become available to prove its reliability and cost-benefit values.

2.2.2.2 UNDERGROUND CABLES

Asset Description / Purpose

Underground transmission line cable systems are typically used to link portions of the overhead network or connect substations. They are mainly used in urban areas where it is either impossible or extremely difficult to build overhead transmission lines due to urban density, legal, environmental or safety issues.

Cable systems consist of the main cable and ancillary equipment (i.e. accessories) used to support cable operation. Cables are classified into the following three types; (i) Low-Pressure Liquid-Filled ("LPLF"); (ii) High-Pressure Liquid-Filled ("HPLF"); and (iii) Extruded Cross-linked Polyethylene ("XLPE"). LPLF and HPLF cables use oil as a dielectric (insulation) medium while XLPE cables utilize oil-free solid-dielectric insulation.

Asset Condition / Demographics

Demographics

There are approximately 264 circuit km of in-service underground transmission line cables in the system rated at either 115 kV or 230 kV. The majority of Hydro One's underground transmission system (88%) is comprised of oil-filled cables (i.e. LPLF and HPLF), with the remainder (12%) being XLPE. All new underground cable installations and replacements generally use XLPE, which is currently the most widely used cable technology and eliminates negative environmental impacts associated with oil leaks.

Hydro One's underground cable fleet has an average age of 37 years with an ESL of 70 years for LPLF and HPLF cables and 50 years for XLPE cables.[9] A demographics summary of the cable population is shown in Table 18. This data is as of 2018 year-end and does not include planned replacement for 2019 and beyond.

[9] Hydro One has previously used an ESL of 50 years for LPLF and HPLF cables. The ESL has been increased to 70 based on an EPRI study, which is discussed in Section 1.4.

Table 18: Underground Cable Demographics

Cable Type	Circuit kms in Service	Average Age (Years)	ESL (Years)	Beyond ESL	Beyond ESL 2024	Beyond ESL 2029
LPLF	60	52	70	0	2	15
HPLF	173	38	70	0	2	2
XLPE	31	6	50	0	0	0
Total	**264**	**37**	**-**	**0**	**4**	**17**

Condition

Cable condition assessment is based on a variety of quantitative test factors applicable to the cable type. Condition assessment is described in more detail in Section 2.3.2.2. Routine preventive maintenance and more intrusive diagnostic tests have shown that many underground cables are in good operating condition and, as such, have a low risk profile. Overall, Hydro One's underground cable population is in good condition. The majority of cables identified as high-risk have been planned for replacement by 2025. Figure 21 illustrates the breakdown of cable assets by assigned risk ratings.

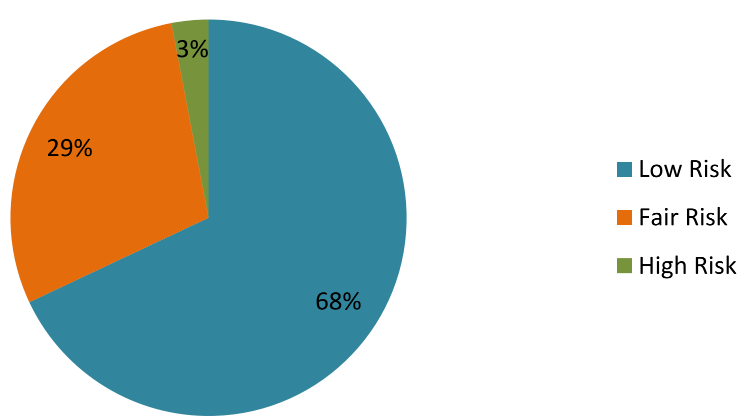

Figure 21 - Cable Asset Condition Summary

Performance

Cable outages are infrequent and normally do not result in delivery point interruptions. Most delivery points are connected to two circuits for redundancy and have a network configuration. However, an outage resulting from an underground cable failure can be lengthy in duration, with an average repair time of approximately 42 days. The frequency and duration of underground cable caused circuit outages from 2008 through 2017 is summarized in Figure 22 and Figure 23 below. Due to the relatively small number of outages, it is not possible to infer a statistically significant performance trend.

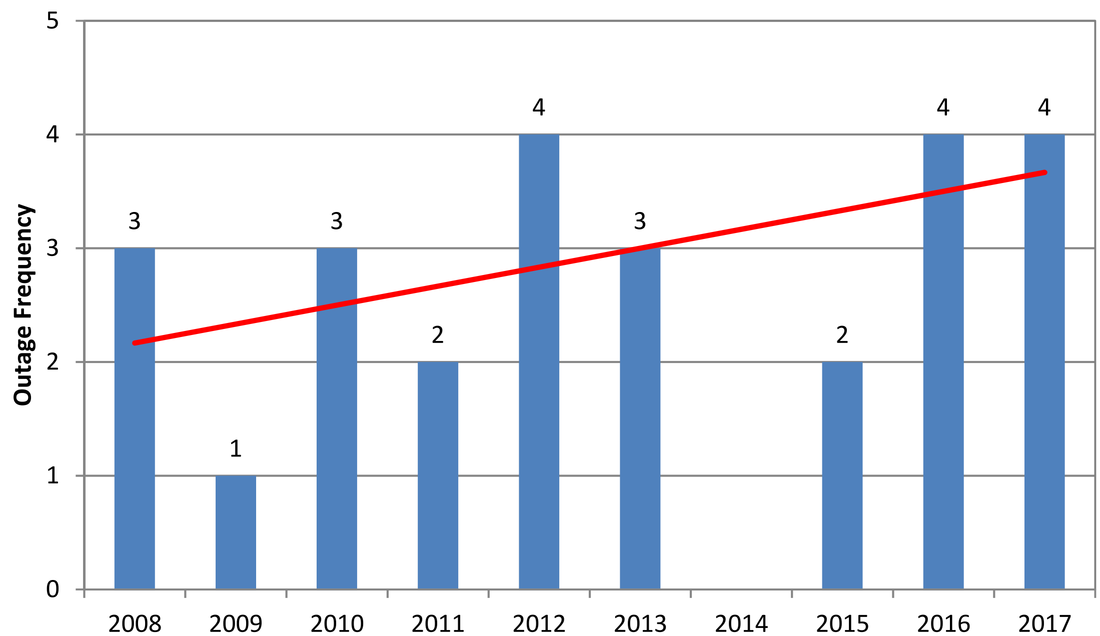

Figure 22 - Cable Outage Frequency

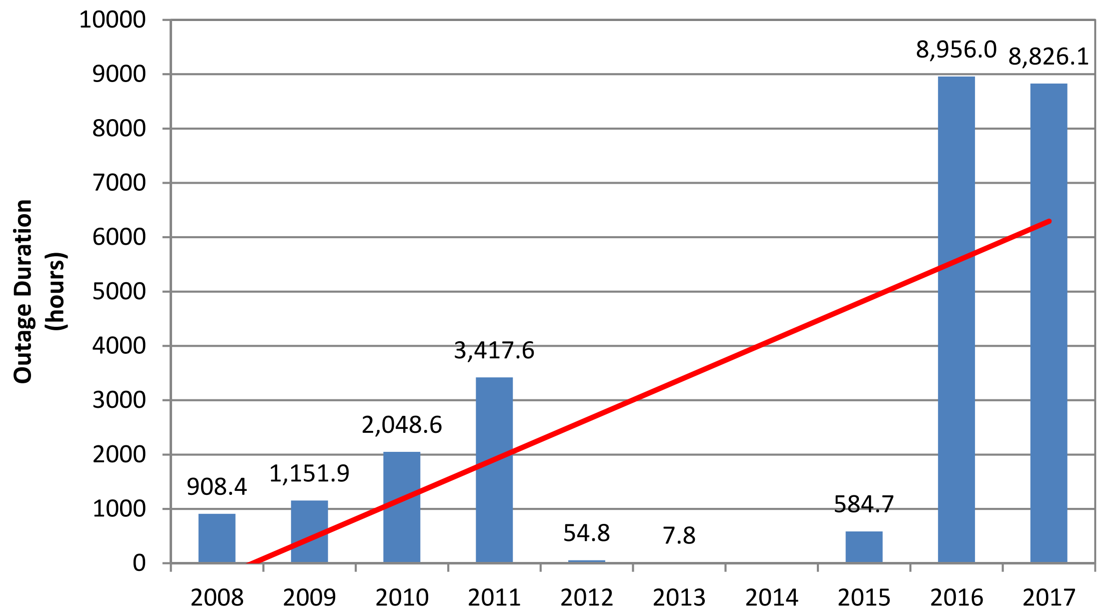

Figure 23 - Cable Outage Duration

While the number of outages in 2016 and 2017 are not unusually high, the high outage durations in those years were caused by a joint failure on circuit H11L that allowed moisture to permeate the paper insulation, leading to cable failure. The repair time was significant due to the material lead time and excavation required.

Future Outlook / Need

The majority of Hydro One's cable assets are in good condition. This is due to rigorous maintenance programs and operation practices (i.e. operating cables below their maximum thermal rating and insulating 115 kV cables to 230 kV (post-1970)). However, if historical maintenance levels are not continued, outage frequency and duration are expected to increase in the long-term.

There is an industry shift away from the use of LPLF and HPLF to XLPE cable systems. As such, manufacturers have been reducing production and support for oil-filled cables.

To mitigate this obsolescence risk, Hydro One manages a spare inventory of LPLF and HPLF cables and ancillary equipment. There is also a significant environmental risk in the event of a HPLF or LPLF cable breach. Breaches are not only caused by failed or degraded components but also by dig-ins from unauthorized excavation, which can result in the discharge of large volumes of oil into the surrounding environment.

Hydro One plans to integrate distributed temperature sensing ("DTS") systems where needed and feasible. Cable operating ampacity can change over time due to external factors leading to cable overheating and damage thereby reducing its useful life. These systems enable real-time temperature monitoring and thermal optimization to manage ampacity and extend cable ESL.

For new construction and replacement, XLPE cables are used to eliminate environmental and obsolescence risks. LPLF and HPLF cables may be considered for special applications such as repairs and the relocation of short circuit lengths.

2.2.2.3 STRUCTURES & FOUNDATIONS

Asset Description / Purpose

Steel Structures

Steel structures elevate transmission lines above the ground, providing clearance from ground objects and separation between the circuit conductors and other line components. These structures have various designs, sizes and configurations and support transmission circuits from 115 kV to 500 kV.

Wood Pole Structures

Wood poles serve the same purpose as steel structures.The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access. Similar to steel structures, wood pole structures have various designs, sizes and configurations and support transmission circuits from 115 kV to 230 kV.

Foundations

Foundations support and anchor transmission structures to the ground and enable the structures to withstand the weight of the structure itself, attached components and weather related external forces such as wind and ice. There are three dominant foundation types in Hydro One's transmission system: cast-in concrete footings, steel grillage footings, and steel anchors.

Asset Condition / Demographics

Demographics – Steel Structures

Hydro One has approximately 52,000 steel structures including 1,950 steel poles supporting 115kV to 500kV transmission lines. The demographics of the steel structure population are outlined in Table 19 below. Current steel structures have an average age of 58 years and an ESL of 80 years if they are not re-coated.

Table 19 - Steel Structure Demographics

	Quantity	Average Age	ESL (Years)	Beyond ESL currently	Beyond ESL 2024	Beyond ESL 2029
Steel Towers in Light Corrosion Zones	37,300	59	80	6,605	8,005	9,510
Steel Towers In Heavy Corrosion Zones	13,000	59	80	3,000	3,550	4,150
Steel Poles	1,950	33	80	85	95	150
Total	**52,250**	**58**	**80**	**9,690**	**11,650**	**13,810**

As explained in the following section, Hydro One's current strategy is to focus on structures in very high corrosion zones (i.e. C5[10] zones). The demographics of these structures are shown in Figure 24.

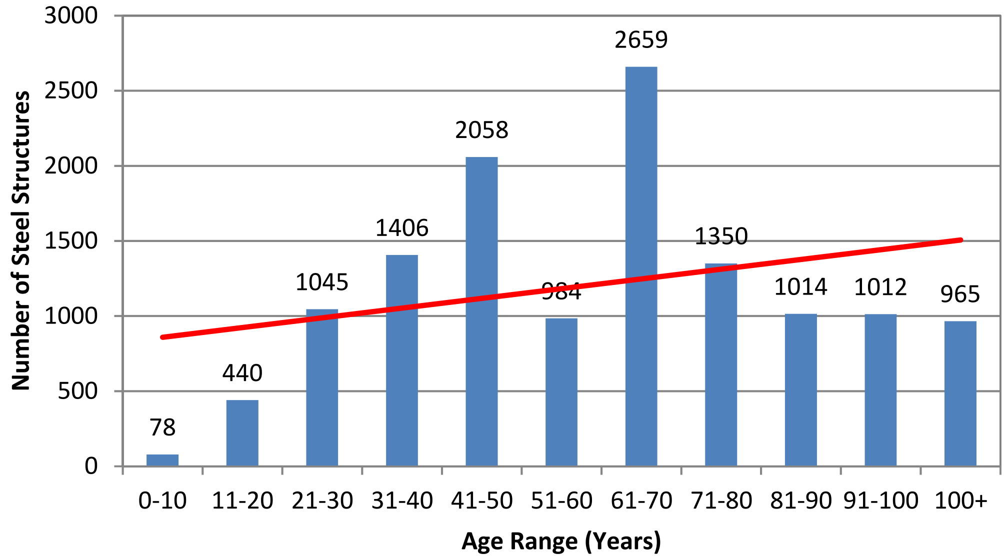

Figure 24 - Demographics of Steel Structure Fleet in Very High Corrosion Zones

Condition – Steel Structures

The service life of a steel structure primarily depends on the condition of its Hot Dip Galvanizing ("HDG") coating. Once this protective zinc layer is lost, the structure's carbon steel is exposed and the corrosion rate could increase by a factor of 8 to 10. This will result in the loss of structural strength, ultimately requiring replacement.

There are approximately 13,000 steel towers located in very high corrosion zones with 7,500 of them currently meeting tower coating criteria.

[10] Based on the ISO 9223, typical atmospheric environments are categorized from C1 through to C5, with C1 exhibiting very low in corrosivity, and C5 exhibiting very high corrosivity.

Based on the current assessment, 6% of Hydro One's steel structures have been re-coated, 8% require major refurbishment or replacement, and 14% require coating that will be addressed in the steel structure coating program. Seventy-two percent (72%) of the structures are currently in good condition and are not expected to require any maintenance in the near future. This assessment is continuously reviewed and updated as more structures are assessed and inspected. Based on the current business plan, condition assessments will be performed on approximately 1,500 towers annually in heavy corrosion zones.

Performance – Steel Structures

Forced outages for steel structures represent the number of times an outage is caused by a steel structure failure such as complete tower collapse, or a broken (or bent) tower member. It excludes forced outages caused by catastrophic damage (i.e. caused by transmission lines being struck by tornado, aircraft, truck, etc.).

The number of forced outages due to steel structure failures has shown a slight downward trend over the past ten years (see Figure 25), while outage duration has been relatively stable except for 2011 (see Figure 26). In 2011, there were multiple tower collapses on two different tower lines due to high wind. 2016 also saw a severe weather event, which caused the collapse of several towers and consequently a significant outage.

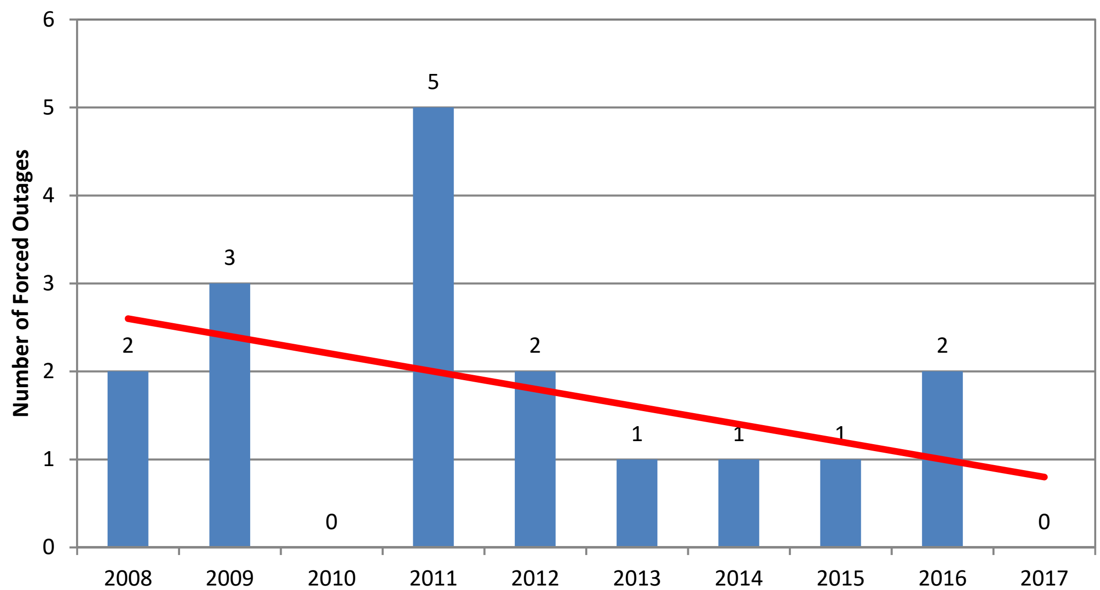

Figure 25 - Forced Outages Frequency due to Steel Structure Failures

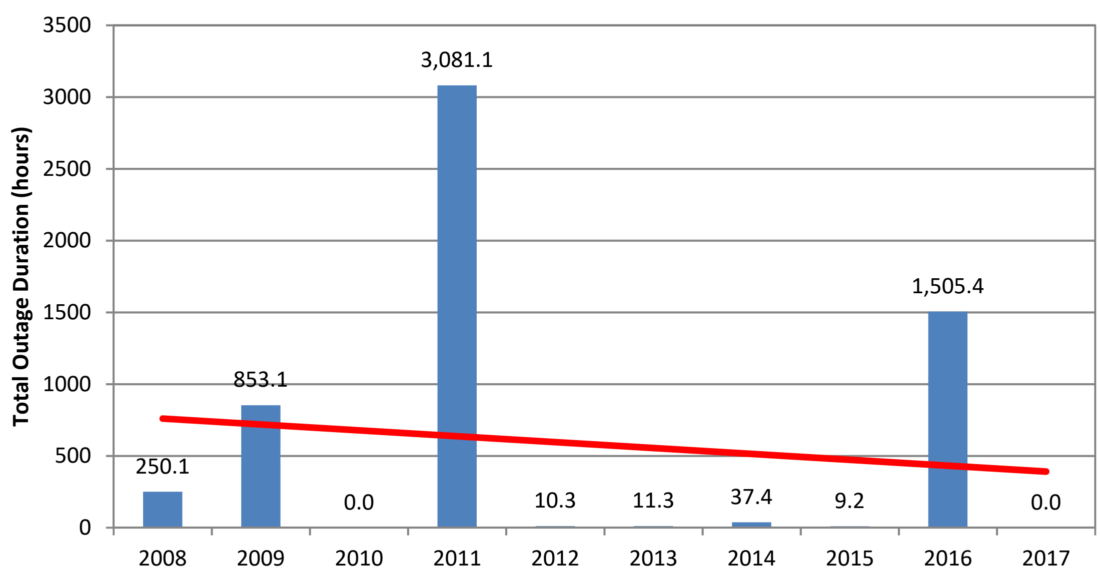

Figure 26 - Forced Outage Duration due to Steel Structure Failures

Demographics – Wood Pole Structures

Hydro One has approximately 42,000 wood pole structures in its transmission system. The average age of the wood pole fleet is 41 years and 34% of the wood poles are beyond their ESL of 50 years. The demographics of the wood pole population are outlined in Table 20.

Table 20 - Wood Pole Structure Demographics

Wood Structure	Quantity	Average Age	ESL (Years)	Beyond ESL currently	Beyond ESL 2024	Beyond ESL 2029
Total	42,000	41	50	14,400	15,100	17,940

Condition – Wood Pole Structures

Wood structures deteriorate over time. The rate of deterioration depends on many factors including location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location. Due to the nature of the design, the wood cross-arm tends to be the weak link and is typically the primary cause of failure.

Based on wood pole assessments, 13% of Hydro One’s wood pole population requires replacement, as illustrated in Figure 27. These poor condition poles typically exhibit woodpecker damage, mechanical damage or insect damage. Approximately 45% of the wood pole population needs to be assessed to determine its condition, while about 42% of the population is either in good condition or not eligible for assessment (i.e. younger than 25 years).

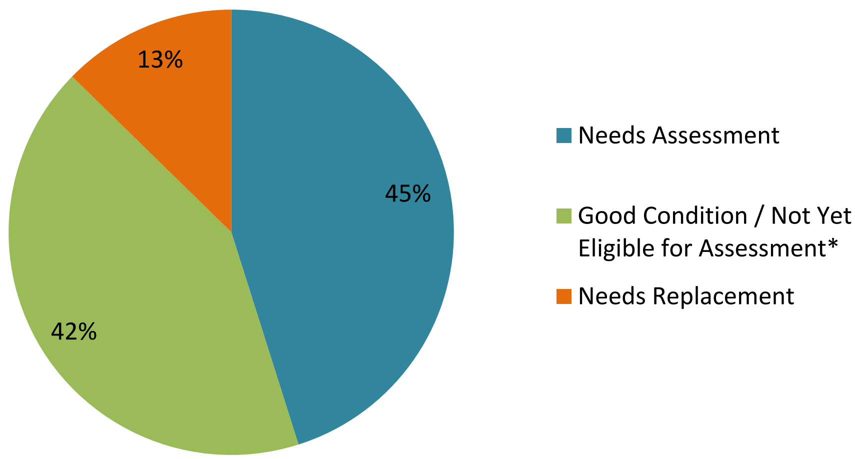

Figure 27 - Wood Pole Fleet Condition Status

Performance – Wood Pole Structures

The majority of transmission wood pole structures are located in Northern Ontario and many of these structures support radial circuits. As a result, a wood pole or cross-arm failure can often directly result in a customer outage. Many of these northern wood pole circuits feed major industrial customers. Without an adequate supply of power, these customers may be forced to shut down until power is restored. Such an event can add significant cost to a customer's operations.

As shown in Figure 28, the number of forced outages due to wood pole structure failures has increased over the past ten years. Wood pole failure is the result of a combination of factors, such as pole condition, weather condition, physical loading, and the local environment. Wood poles are a natural product that despite treatment, have some quality inconsistencies in each pole, which can result in an unpredictable failure under certain conditions.

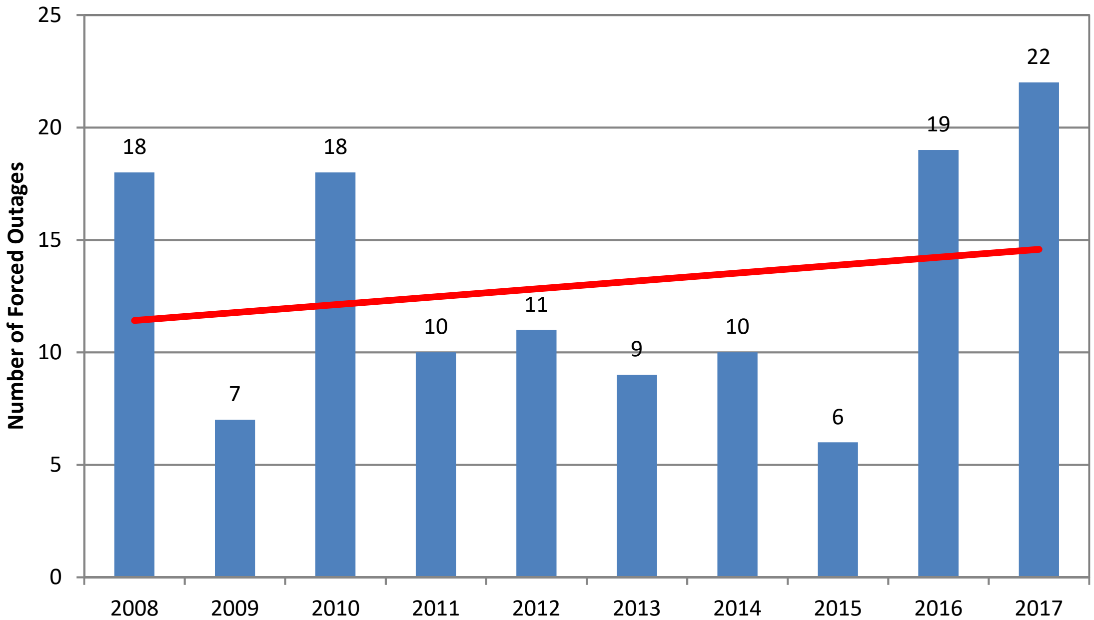

Figure 28: Forced Outage Frequency Due to Wood Pole Failures

As shown in Figure 29 the forced outage duration due to wood pole failures has generally improved over the past ten years. The relatively high outage incidences and durations in 2016 and 2017 may point to the start of an upward trend (although a few more years of data would be needed to be certain). Hydro One will continue to monitor the condition of its wood pole feet and implement the necessary steps to mitigate any emerging trend.

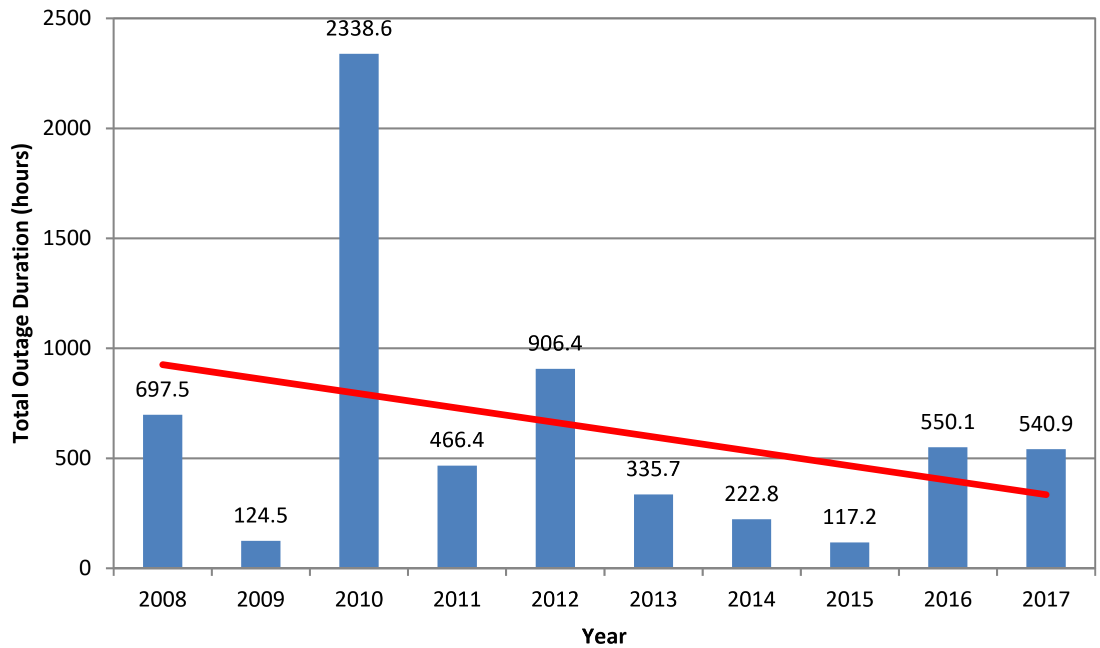

Figure 29: Forced Outage Duration due to Wood Pole Failures

<u>Demographics – Foundations</u>

Hydro One's transmission system contains approximately 52,000 steel structures with foundations made of either concrete or steel. Approximately 32,000 foundations are steel grillage and the other 20,000 foundations are cast in concrete (auger or pad and pier). The reason for the change was the construction efficiency and asset durability of concrete auger type foundations plus more restrictive environmental protection regulations. All grillage foundations are or will be 50 years or older during the course of the next five years and will need to be assessed through the Assess, Clean and Coat program. Table 21 shows the demographics of all foundations:

Table 21 - Foundation Demographics

Foundation Type	Quantity	Average Age (Years)	ESL (Years)	Beyond ESL	Beyond ESL 2024	Beyond ESL 2029
Cast-in Concrete Footings	20,000	33	100+	0	0	0
Steel Grillage Footings	32,000	74	80	10,235	12,185	14,360
Steel Anchors	3,500	46	80	0	0	0
Total	**55,500**	**57**	**-**	**10, 235**	**12,185**	**14,360**

Conditions – Foundations

The Transmission Lines Foundation Assess, Clean, Coat and Repair Programs consist of two components. The first component, Assess, Clean and Coat, is intended to assess the condition of transmission tower foundations. Each tower is assessed and is either coated immediately or scheduled for future repairs. The status of foundation condition assessments is shown in Figure 30. The decision to coat or repair depends on the severity of corrosion (metal loss) that is found and the complexity of potential repairs (some minor repairs can be executed under this activity). The second component of the program, Foundation Repair, is designed to complete more complex repairs and/or the replacement of foundations identified during previous assessment activities.

If a line is scheduled to be refurbished, then activities forming part of the Assess, Clean, Coat and Repair activities will occur as a part of the refurbishment projects. Based on inspection results, where severe corrosion has caused significant strength reduction, the foundation will be identified as a candidate for repair or replacement. Hydro One is currently focusing on grillage footings and anchors due to their age and configuration which sustain a higher incidence of corrosion. Concrete footings are younger and are not displaying signs of corrosion. The current plan is to assess/clean/coat approximately 800 grillage foundations in 2020 and 1600 foundations per year from 2021-2024.

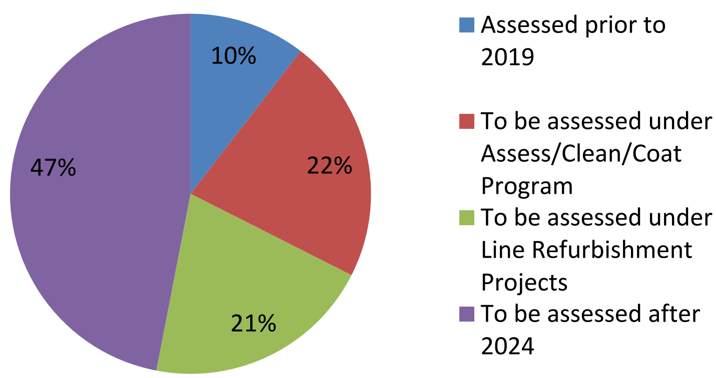

Figure 30 - Steel Grillage Foundation Condition Assessment Status

Future Outlook / Need

Steel Structures

With the current condition of the steel structures and the demographics of the fleet, it is expected that increased capital investments will be required to maintain the integrity of the steel structure fleet in order to avoid future failures and outages.

Wood Pole Structures

Hydro One will continue to replace wood poles that have failed condition assessments. Although failures in this population can occur at any time, the likelihood increases during severe weather events.

Hydro One has started using composite pole technology to replace wood poles. Composite pole technology has the potential to reduce long-term maintenance costs. Currently, 25% of the poles replaced in any given year are with composite material, which nonetheless only accounts for less than 1% of the pole structure fleet. The gradual installation of composite poles will allow for the evaluation of this technology in Hydro One's system.

Foundations

There are very few cases where concrete foundation deteriorations have occurred in Hydro One's system. As a result, current Hydro One programs related to foundations focus on steel grillages and steel anchors installed before 1970. These steel footings are at least 50 years old and recent inspection results have shown a higher incidence of degradation.

2.2.2.4 INSULATORS

Asset Description / Purpose

Transmission line insulators are an integral component of the transmission system. Transmission line insulators are required to perform two basic functions. They must provide mechanical support for overhead conductors and they must provide electrical isolation between the energized conductors they support and the grounded towers to which they are attached. A typical transmission line insulator is shown in Figure 31 below. A summary of insulator classifications can be found in Table 22 below.

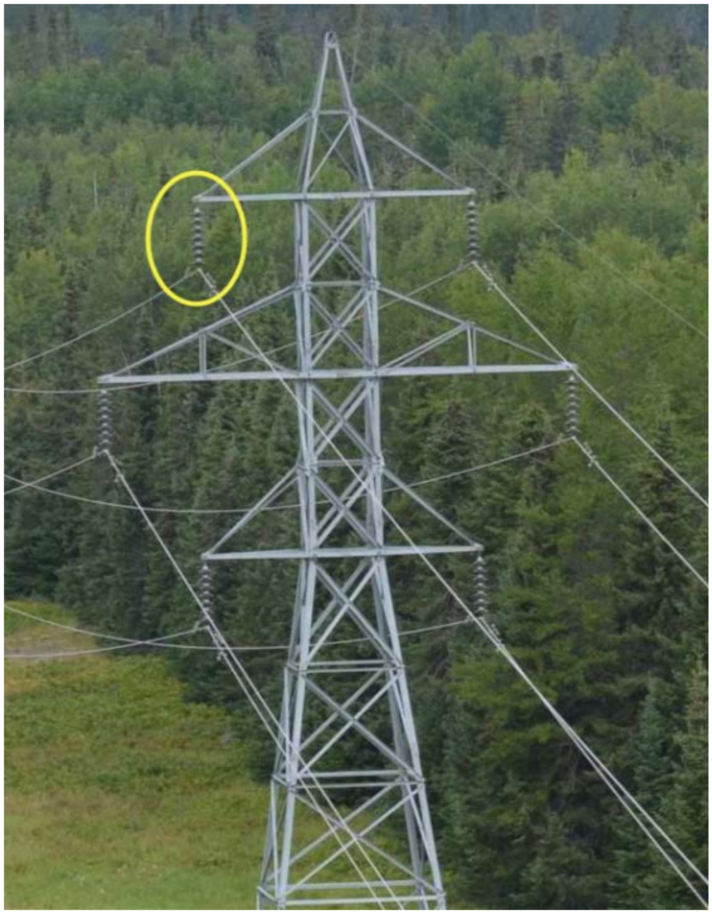

Figure 31 Transmission Line Insulator

Table 22 – Insulator Material Classifications

Type		Vintage	Voltage (kV)	Description
Porcelain		1910+	115, 230, 500	Porcelain insulators are the oldest and most common insulator type used by Hydro One. They are projected to last for the life of the line; however, isolated failures do occur and there are known issues affecting specific vintages.
Glass		Mid-1980s+	115, 230, 500	Hydro One began installing glass insulators in the mid-1980s as an alternative to defective porcelain. They are projected to last for the life of the line; however, isolated failures do occur.
Polymer		Mid-1980s+	115, 230	Polymer insulators were developed as an alternative to porcelain and glass. Their material properties entail the following benefits: • Lighter-weight (making them easier to install); • Vandalism resistance (less susceptible to mechanical damage); and, • Better contamination performance (less likely to flashover in contaminated environments).

Asset Condition / Demographics

Demographics

There are approximately 437,000 insulator strings in Hydro One's overhead transmission network. The percentage of insulators by material type is shown in Figure 32.

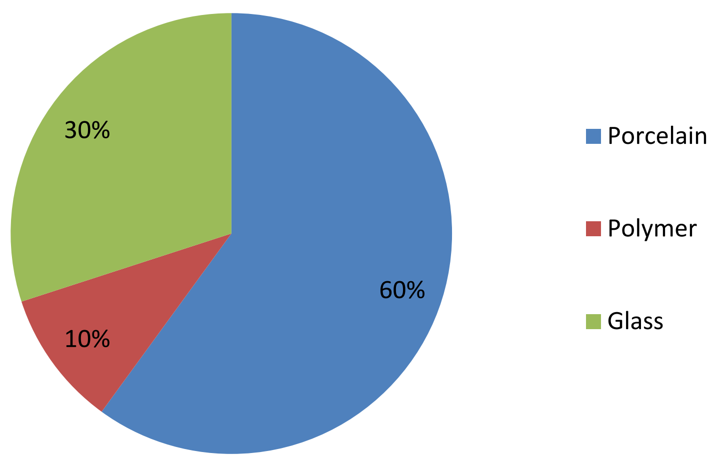

Figure 32 – Percentage of Insulators by Material

Demographics are not a driving factor for the replacement of porcelain or glass insulators since insulators are generally expected to last for the life of the transmission line and significant condition degradation is not expected to occur over time. Replacement is normally done as part of other work programs (e.g. line refurbishment). Program specific insulator replacement work targets strings that have prematurely reached their EOL due to one-off failures (e.g. broken shells), manufacturing defects, improper functionality or poor design.

Hydro One uses polymer insulators on the 115 kV and 230 kV transmission system. Polymer insulators have an ESL of 30 years and, due to their material properties, degrade with age. First-generation polymers installed in the mid-1980s are approaching the end of their ESL and will need to be evaluated for replacement. First-generation polymers are more problematic when compared to more recent generations. When older polymer insulators were designed and manufactured, the long-term effects of electric fields were not well understood which caused unexpected polymer degradation. Newer generations use modified designs and refined manufacturing techniques.

Condition

Quality porcelain and glass insulators have low failure rates and are not expected to reach EOL before the conductor. However, porcelain insulators manufactured by Canadian Ohio Brass ("COB") and Canadian Porcelain ("CP") between 1965 and 1982 suffer from a phenomenon known as cement expansion or cement growth. The purpose of the cement is to bond the pin to the porcelain. Cement expansion creates radial cracks in the cement and porcelain shell resulting in two possible failure modes:

- Mechanical Failure: where the pin separates from the porcelain causing a conductor drop; and/or,
- Electrical Failure: where the cracked porcelain reduces insulating properties.

The cement growth phenomenon is illustrated in Figure 33. Cracks in the cement and porcelain shell are not readily visible or easily detectable. Insulators suffering from cement expansion are expected to fail prematurely and unpredictably since failure is influenced by mechanical load and environmental conditions.

Figure 33 - Porcelain Insulator Unit Affected by Cement Expansion

To address concerns associated with defective porcelain insulators, Hydro One retained a third-party expert, EPRI to perform laboratory testing on COB and CP porcelain insulators in order to assess their condition. The purpose of the study was to assist Hydro One in determining the pacing of porcelain insulator replacement.

Phase one of the EPRI study was completed in 2016 and included testing of 299 insulators removed from a combination of dead-end and suspension strings installed in publicly accessible (critical) locations. Phase one testing was intended to provide an expedient assessment of the condition of the in-service insulators in question. The results of the Phase one study supported the urgent replacement of COB and CP insulators manufactured between 1965 and 1982 that are installed in publicly accessible (critical) structures where public safety is at risk.

A large proportion of the insulators tested (37%) during the Phase one study failed electrically or mechanically at loads below their rated mechanical and electrical strength. There was a significant number of punctured insulators (electrical failing load of zero), and the test data showed a large variation in failing loads which would not be expected for a healthy insulator population. The condition of these Hydro One insulators was assessed through benchmarking by EPRI and public domain test data. This benchmarking data was obtained through testing of similar vintage insulators which had been in service for a comparable duration under similar field conditions. The performance of Hydro One's and the benchmarking insulators was also compared to current and historic requirements for new insulators. The test results presented an initial snapshot of the condition of the population of defective insulators in-service on Hydro One's transmission system. Although the sample of insulators tested was not sufficient to perform a rigorous statistical analysis upon which to base recommendations, the results strongly suggested that the installed insulator population comprising CP and COB insulators manufactured between 1965 and 1982 had reached or was at least approaching the end of useful life.

Phase two of the testing was performed in 2017. Those tests were carried out on 591 insulators. The intent of the Phase two tests was to supplement the Phase one data and to provide data on the rate of deterioration of the insulator population. The results of the analysis showed that:

- a large number of the tested insulators exhibited porcelain cracking after mechanical and electrical testing;
- the propensity for the insulators to puncture (crack) during thermal mechanical cycling ("TMC");
- the insulators are highly susceptible to electrical puncture under steep transient voltages (e.g. lightning);
- TMC drastically decreases the already weak ability of the insulators to withstand electrical puncture; and
- a significant number of insulators separated mechanically during TMC.

These results suggest that the number of in-service punctured units will increase as the insulators experience significant mechanical loading events. When a string containing electrically punctured insulators undergoes a flashover due to lightning, contamination, or snow and ice bridging, there is a high likelihood that the ensuing power arc will pass through the punctured unit internally travelling from cap to pin. This results in significant heating and pressure buildup which can cause the cap and pin to separate and the conductor to drop. The greater the number of punctured insulators in the string, the higher the probability of string flashover and string separation. Insulators which are not punctured but have suffered deterioration in mechanical strength do not exhibit this behavior. If a string contains mechanically compromised units, the insulators will fail if the maximum applied load exceeds the units' remaining mechanical strength. The majority of conductor drops recently experienced on Hydro One's porcelain insulated transmission system fall into the former category.

The Phase one and two analyses provided overwhelming evidence supporting replacement of defective porcelain insulators to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation provided by EPRI is that the identified population of COB and CP insulators be removed from service as soon as practically possible.

The porcelain insulators manufactured by CP and COB are used province-wide in Hydro One's transmission system. There are approximately 34,000 circuit structures with defective porcelain insulators and roughly 15,000 have been identified as being on structures in publicly accessible (critical) locations. Publicly accessible (critical) structures include those located near roads, waterways, urban areas, golf courses, educational and health care facilities. To date approximately 8900 publicly accessible COB and/or CP insulators have been replaced. A breakdown of the defective population in relation to the total insulator population as of 2018 can be seen in Figure 34 below.

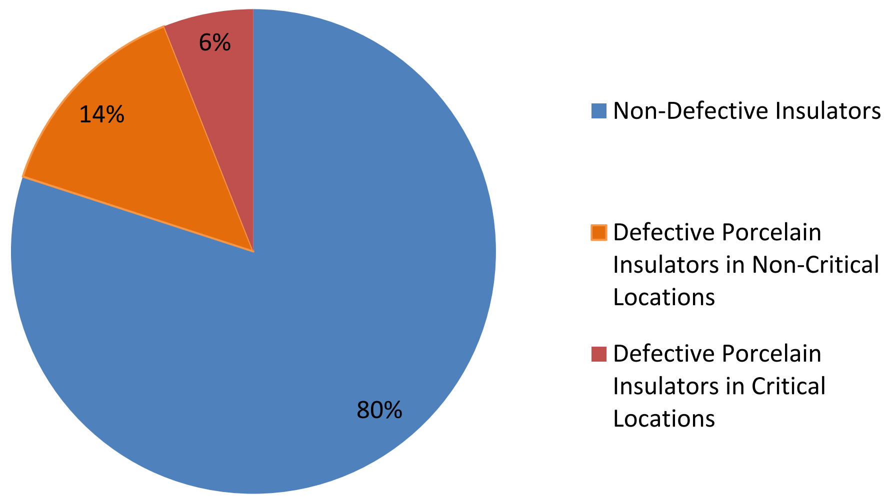

Figure 34 - Defective Porcelain Insulator Population

Hydro One has experienced porcelain insulators failures due to cement expansion. For example, in March 2015, an insulator on circuit V76R mechanically failed causing the conductor to fall to the ground in a commercial parking lot in Etobicoke. Similarly, in January 2017, an insulator on circuit HL3 mechanically failed causing the conductor to fall over a roadway in Hamilton. Photos of these failures are provided in Figure 35 through Figure 38 below.

Figure 35 - V76R Insulator Failure

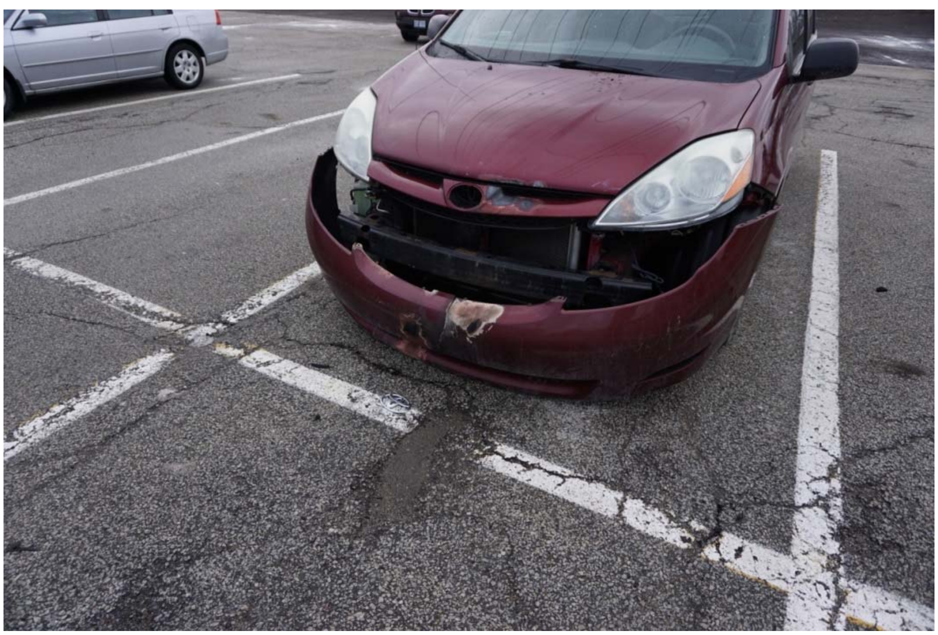

Figure 36 - V76R Insulator Failure

Figure 37 - V76R Insulator Failure

Figure 38 - HL3 Insulator Failure

Since portions of Hydro One's polymer insulator population are approaching their ESL, Hydro One retained EPRI to perform a detailed condition assessment of polymer insulators to assist Hydro One in determining the need and pacing of polymer insulator replacement. The condition assessment study focused on 87 polymer insulators from various manufacturers with the service life ranging from 13 to 26 years. The following three insulator configurations form the scope of the EPRI study:

- 230 kV suspension with large corona rings;
- 230 kV suspension with either small (known as a "donut") or no corona rings; and
- 115 kV dead end.

Based on its assessment of 87 insulators, EPRI found that the condition of polymer insulators currently in-service in Hydro One's transmission system varies based on voltage, manufacturer and use of corona rings. The results of this study have shown that Hydro One should plan to remove specific 230 kV insulators from service as soon as possible due to immediate or high risk of failure. Other types of 230 kV insulators should continue to be assessed periodically for signs and degree of degradation. EPRI further recommends that linemen should check the integrity of these insulators prior to performing any live maintenance procedures due to potential safety issues. Considering the study results, Hydro One will prioritize the removal of specific polymer insulators in its current replacement program.

The need to address the polymer insulator issue is underscored by two failures which occurred in October and November 2016. Both failures were a result of a 230 kV polymer suspension insulators on C28C failing mechanically resulting in a conductor drop, as shown in the photos in Figure 39 through Figure 41. The dropped conductor did not contact the ground but was held in the structure window.

Figure 39 – Failed Polymer Insulator

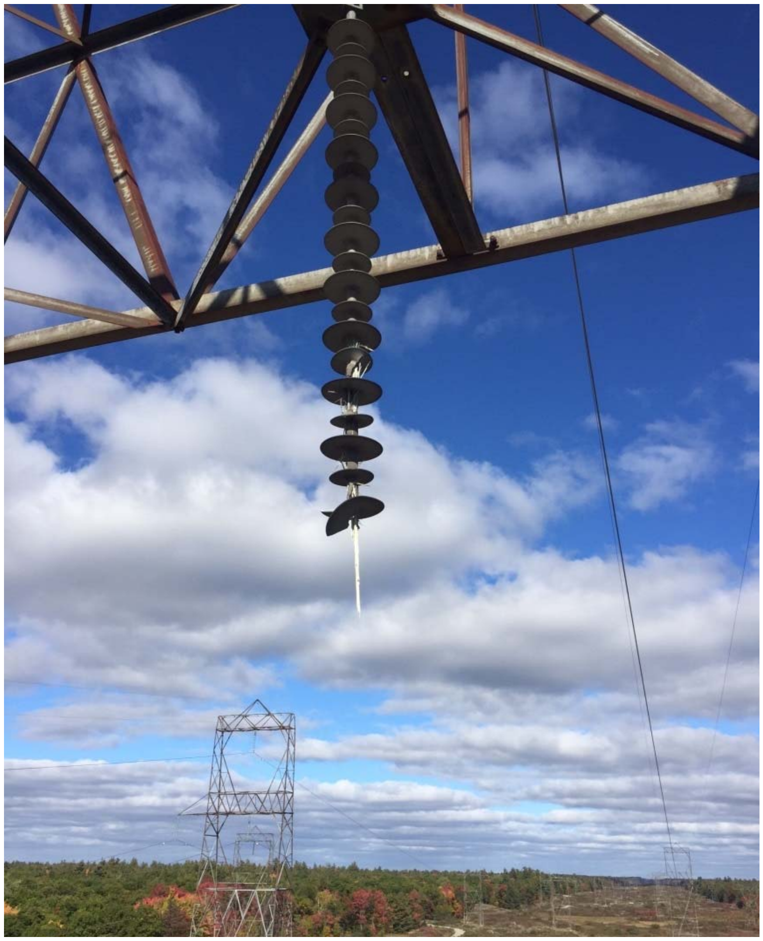

Figure 40 – Failed Polymer Insulator

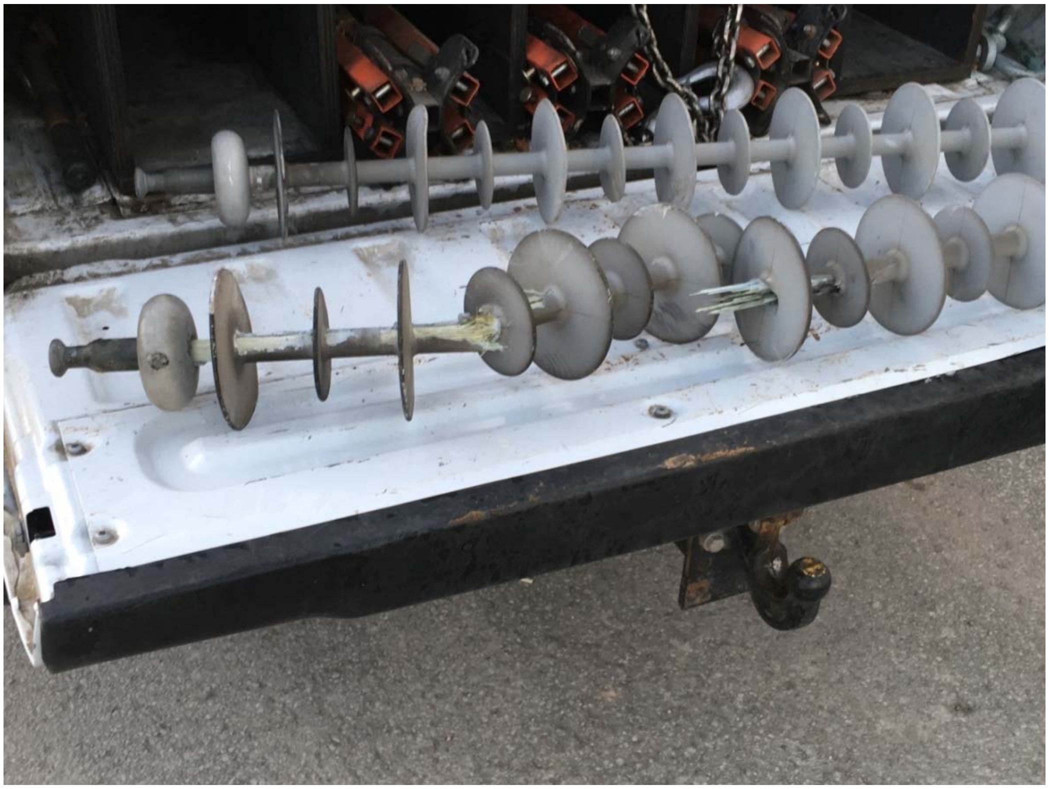

Figure 41 – Failed Polymer Insulator

Performance

Figure 42 and Figure 43 illustrate the frequency and duration of insulator-caused circuit outages between 2008 and 2017, which have remained relatively stable. However, the number of failures is expected to rise due to the degradation of the known defective COB and CP porcelain insulators. Figure 44 illustrates the number of COB and CP failures over the past 10 years, which shows a significant upward trend.

Failed insulators normally result in a sustained forced outage because of the permanent electrical fault they create. Repair time can be significant, averaging 37 hours per outage, depending on the location and severity of the failure. The majority of the recent failures have been due to defective porcelain or polymer insulators.

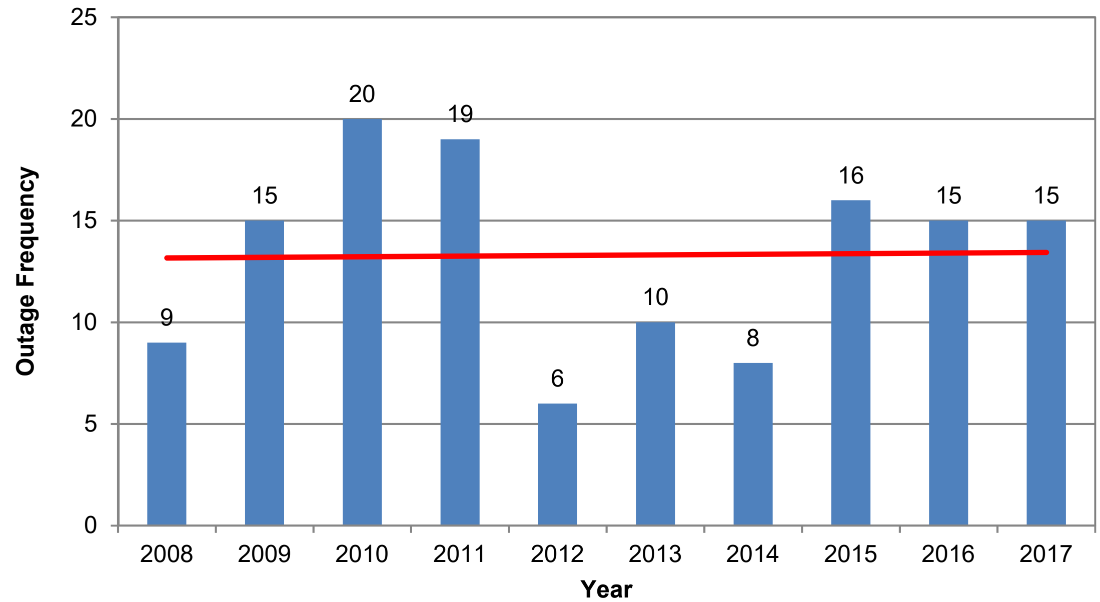

Figure 42 - Insulator Outage Frequency

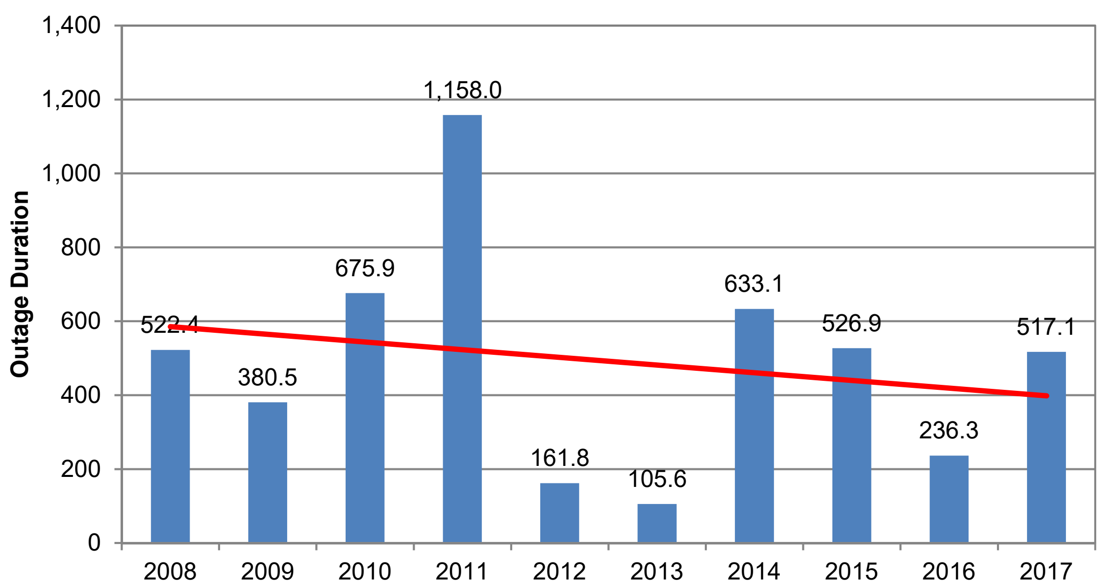

Figure 43 - Insulator Outage Duration

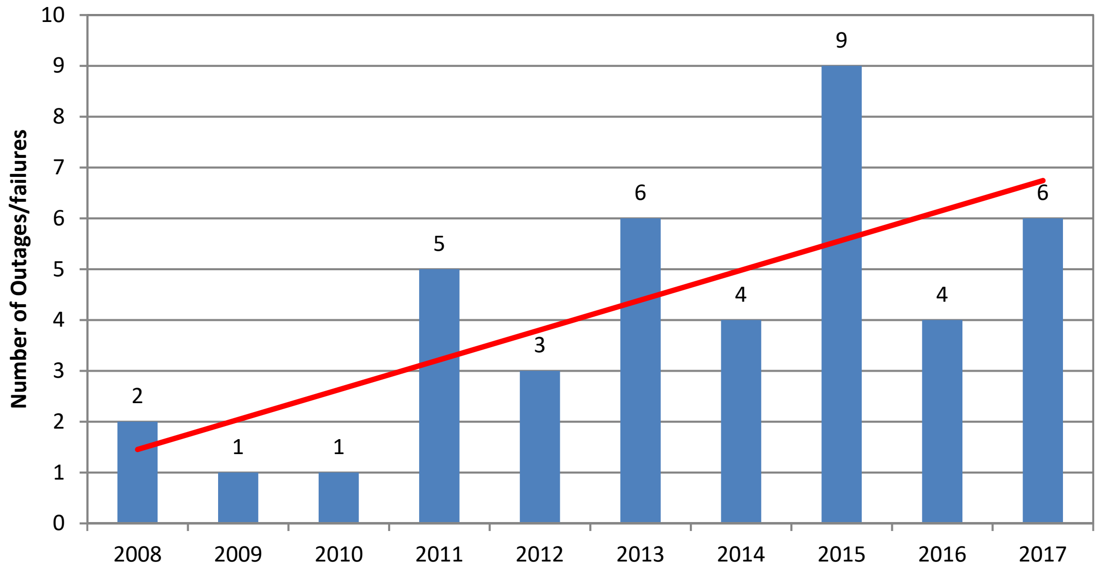

Figure 44- Frequency of COB/CP Insulator Failures

Safety

Many insulators are used on structures in public areas or in areas that can be easily accessed by the public. In the event of a mechanical failure and conductor drop, these locations pose a high risk to the public, and therefore need to be prioritized as part of a proactive plan.

Future Outlook / Need

Porcelain Insulator Replacement

The testing results discussed in Section 2.2.2.4 provide overwhelming evidence supporting replacement of defective porcelain insulators to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation provided by EPRI is to remove the identified population of COB and CP insulators from service as soon as practically possible. As a result, Hydro One has targeted for replacement defective porcelain insulators that pose a substantial public safety risk, as further discussed in Section 2.3.2.4 of this TSP and ISD SR-25.

Polymer Insulator Replacement

Polymer insulators in 230 kV dead-end configurations are known to fail due to their exposure to high electric-field gradients that cause silicone degradation. The degradation exposes the fibreglass rod to moisture which causes rapid deterioration leading to failure. These insulators are also being targeted for replacement.

Hydro One is using the information provided by EPRI, discussed in Section 2.2.2.4, to optimize the overall replacement program with respect to the risk of in-service failure.

2.2.2.5 RIGHTS OF WAY

Asset Description / Purpose

The strip of land that is occupied by a transmission line is referred to as a right-of-way ("ROW") or a corridor. Hydro One's in-service ROWs cover an area of approximately 82,500 hectares and consist of 115, 230, 345 and 500 kV circuits. To ensure system reliability and access, Hydro One is responsible for maintaining clearance distances between the energized equipment and the vegetation located on and adjacent to all of these ROWs.

Asset Condition / Demographics

Demographics

Hydro One's service territory is divided into three operational Forestry Zones: North, South and East. These zones have been defined based on similarities in weather patterns and vegetation growth conditions and are used to maximize operational efficiencies.

Hydro One maintains its ROWs on vegetation clearing cycles of 4, 6 or 8 years. Fast growth areas are placed on a shorter cycle. Cycle lengths have been set to ensure that

ROWs are in good condition and maintain a sustainable level of reliability between maintenance cycles. A summary of Hydro One's ROW route hectares by zone and maintenance cycle is shown in Figure 45.

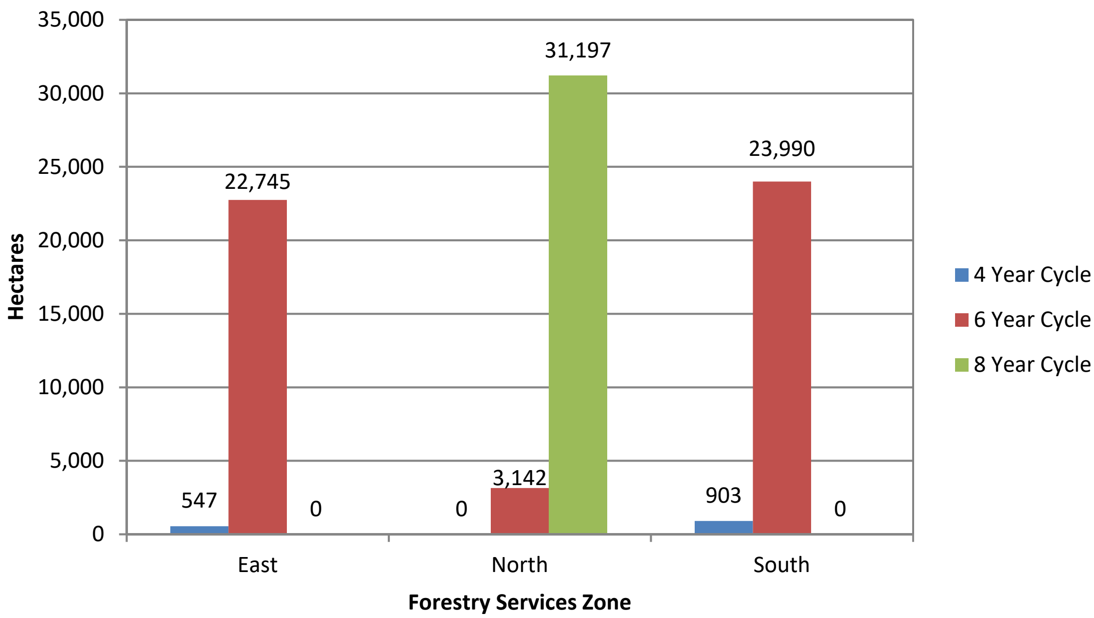

Figure 45 - Hectares by Maintenance Cycle Length and Zone

Condition

If left unmanaged, vegetation on or adjacent to a ROW presents the risk of growing or falling into energized conductors and preventing access to Hydro One's transmission lines. Figure 46 illustrates the breakdown of ROWs in poor, fair, and good condition. Approximately 9% (i.e. 7,400 hectares) of Hydro One's ROWs are beyond their target clearing cycle and are therefore considered to be in poor condition.

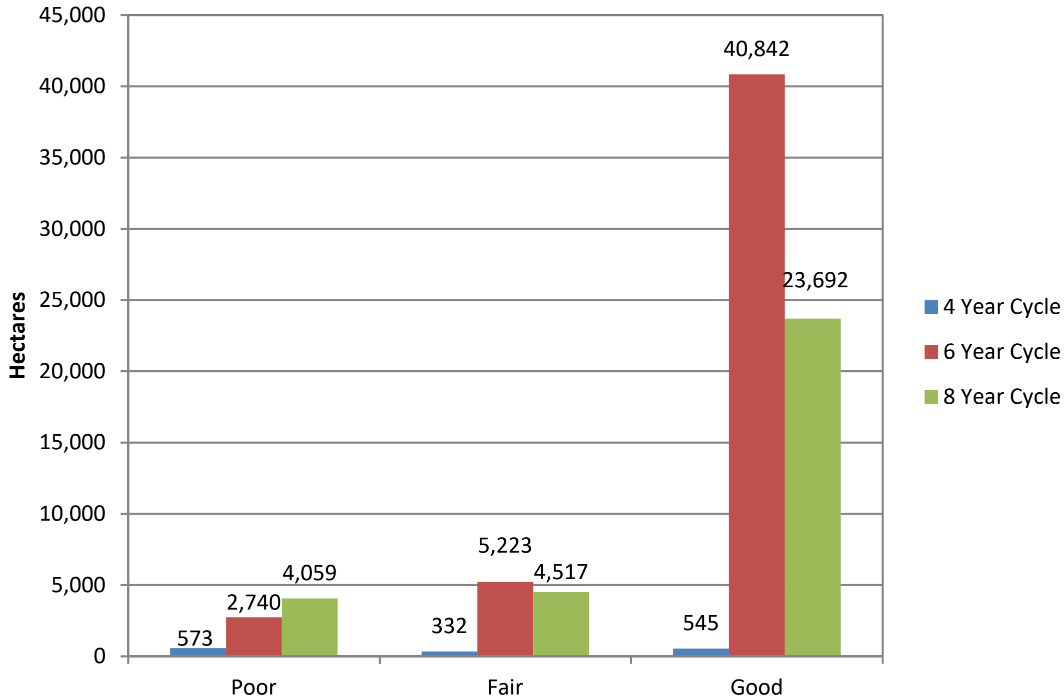

Figure 46 – Condition of Hydro One ROW

Performance

Asset performance for vegetation management is measured by the number of annual vegetation caused outages. The majority of Hydro One's vegetation related outages have been due to trees falling on 115 kV conductors from outside of the ROW due to extreme weather conditions such as heavy winds, snow and/or ice storms.

Hydro One's transmission lines are subject to NERC standard FAC-003, *Transmission Vegetation Management Reliability Standard*, which currently requires Hydro One to report all vegetation related outages on 230, 345 and 500 kV circuits within Hydro One's control (i.e. natural disasters and human activity such as logging are excluded). Vegetation caused outages affecting Hydro One's 115 kV system are not currently NERC reportable. Figure 47 provides a summary of all vegetation caused forced outages on

Hydro One's network presenting both the NERC reportable and non-reportable outages.[11] The duration of these outages is displayed in Figure 48.

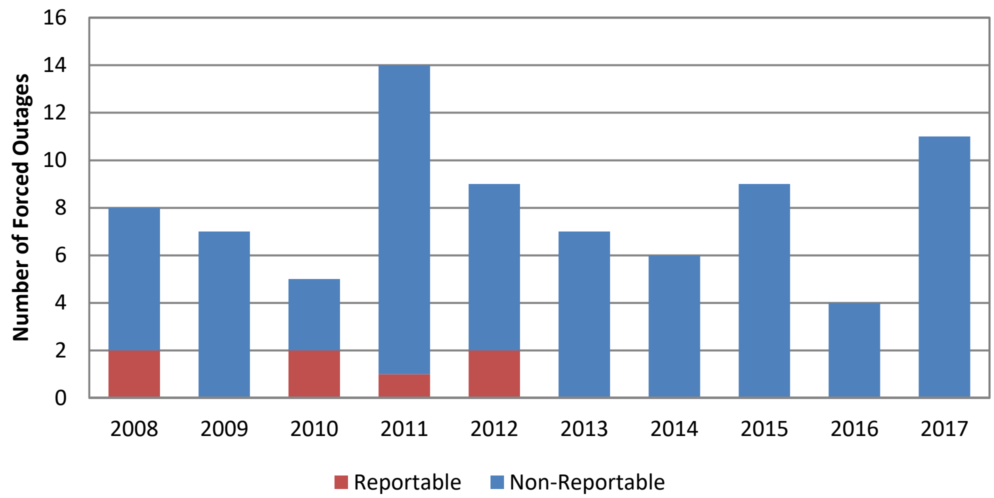

Figure 47 - Hydro One's Vegetation Related Outage Frequency

[11] NERC reportable outages have primarily decreased due to changes in NERC's definition of which outages are reportable. For example, there have been less NERC reportable outages in recent years because momentary and human caused outages are now excluded.

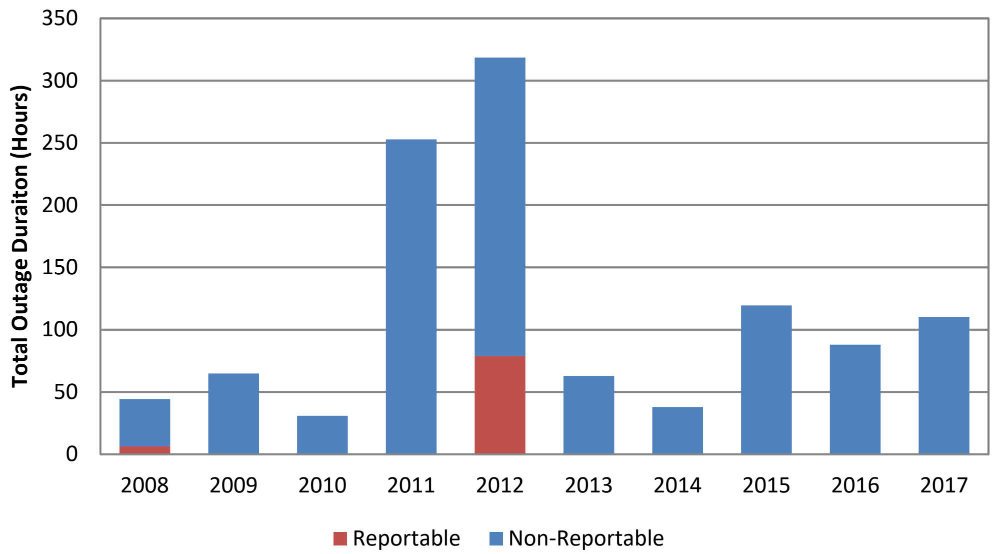

Figure 48 - Duration of Vegetation Related Outages on Hydro One Circuits

Future Outlook / Need

As maintenance cycles extend past targeted cycles, vegetation growth continues to increase along Hydro One's transmission corridors. Consequently, approximately 7,400 ha of ROW are considered to be in poor condition. Hydro One plans to prioritize vegetation maintenance on NERC FAC-003 regulated and critical ROWs in order to manage this backlog. To further optimize the program, new technological opportunities, such as Light Detection and Ranging ("LiDAR"), are being considered to help identify any potential vegetation encroachments upon Hydro One's transmission lines. As discussed in Section 2.3.2.5.3, LiDAR is a remote sensing technology that is used by utilities to obtain accurate geospatial images and measurements of circuits and the vegetation surrounding them.

2.2.2.6 SHIELDWIRE

Asset Description / Purpose

Shieldwire is used to provide lightning protection and grounding continuity to transmission lines. There are approximately 34,600 km of shieldwire strung along Hydro One's overhead transmission lines. Hydro One's network consists of the following five types of shieldwire: (i) Galvanized Steel, (ii) Alumoweld, (iii) Optical Ground Wire ("OPGW"), (iv) Aluminum Conductor Steel Reinforced ("ACSR") and (v) Copperweld. Alumoweld and OPGW are the most recent types of shieldwire and are currently used to replace EOL shieldwire. Further details regarding each type of shieldwire are provided in Table 23.

Table 23 – Summary of Shieldwire by Type

Shieldwire Type	Vintage	Description
Galvanized Steel	Installed until approx. 1990	Galvanized Steel is the most common type of shieldwire currently installed on the Hydro One network. However, galvanized steel shieldwire is no longer being used for new installations by Hydro One as the protective zinc coating tends to deteriorate over time and result in a loss of metal, a reduction in mechanical strength, and eventual failure of the shieldwire.
Aluminum cladded steel, also known as Alumoweld	Installed for approximately 40 years	Alumoweld is the most recent type of shieldwire installed on Hydro One's network and is being used to replace shieldwire that has reached EOL. Alumoweld shieldwire consists of a thick aluminum cladding used to protect against corrosion and a steel, conductive core.
Optical Ground Wire ("OPGW")	Installed for approximately 30 years	In locations where a fibre optic communication channel is required for telecommunication purposes, Hydro One installs OPGW, which consists of Alumoweld shieldwire with a core containing fibre optic strands.

Shieldwire Type	Vintage	Description
Aluminum Conductor Steel Reinforced ("ACSR")	Installed as required	ACSR conductors are installed as shieldwire on a limited basis and are used when estimated fault current levels are too high for conventional galvanized steel or Alumoweld wires.
Copper cladded steel, also known as Copperweld	Installed between 1930 and 1960	Copperweld is an older type of shieldwire that was installed in limited numbers across the Hydro One network. This shieldwire is not capable of adequately sustaining lightning strikes and is therefore targeted for replacement.

Asset Condition / Demographics

Demographics

The average age of Hydro One's shieldwire fleet is approximately 37 years. Approximately 61% of Hydro One's shieldwire fleet is galvanized steel and 30% is Alumoweld. The demographic details of Hydro One's shieldwire fleet as of year-end 2018 are displayed in Table 24. Due to historic construction and demographic patterns, Hydro One is now entering a period where many shieldwire sections are approaching ESL.

Table 24 - Summary of Shieldwire Demographics

Shieldwire Type	In- Service Length (km)	Average Age	ESL (Years)	Currently Beyond ESL (km)	Beyond ESL 2024 (km)	Beyond ESL 2029 (km)
Galvanized Steel	21,142	53	50	10,005	15,300	16,769
Alumoweld	10,682	27	60	0	0	0
OPGW	2,017	21	40	0	0	0
ACSR	599	45	90	0	4	14
Copperweld	204	63	N/A*	204	204	204
Total	**34,644**	**37**	**-**	**10,209**	**15,508**	**16,987**

**ESL is not applicable to Copperweld as it is end of life regardless of age*

Condition

Hydro One does not replace shieldwire based upon age. A detailed condition assessment is used to determine when shieldwire has reached EOL.

Shieldwire that has been verified by condition assessment to have reached EOL is considered to be high risk and is scheduled for replacement. Fair risk shieldwire assets have condition test results that indicate minor deterioration but have not yet reached EOL. These shieldwires are scheduled for re-assessment at a later date. The timeframe for re-assessment varies depending on the level of deterioration indicated by the test results. Shieldwire classified as low risk has either been assessed to be in good condition or has not yet reached the age at which shieldwire condition assessment begins. Of the total shieldwire fleet, 24% has reached the condition assessment age threshold, which varies depending on shieldwire materials, as further discussed in Section 2.3.2.6, and will be assessed in the future under Hydro One's shieldwire condition assessment program. The condition of Hydro One's shieldwire fleet is summarized in Figure 49.

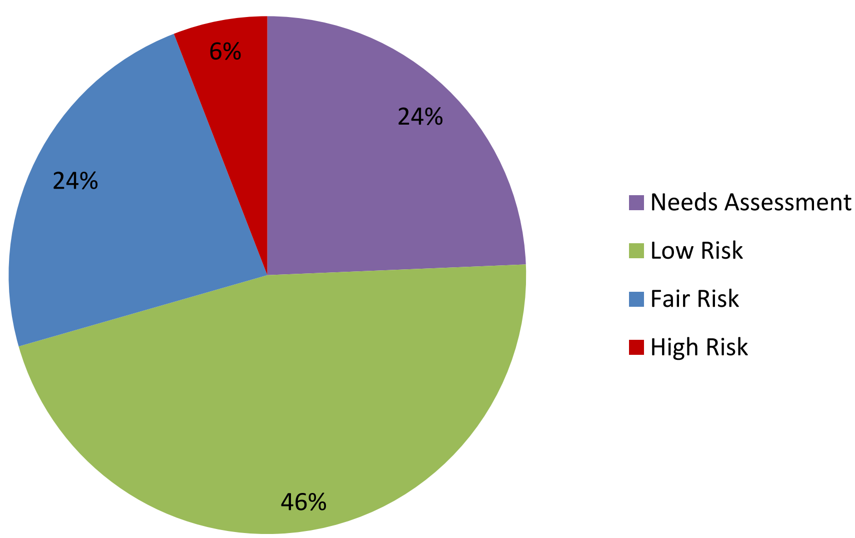

Figure 49 - Condition Risk of Shieldwire Assets

Performance

Asset performance for shieldwire is measured by the number of shieldwire caused outages that occur each year. The majority of Hydro One's shieldwire caused outages occur during extreme weather conditions such as heavy winds, snow, and/or ice storms. Figure 50 and Figure 51 provide a summary of all shieldwire caused forced outages.

The frequency of shieldwire caused forced outages has remained fairly stable over the recent years, while outage duration increased significantly in 2016 due to inclement weather that prevented shieldwire repairs. Circuit outages are common when shieldwire failure occurs, as the broken shieldwire typically makes contact with the conductors before falling to the ground. In addition, broken and hanging shieldwire can expose members of the public or Hydro One employees to a safety risk.

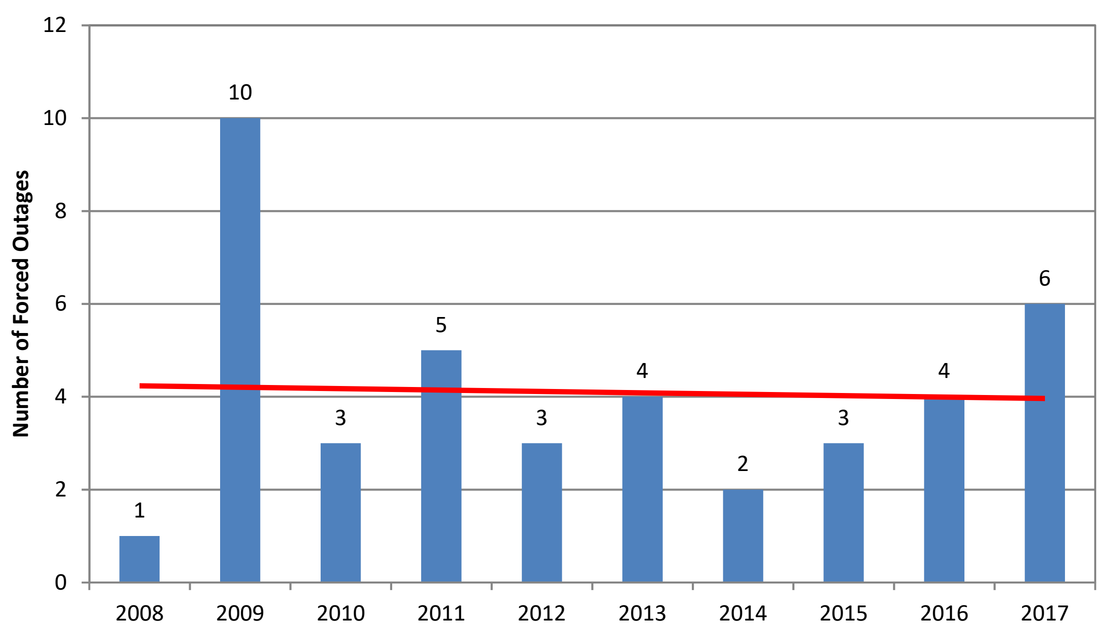

Figure 50 - Frequency of Shieldwire Related Outages

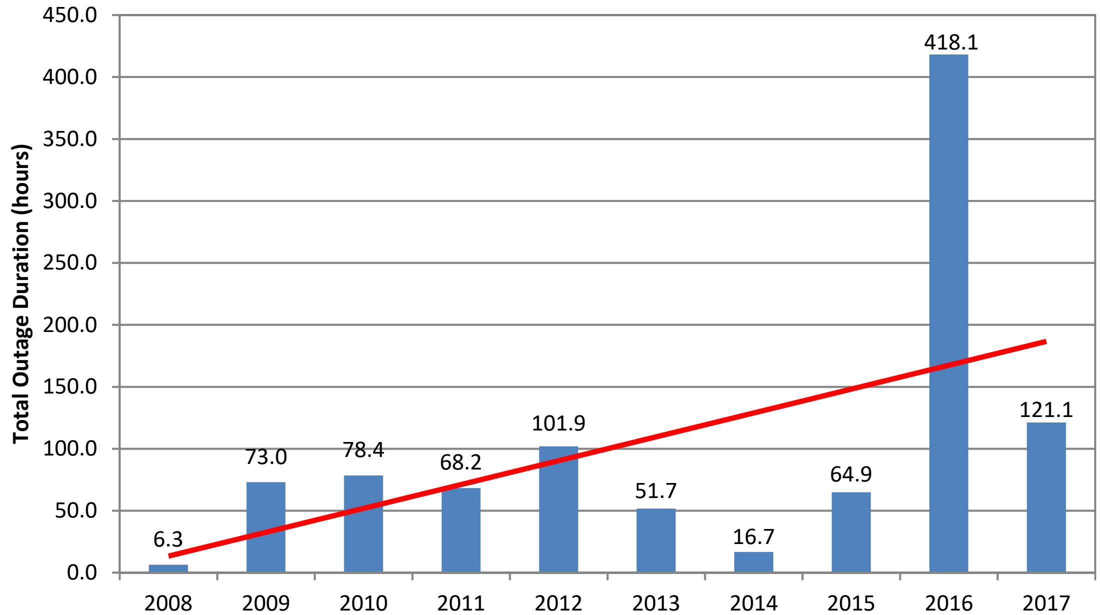

Figure 51 - Duration of Shieldwire Related Outages

Future Outlook / Need

To prevent shieldwire-related outages and reduce the risk to public safety, Hydro One is focusing on replacing all shieldwire that has been confirmed through condition assessment to have reached their EOL. Going forward all shieldwire that requires replacement will be replaced with Alumoweld or OPGW shieldwire, with the exception of any line sections requiring ACSR to withstand higher fault currents.

Currently, 24% of Hydro One's shieldwire fleet has reached the age threshold for condition assessment. These assessments are required to plan, schedule and execute replacements of EOL shieldwire.

2.2.2.7 OTHER LINES ASSETS

Asset Description / Purpose

Other transmission line assets include U-bolts, switches, aviation lights, and numerous other hardware components such as dampers and ground wires.

U-bolt Hardware

U-bolt hardware is the physical link between a transmission structure and insulator (refer to Figure 52). The majority of suspension circuit structures contain U-bolt hardware.

Figure 52 - U-bolt on a suspension structure

Lines Switches

Transmission line switches are primarily used to sectionalize lines and isolate customers during planned and unplanned outages. Transmission line switches can be generalized into the two types: In-Line Disconnect switches and Mid-Span-Openers ("MSO").

Aviation Obstruction Lights

Hydro One has approximately 100 transmission line structures that are equipped with aviation obstruction lighting to warn pilots of potential objects within the flight path. These systems must comply with Transport Canada's aviation regulation "Standard 621 –

Obstruction Marking and Lighting." Structures equipped with aviation obstruction lights are located near airports or river crossings.

Figure 53 - Aviation Obstruction Lighting

Asset Condition / Demographics

U-bolt Hardware

U-bolt hardware under suspension configuration deteriorates over time due to the swinging movement of the attached insulators and conductors. The swinging causes friction and wear on the U-bolt hardware or tower eye. Over time the cross-sectional area of the U-bolt and/or the tower eye wears out as shown in Figure 54. Eventually the hardware will no longer have the mechanical strength to support the suspended insulator and conductor, leading to a catastrophic failure.

Figure 54 - A Worn U-bolt

There are various external factors, such as wind, weather and circuit configuration, that can impact the rate of deterioration of U-bolt hardware. The age of U-bolt hardware alone does not reflect its physical condition. U-bolt hardware are visually assessed by either detailed helicopter inspection or climbing inspection to determine its physical condition.

U-bolt replacement is primarily driven by EOL condition, when the wear on the U-bolt cross sectional area has reached over 50%. The ESL of U-bolt hardware is set at 65 years.

Line Switches

Time-based preventive maintenance is performed on Hydro One line switches. During maintenance, switch functionality is verified and associated defects are reported for corrective repair or future replacement is planned.

Aviation Obstruction Lights

All of the aviation obstruction lighting systems installed on Hydro One Transmission structures underwent replacements between 2003 and 2012. All of the installed systems were manufactured by the company OTL. Over the service life of the aviation lighting systems, significant investments were made to repair or replace defective components. These defects primarily include: repeated integrated circuit cards failure, xenon flash tube capacitors failure, malfunctioning control boxes, and incorrect remote monitoring alarms. In 2016, OTL went out of business, thereby affecting technical support and spare parts availability. As such, Hydro One approved a new vendor to supply material for new replacement systems. Installation of this new system started in 2016. As the lighting systems are replaced, useable parts are salvaged as spares for remaining in-service systems.

Future Outlook / Need

U-bolt hardware

To maintain system reliability and reduce the risk to public safety, Hydro One will continue to utilize detailed helicopter inspection and climbing inspection to assess U-bolt condition of circuits that has reached the age threshold for condition assessment.

EOL U-bolts cannot be repaired and are therefore targeted for replacement. A U-bolt is considered hardware associated with the structure/insulator. Therefore, component replacement programs such as wood pole replacement, insulator replacement or line refurbishment projects will typically include replacement of U-bolt hardware on the circuit structure. For example, during insulator replacement, the associated U-bolt hardware will be replaced at the same time for execution efficiency. EOL U-bolts that are not addressed through component replacement programs will be replaced through the planned corrective program.

Lines switches

Switches that are inoperable, obsolete or at EOL are targeted for replacement. The intent is to proactively replace switches prior to failure, minimizing customer and system impact in the event that the switch is required.

Aviation Obstruction Lights

LED aviation obstruction lighting systems are to be installed on both transmission structures and telecom microwave towers. The aviation light locations identified for replacement are prioritized based on the type of lighting system (determined by tower height) and identified defects. The existing plan is to replace all aviation light systems manufactured by OTL by the end of 2023.

Emergency Replacement

Each year, a number of transmission line components fail or are identified to be in imminent danger of failure, due to adverse weather, component deterioration, vandalism, or accidents. Replacement or repair of these line components is carried out under a demand emergency program to minimize reliability and safety risk. The type of emergency work covered includes replacement of failed or defective transmission line components such as wood structures, cross-arms, towers, insulators, conductor, shieldwire and hardware.

2.2.3 (5.3.2 B, C, D) ASSET COMPONENT INFORMATION – OTHER ASSETS

Other assets of the Hydro One transmission system include real estate and facilities, transport and work equipment and information technology. These assets support all lines of business and are vital to the operation and maintenance of the transmission system.

2.2.3.1 REAL ESTATE AND FACILITIES

Asset Description / Purpose

Hydro One Facilities and Real Estate assets include sites and buildings accommodating administrative and service functions to support business operations. Administrative and service functions include: Administrative Centres, Operations Centres, Maintenance/Work Centres, Warehouses, Maintenance Garages, Helicopter Hangars, Material Yards and limited others ("Facilities"). Capital investment is periodically required to provide appropriate and adequate accommodations for core work programs, changing requirements of the various lines of business and/or the operation and security of network equipment.

In addition, Facilities and Real Estate maintains buildings and related site infrastructure that exclusively houses transmission network equipment ("Network Buildings"). The objective is to provide for the ongoing operation and security of the network equipment.

Asset Condition / Demographics

Hydro One Facilities and Real Estate manages 323 transmission sites which contain approximately 994 buildings, comprising both Facilities and Network Buildings. All of these transmission Facilities are owned by Hydro One. In addition, there are 132

Facilities independent of transmission sites containing 397 buildings, where 288 buildings are Hydro One owned on 89 sites and 109 buildings are leased on 43 sites.
The assessment of Facilities and Network Buildings is an ongoing process. The focus to date has been on field assessments of roof and HVAC systems, which are considered critical to operations. These field assessments are used to establish condition profiles to prioritize and plan work.

Facilities are comprised of multiple buildings and are distributed to align with the configuration and demands of the network and customers as well as the diverse operational requirements of the various lines of business. Largely historically based, network additions, end of life conditions, performance and market conditions dictate periodic readjustment.

The average age of the Facilities and Network Buildings across the province is approximately 50 years old supporting the need to closely manage and maintain them through planned condition assessment.

Approximately one third of the Facilities supporting the transmission work program are located within transmission sites. These facilities are often configured in a co-occupancy arrangement with network equipment as originally planned or through repurposing of space (e.g. conversion of control rooms).

Given that most Network Buildings are over 50 years old, their configuration, design and layout are dated and they do not necessarily meet present day standards. Building condition assessments of all Facilities are ongoing. To date, assessments have been completed for approximately 70% of the Facilities. Condition assessments account for a range of factors, including environmental issues such as mould or water treatment upgrades, adequacy for work program and space demands, and security and safety concerns for employees and first responders. These assessments have identified that approximately 25% of the buildings are in very poor and poor condition. Without capital investment, it is estimated that more than half of the Facilities will be assessed as being in very poor and poor condition by 2024.

Future Outlook / Need

Facilities requirements are based on operational needs at each site while ensuring health and safety standards are maintained. Older and re-purposed buildings/sites are assessed on a case by case basis and are commonly found to be undersized, ill configured and underperforming to meet current operational requirements in addition to not meeting current building occupancy standards and regulations. These conditions contribute to inefficiencies to business operations and elevated health and safety risks in conjunction with increasing maintenance and repair costs associated with aging assets.

The need to refresh these aging assets considers various alternatives, that include replacement or renovation, but with the overarching objective of consolidating Facilities to reduce cost.

To address the estimated deterioration of Hydro One's Facilities and Network Buildings, approximately $15 million per year in capital investment is required to keep the majority of these structures in good and fair condition while carefully maintaining the ones in poor condition.

2.2.3.2 TRANSPORT & WORK EQUIPMENT

Hydro One Fleet Management Services provides centralized and turnkey services that include equipment acquisition, maintenance, administration, vehicle replacement and final disposition of Hydro One's Transport and Work Equipment ("TWE").

Fleet vehicles support various lines of business ("LOB"), including Distribution Lines, Stations, Forestry, and Construction Services. Fleet vehicles must be adequately maintained to ensure public safety, employee safety, compliance with laws and regulations (including CSA 225, the *Highway Traffic Act* and the Commercial Vehicle Operator's Registration regulations).

Asset Description / Purpose

Hydro One Fleet Management Services controls and manages vehicles and other fleet equipment to support distribution and transmission work programs and staffing requirements. Fleet assets are categorized into 56 classes and 5 large equipment categories as shown in Table 25 below:

Table 25 - Summary of Fleet Vehicles

Large Categories	Equipment Type	LOB Requirement
Light duty	**Cars/SUVs**	Used by all LOBs for employees who drive more than 23,000 km.
	Vans/Pickups	Used by all LOBs to transport tools and crews to work locations and to tow small trailers
Heavy duty Radial Boom Derrick 	**Service Trucks**	Used primarily by Distribution Lines, Forestry, Stations, Construction and Fleet Maintenance to support and service off-road units and work locations
	Highway Tractors	Used primarily by Distribution Lines, Forestry and Construction to tow large equipment and Off-Road units.
	Cranes	Used primarily by Distribution Lines, and Construction for lifting poles and other material.
	Bucket Trucks	Used primarily by Distribution Lines and Forestry to work at heights to complete line maintenance and tree trimming.
	Radial Boom Derricks ("RBD")	Used by Distribution Lines to dig holes and to set poles at road side and for heavy towing.

Off-Road 	**Off Roads**	Used by Distribution Lines, Forestry and Construction to perform the following activities: build roads and right-of-ways, clearing brush, build/maintain lines and act as personnel/material carriers.
Miscellaneous Chipper  Tensioner 	**Boats**	Used primarily by Distribution Lines and Forestry work programs and strategically located around the province to minimize hauling the boats from waterway to waterway to access our isolated customers.
	Trailers	Used by all LOBs and includes boat trailers, office trailers, open-deck trailers, cargo trailers, pole trailers for various business requirements.
	Chippers	Used by Forestry in conjunction with the bucket trucks required for environmental cleanup.
	Manlifts	Used by Stations working within a non-energized environment and by Fleet for working on elevated equipment/aerial devices.
	Forklifts	Used by all LOBs and are required for loading/unloading material at various work sites.
	Tensioners	Used by Distribution Lines and Construction for stringing projects.
Helicopters 	**Helicopter**	Used by Distribution Lines, Forestry and Construction to inspect transmission lines, conduct line maintenance and to transport workers and materials to remote locations.

Asset Condition / Demographics

Hydro One has approximately 7,000 vehicles and other fleet equipment. Table 26 shows the breakdown of the Fleet asset demographics and their current condition. Fleet Management Services and the LOB complete annual asset reviews. Assets are identified for replacement based on their ESL and mileage which are recommended by the manufacturers as a guideline to initially identify vehicles for replacement. Specialized technicians will assess the condition of the asset to determine if the asset can be retained for an additional period of time or if it needs to be replaced.

Table 26 - Average Age and ESL of TWE[1]

Equipment Type	Quantity of TWE Fleet (%)	Average Age (Years)	Average Mileage (kms)	ESL (Years)	ESL (kms)
Light	37.8%	4	108,000	6	180,000
Heavy	19.5%	7	127,000	8-14	300,000-400,000
Off-Road	6.6%	8	N/A	individual asset assessment	
Miscellaneous	36.1%	8	N/A	individual asset assessment	
Helicopters	0.1%	15	N/A	individual asset assessment	

[1] Data from December 31, 2018

<u>Condition</u>

Hydro One specialized technicians monitor and asses the condition of the transport and work equipment during inspections and routine maintenance. Adequate maintenance and service intervals help to reduce degradation of the equipment and maximize the life of the asset. The condition of the assets, along with the age and kilometres driven/hours used, determine the need for replacement and any risks that need to be mitigated.

Future Outlook / Need

Fleet requirements for asset replacement are primarily based on industry standards or manufacturers' recommendations for life cycle expectancy. This includes age and kilometres driven as well as the overall condition of the asset. The objective is optimal operating cost management, maximum LOB productivity and reduced environmental impacts by minimizing downtime and travel time and by leveraging technology with continuous improvement opportunities.

Fleet Electrification

In an effort to reduce Hydro One's carbon footprint, Fleet Management Services is analyzing the benefits of electric vehicles that would be suitable for the Company's needs in relation to the Hydro One service area geography, weather conditions and work execution requirements. In this regard, Hydro One has tested and purchased a new Chevrolet Bolt EV and Chevrolet Volt EV in 2018 for long term evaluation and will be introducing a new Altec JEMS 55-ft bucket truck and a Altec JEMS 48-ft bucket truck into the Fleet equipped with a fully Electric Power Take Off (PTO).

Fleet Management Services is continuing to work with the Corporate Strategy Team on new Fleet Electrification opportunities as the industry evolves (Hybrid/PHEV/EV). A cost benefit analysis is being completed to determine feasibility of implementation of this technology into Hydro One's Fleet.

2.2.3.3 INFORMATION TECHNOLOGY

Asset Description / Purpose

Information Technology ("IT") refers to computer systems (hardware, software and applications), enterprise data storage and processing systems, and voice communication systems that support grid and administrative operations. The reliability of these systems is critical as they must always be available to customers and to the employees delivering Hydro One's business services.

Hydro One currently manages approximately $150 million in IT assets and uses approximately 800 business software applications. IT assets include:

- Enterprise Resource Planning ("ERP") systems that provide the tools to seamlessly manage administration across multiple lines of business.
- Work Management Systems that enable timely connection of customers and effective operations through scheduled plant maintenance or storm restoration activities.
- Minor Fixed Assets ("MFA") that include desktops, laptops, printers, plotters, rugged tablets and mobile devices which are used to provide the information and capability of Hydro One's enterprise systems to employees.
- Telecommunication infrastructure that includes hardware equipment and software for Hydro One's network and telecommunication needs.

Asset Condition / Demographics

Demographics

The replacement of aging hardware is based on technical obsolescence and the nature of the applications running on the hardware. IT MFA is broken down into the categories shown in Table 27 below with corresponding quantities and projections.

Table 27 - IT Minor Fixed Assets

Description	Quantity	Average Age (Years)	End of Support (Years)	Number of Units Currently beyond End of Support
Enterprise Servers	489	4.0	5	431
Desktop Computers	1727	3.4	4	1407
Laptop Computers	5829	2.8	4	1161
Tablets	1408	2.5	5	326
Printers and Plotters	1165	5.5	5	652
Volume of Enterprise Data Storage (TB)	2418	2.6	5	0

Investment in MFA Enterprise Servers and Storage is required to respond to and manage annual growth in demand for additional IT processing and storage capacity and to address servers approaching End of Support.

As detailed in Table 27, approximately 37.5%[12] of Hydro One's IT MFA is currently at End of Support. The condition and required replacement of these assets is described below.

Condition

Hydro One manages the condition of its IT hardware by managing assets through a lifecycle management program. The primary factor that drives the program is the vendor warranty period. All assets are managed under a standard warranty and vendor support period of three to five years to ensure hardware currency and supportability. Once the asset age exceeds the vendor support period of three to five years, the asset is deemed to have reached End of Support. It is at this point in time that the asset is either placed under extended maintenance with the vendor or flagged for replacement.

The replacement timeline and approach is consistent with industry standards, as outlined by leading technology analytics organizations, including Gartner[13]. Warranty periods and hardware obsolescence reports are actively managed and reviewed to drive the refresh of assets nearing End of Support, thereby ensuring the reliability and performance of IT assets.

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[12] Excludes Volume of Enterprise Data Storage as the unit of measure is terabytes ("TB").
[13] Leslie Fiering, *PC Hardware Replacement Strategies: Planning Considerations* (Gartner, 2012).

Performance

When an application is placed into service, it is assigned a Support Level ("SL") designation. The SL contains a set of characteristics and performance expectations that determine the standards to which each application will subsequently be maintained to achieve a desired system availability. In 2017 actual availability exceeded expected levels as shown in Table 28 below.

Table 28 - Uptime Expectations by IT Support Level

Support Level	Expected System Availability	Minimum System Availability	2017Actual System Availability	Hours of Operation
SL-1	99.91%	99.53%	99.99%	7x24x365
SL-2	97.30%	95.25%	100.0%	7x24x365
SL-3	99.55%*	97.15%*	100.0%	Mon. - Fri. x Business Hours x 6:00 – 18:00

** Higher than SL-2 as Hours of Operation are Business Hours only. No single outage of a SL-1 or SL-2 Application shall exceed thirty cumulative minutes during any measurement window.*

In addition to vendor warranty and support, business requirements, employee productivity, and system health and performance are contributing factors when determining the need and rate of the replacement of IT assets, the latter of which is managed through software management and monitoring tools. It is the consideration of these factors that drive the lifecycle management of our IT assets.

Future Outlook / Need

Hydro One will continue to target a 99.5% uptime of key systems and associated data (SL-1) for customer service programs and work management programs linked to Hydro One Customer satisfaction goals/KPIs which are discussed further in TSP Section 1.5.

IT infrastructure needs will continue to be assessed to support and improve the cyber security posture of the company's assets based on the mandatory NERC version 5 and 6 standards. Where feasible, new technologies such as cloud computing solutions that eliminate server investments, will be adopted to lower IT costs.

Investment in MFA will continue as they reach the End of Support period to address warranty considerations, maintain hardware reliability and to meet business performance needs.

2.3 (5.3.3) ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES

Introduction

Lifecycle costs of transmission assets are the total costs of an asset throughout its useful life. The total costs are determined by using a corporate financial evaluation model that identifies the most cost-effective lifecycle management approach. This approach maximizes benefits to Hydro One and its customers during the asset service life, while balancing asset performance (including physical condition) and risks to Hydro One's business objectives.[1]

Based on this identified lifecycle management approach, Hydro One's lifecycle optimization policy describes various processes, procedures, and decision-making points relating to the management of transmission assets (e.g. planning, procurement, maintenance). Hydro One strives to ensure that all relevant processes and procedures are aligned with its optimization policy so that transmission assets are managed using a consistent approach.

Asset-specific strategies for transmission assets are based on the lifecycle approach. These strategies are meant to represent the operationalization of the asset lifecycle policy. Lifecycle strategies for assets such as stations equipment and lines include the following, but are not limited to:

- replacement approach and criteria (based on demand or planned replacement, conditions, technical obsolescence, environmental and other factors);
- approach to optimize repair/refurbishment versus replacement;
- maintenance criteria (e.g. preventive, corrective, time-based, condition-based, predictive; regulatory);

[1] See Section 2.1.2.1 of the TSP

- tools and training requirements;
- operational criteria and constraints that can impact asset life;
- spare parts requirements (entire units or specific components); and
- consideration for standardization of assets to optimize lifecycle costs and improve productivity.

Asset-specific strategies are reviewed periodically with the subject matter experts and updated on an ongoing basis, as needed. The lifecycle management strategy for each asset class must be considered from an overall power system perspective and cannot be considered in isolation. The strategy includes an evaluation of the failure modes, causes of individual component failures, consequences of asset failure, impacts on system performance and other corporate strategic objectives, such as environment, health and safety.

Asset information, which includes condition information, is periodically reviewed by subject matter experts to ensure quality and accuracy of the data, which in turn is used for the refinement and further development of the asset-specific strategies. As part of such review, subject matter experts may determine that some assets may require replacement due to new or increased demands on the system (such as higher load growth or increased generation connections) introduced partway through the lifecycle of the asset. For example, if a customer requests a larger capacity transformer due to their forecasted load growth, Hydro One will accommodate the request and the customer will be required to pay a capital contribution. In accordance with Section 6.3 of the Transmission System Code, the capital contribution will cover the difference in costs between the standard transformer that Hydro One would plan to install when the existing transformer reached its end of life, and the larger capacity transformer required to satisfy the customer request for incremental capacity. Asset utilization may be another factor used to evaluate asset replacement. For transformers, asset utilization takes into account the peak loading of the transformer compared to the transformer's capacity. There are circumstances where a transformer can be operated above its designed ratings or beyond its limited time rating for a period of time. If these situations result in operating constraints, the unit may be considered as a candidate for replacement.

Hydro One will also review the asset's historical loading and may decide to address the system's need with a like-for-like replacement or to install a new standard asset.

Typically, Hydro One replaces assets on a like-for-like basis. With respect to transformers, as an example, Hydro One considers the following factors before the decision to replace is made:

- any customer requests;
- the option of utilizing a different type and size of transformer to standardize the fleet which would reduce the number of operating spares required, while considering the implication of losses; and
- reconfiguring the station from a non-standard four transformer layout to a two-transformer layout to reduce asset count and footprint and increase operational efficiency.

Asset-specific strategies have been summarized in Table 1 below with references to the relevant sections in this Exhibit that outline their application.

Table 1 - Asset Strategy Summary

Section	Component	Asset Strategy
2.3.1.1	Transformers	Hydro One proactively inspects and monitors the transformer fleet to manage maintenance, monitor deterioration, remediate deficiencies and assess condition to determine the need for asset refurbishment or replacement on an individual basis. Asset assessment is based on risks inferred from demographics, condition, environmental settings, utilization, costs comparison between repair and replacement, and other lifecycle considerations.
2.3.1.2	Breakers	Hydro One performs routine maintenance and replaces breakers that are obsolete, pose safety risks, operate at or above their nameplate rating, exhibit unacceptable level of reliability performance, or have a poor environmental footprint in order to proactively address and prevent failure modes that could lead to outages.
2.3.1.3	Protection	Hydro One strives to maintain system reliability by ensuring the correct protective operation is initiated to isolate a faulted asset from the system. Hydro One performs preventive and corrective maintenance to ensure acceptable performance, maintain compliance, monitor deterioration and remediate deficiencies whenever technically and economically feasible.
2.3.1.4	Automation	Hydro One strives to ensure reliable functionality between its Control Centre and transmission assets by managing legacy obsolescence through timely replacement. As legacy automation equipment is replaced, it increases the standardization of asset and reduces corrective maintenance costs.
2.3.1.5	Power System Telecom	To ensure robust and reliable telecommunications for the protection, control and operation of the transmission system, Hydro One maintains and replaces power system telecom assets that pose a risk to reliability, safety or the environment.

Section	Component	Asset Strategy
2.3.1.6	Other Station Assets	Hydro One proactively manages assets through inspections and routine maintenance and monitors the fleet's condition to ensure compliance with regulatory bodies such as NERC, NPCC and the Ministry of Environment, Conservation and Parks. Repair vs. replacement assessments are done on an individual basis and are based on the risks that might arise from a demographic, condition, environmental, utilization, economic, and customer perspective. Such assessment balances the asset needs and risks as well as costs of the overall fleet.
2.3.2.1	Overhead Conductor	Hydro One manages the conductor population in a manner that maintains reliability and limits safety risk to acceptable levels. When a conductor, based on its condition as confirmed by testing, has been determined to have reached end of life, replacement is the only solution.
2.3.2.2	Underground Cables	Hydro One performs rigorous condition assessment and maintenance to maximize cable service life and replacing cables at end of life (EOL) where maintenance (repair) is no longer practical.
2.3.2.3	Steel Structures	Hydro One manages the fleet through a combination of planned structure replacements, component refurbishments and tower coating in order to maintain the reliability of the system and decrease the lifecycle costs.
2.3.2.3	Wood Pole Structures	Hydro One proactively replaces wood poles that are in poor condition, so as to reduce failures that impact customer reliability and safety, and to minimize emergency response activities. Hydro One uses a condition-based asset management strategy to sustain its wood pole fleet. Hydro One uses age of the wood pole as a criterion to identify the candidates for further assessment.
2.3.2.4	Insulators	Hydro One's primary focus is on the replacement of defective porcelain insulators that pose a high-risk to public safety, and end of life polymer insulators.
2.3.2.5	Rights of Way ("ROW")	Hydro One performs vegetation management on a cyclical basis. This asset strategy ensures all ROWs are regularly cleared to respect the applicable design width and to only contain compatible vegetation

Section	Component	Asset Strategy
2.3.2.6	Shieldwire	The asset strategy for shieldwire is to maintain system reliability and public and employee safety by replacing all shieldwire assessed to be at the end of useful service life.
2.3.2.7	Other Line Components	The asset strategy for other line components is to perform preventive maintenance and condition assessments along overhead transmission lines to identify defective equipment and components prior to failure. Hydro One executes corrective and demand maintenance to repair defective components, including end-of-life U-bolt and other hardware components. This strategy minimizes impact to customers, system reliability and public safety.
2.3.3.1	Facilities and Real Estate	Hydro One maintains facilities that are required for its operations by conducting planned maintenance of key facility systems and infrastructure. Hydro One undertakes regular inspections to identify any issues and undertake corrective maintenance where required. Hydro One conducts annual assessments to confirm facility requirements and, as necessary, complete renovations, additions, or replacements for new requirements and/or end of life condition.
2.3.3.2	Transport and Work Equipment (Fleet)	Hydro One strives to provide reliable equipment to employees so as to ensure the delivery of safe and economical services. Fleet Management Services and the Transmission and Stations line of business (“LOB”) complete a yearly review of all fleet and equipment that have met replacement factors against future work programs and staff needs.

Section	Component	Asset Strategy
2.3.3.3	Information Technology	Hydro One's strategy is to adhere to the IT industry standard practice. It includes managing hardware assets through a life cycle program ensuring vendor support is available and decreasing the likelihood of failure. Investment decisions are based on software life cycles, vendor schedules, reliability requirements, customer requirements, and experience with similar equipment. Hydro One replaces or upgrades applications where required to ensure continued vendor support and compatibility with the current IT environment. The primary goal is to minimize business interruptions. Investment decisions are based on return on investments calculations which reflect savings and constraints of software life cycles, vendor schedules and, reliability requirements.

2.3.1 (5.3.3 A, B) ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES – TRANSMISSION STATIONS

This section discusses the lifecycle optimization policies and practices for assets that are found in transmission stations, which includes transformers, breakers, protection schemes, control and monitoring equipment, power system telecom equipment, switches, capacitor banks, instrument transformers, ancillary equipment and civil structures.

2.3.1.1 TRANSFORMERS

Hydro One performs both Preventive Maintenance and Corrective Maintenance activities to proactively verify condition, monitor deterioration, and remediate deficiencies of its transformer fleet when it is technically feasible and economical.

Asset Strategy

Hydro One's asset strategy is to proactively inspect and monitor the transformer fleet. This allows the Company to manage maintenance needs and assess the transformer's condition as a factor to determine the need for asset refurbishment. Assessments to repair or replace transformers are done on an individual basis. The assessment is based on risks identified from condition, performance, utilization, demographics, criticality and environmental factors as well as cost comparison between refurbishment and replacement, and any other lifecycle considerations. Units in poor condition, with known manufacturing defects/obsolescence, or with anticipated higher repair costs, are prioritized for replacement.

Transformers that do not meet criteria for replacement within the next five years, particularly those that have reported severe oil leaks, or those with proven PCB concerns, will be prioritized for refurbishment. Hydro One's annual oil leak refurbishment rate averages about 1% to 1.5% of its transformer fleet. The refurbishment rate is subject to pacing of capital investment and the rate of leak development considerations.

Testing & Maintenance Practices

Preventive Maintenance

Preventive Maintenance consists of time-based activities that are in the manufacturer's manual, industry technical reports and Hydro One's operating experience. Asset condition information collected during maintenance enables further analysis for assessing corrective work requirements and adjusting future maintenance needs. Based on the condition information collected, Hydro One implements condition-based preventive maintenance strategies in parallel with its time-based maintenance to mitigate known risks that can be reasonably expected to materialize in the future. For example, tap changer internal inspections are primarily initiated from counter readings, which are collected from Hydro One's time-based station inspection. Hydro One believes that the changes to maintenance work from transitioning to increased online monitoring activities will be beneficial in the future, once Hydro One completes its full assessment.

Hydro One performs the following Preventive Maintenance activities with respect to transformers:

Table 2 - Transformer Testing and Maintenance Summary

Maintenance	Frequency	Description
Visual Testing	Bi-annual	Visual and audible deficiency inspection.
Oil Testing	6 months - Annual	Analysis of dissolved gas ("DGA") and oil quality to evaluate transformer condition.
Diagnostic Level 1	4 years	Function testing of transformer sub-components to verify correct operation.
Diagnostic Level 2	8 years	Replacement of the Gas Accumulation Relay and associated cable.
Power Factor Test (Doble Test)	8 years	Assessment of the transformer and the insulating condition of its bushings.
Selective Intrusive (SI) Inspection	4-8 years	Condition inspection of all internal components, contacts and mechanisms.
Oil Filter Change	2 years	Replacement of the under-load tap changer filter.

In addition to routine preventive maintenance, Hydro One also performs special diagnostic tests as required for troubleshooting purposes. These tests include:

- Transformer Turn Ratio Test - This test confirms that the transformer has the correct ratio of primary turns to secondary turns. This test can help to identify tap changer performance concerns, shorted turns, open windings, incorrect winding connections and other faults inside the transformer.
- Transformer Winding Resistance Test - This test measures the resistance of the winding to verify that connections are correct. This test is commonly used to identify tap changer performance concerns and detect any poor or open connections.

Corrective Maintenance

Hydro One performs Corrective Maintenance to remediate defects reported during routine inspection and testing. Hydro One remediates defects on a timely basis provided that the remediation is feasible, will preserve the life of the asset, and provides assurance that the asset will continue to economically meet existing operating requirements. If remediation or repair is not feasible, Hydro One will assess the need for demand replacement.

Hydro One has the following three kinds of commonly performed corrective maintenance activities:

- Oil Leak Repair

Natural gasket deterioration over time will cause oil to leak from the transformer. Oil leaks create environmental concerns (leading to potentially costly remediation and repairs) and can negatively impact reliability. Oil leak reduction requires case by case scoping to target leaking areas. Typical work scopes include oil handling, gasket replacement, gas relay piping upgrade, pump overhauls and radiator valve re-packing.

- Tap Changer Troubleshooting

A tap changer is a mechanical device that is an integral part of modern power transformer to provide voltage regulation in response to loading changes throughout the day. Tap changers can experience a wide range of mechanical and operational problems including tap changer being out-of-step, tap changer lockout, mechanical fatigue on motor drive parts, and deficiencies with current carrying parts. These deficiencies will impair the normal voltage regulation functionality that the tap changer provides. Maintenance and inspection intervals are determined by manufacturer's recommendations, and equipment specific performance determined by time in-service and operation count. Tap changer repair work may include anything from cleaning the control relay contact to removal and overhaul of the entire assembly.

- Cooling Failure Troubleshooting

Transformers rely on cooling fans and pumps to provide necessary cooling in order to achieve a higher loading limit, up to its full nameplate MVA rated cooled operation. A non-functional cooling system will force the transformer to operate at reduced loading capacity. Subject to the load transfer capability and loading profile of individual stations, operating a transformer at reduced capacity risks the station's ability to meet customer load demand. Typical remediation includes contact cleaning, replacing individual fans or even complete banks of fans.

Outlook Implementation

Hydro One continues to enhance its practice for maintenance and monitoring of transformer assets to ensure that the best industry practices are employed. Over the next 10 years, Hydro One plans to adopt the following measures to enhance its maintenance and monitoring activities for transformer assets:

Greater Use of Online Monitoring Systems:

Traditional transformer maintenance involves sampling transformer insulating oil on a periodic basis, usually from 6 months to 1 year intervals. Online Dissolved Gas Analysis ("DGA") monitoring devices can withdraw and analyse oil samples several times per day and provide real-time warnings to prevent transformer failure. Such devices are installed close to the main transformer units and are capable of withdrawing and analyzing oil samples from the main tank via installed piping at regular interval. Some include internal temperature monitors on transformers that provide real time loading feedback as well as utilization history. Due to cost and reliability concerns, Hydro One has only used online DGA devices on mission-critical units, which require special monitoring due to suspected defects, or units with very high replacement costs. Over the past decade, the accuracy, reliability and capability of these monitoring devices have improved and their cost has come down. Hydro One has a dedicated program to install and upgrade online DGA devices on larger power transformers and critical units, while online partial discharge monitors that detect abnormal electrical discharges are also being evaluated and considered.

Condition Based Maintenance Approach

Traditional preventive maintenance practices are largely time based. This includes the collection of condition and utilization data. As more data becomes available through online monitoring devices, Hydro One can adjust its maintenance plans to focus the required condition-triggered maintenance, while alleviating the need of time-based maintenance. Some tap changers are also equipped with fibre-optic monitors which can supervise the safe switching of the tap changer and provide leading condition indicators for any further inspections and maintenance.

Oil Leak Repair Sealant

Traditional transformer oil leak repairs are invasive, costly and lengthy. Hydro One has been evaluating and implementing the use of a sealant that can be injected between gaskets as an oil leak repair alternative, in cases where it is feasible and cost effective compared to traditional oil leak repair approaches. This method of repair can help avoid costly and time-consuming procedures related to oil processing during transformer repair.

2.3.1.2 CIRCUIT BREAKERS

Breaker testing is conducted to ensure the proper mechanical operation and electrical integrity of Hydro One's breaker fleet, in order to mitigate the possibility of a breaker's failure to interrupt fault current when called upon.

Asset Strategy

Hydro One performs routine maintenance and replaces breakers that are obsolete, pose safety risks, operate at or above their nameplate rating, exhibit unacceptable level of reliability performance, or have a poor environmental footprint (e.g., leaking Sulphur Hexafluoride ("SF6") or containing PCB levels in excess of regulatory criteria). Maintenance tasks facilitate the collection of diagnostic information on breakers to assess their health and need for overhaul or replacement. In addition, maintenance packages include tasks to proactively address and prevent failure modes that could lead to outages.

Testing & Maintenance Practices

Hydro One's maintenance practices are informed by manufacturers' maintenance manuals, industry technical reports and the Company's maintenance experience. The following maintenance packages are generally applied to circuit breakers:

Table 3 - Breaker Testing & Maintenance Summary

Maintenance	Frequency	Description
Visual Inspection	Bi-annual	Visual and audible inspection of external and ancillary components
Diagnostic Testing	6-7 years	Function testing to assess the breaker performance
Selective Intrusive (SI) Inspection	12-14 years,	Internal inspection, cleaning and replacement of worn components

Maintenance	Frequency	Description
Oil Analysis	1-3 years	Analysis of oil samples to assess the condition of an oil breaker's internal components
Power Factor Test	12-14 years	Condition assessment of live tank and oil breaker insulating components
Moisture Content Test	Bi-annual	Assess and manage moisture content within air blast breakers and some SF6 breakers.
Maintenance Level 1	3 years	Assess the performance and condition of pneumatic systems and comply with the Technical Standards & Safety Authority's requirements

Replacing breakers that are based on obsolete technology eliminates maintenance activities that are no longer required for modern breakers. Examples include the elimination of air blast breakers and the replacement of pneumatic mechanisms with simpler mechanisms.

Where spare parts are difficult to obtain or are no longer commercially available, sustainment of associated breaker fleets will be achieved by harvesting subcomponents from decommissioned units until the remaining fleet can be replaced. Where breakers exhibit unacceptable performance that cannot be resolved with a reasonable level of maintenance, these breakers will be targeted for replacement.

Bushings from oil circuit breakers need to undergo oil retro-fill or replacement in order to satisfy federal PCB regulatory requirements[2] by 2025 for equipment containing concentrations of PCB greater than 50 parts per million ("ppm"). All transmission station oil-filled equipment manufactured prior to 1985 must be sampled by the end of 2020, so that the PCB contained in such equipment can be removed or retro-filled to less than 45 ppm[3] by the end of 2024. The aforementioned timeline has been adopted by Hydro One

[2] Canadian Environmental Protection Act, 1999 - PCB Regulations SOR/2008-273.
[3] The 45 ppm criteria was established by Hydro One to account for any uncertainties in measurement and to ensure the federal criteria of 50 ppm is met with a high confidence level

to allow for a one-year buffer period, during which any issues that might arise can be rectified before the Environment Canada deadline of December 31, 2025.

Outlook Implementation

Hydro One's plan prioritizes breaker replacements based on obsolescence, vendor support availability, poor performance, environmental footprint, system criticality and safety risk.

To assess the changes in short circuit levels due to system upgrades and new or modified customer connection facilities, Hydro One performs project-specific short circuit studies to evaluate the increase in short circuit levels and identifies any required breaker upgrades as part of the Independent Electricity System Operator ("IESO") Connection Assessment and Approval ("CAA") process. Where short circuit level is exceeded, breakers need to be upgraded to higher short circuit rating, since operating beyond the nameplate rating can cause the breaker to fail.

SF6 is a colourless gas and conventional leak detection methods require the power equipment to be taken out of service, followed by the use of soap or bags placed over the suspected leak to look for bubbling from the leak, which can take many hours or days. Hydro One is exploring technologies to resolve SF6 leaks, such as the use of SF6 cameras to detect leaks prior to taking breakers out of service. This may lead to reduced outage times and improved work planning.

Alternatives to O-ring replacements are being explored in order to reduce outage times, repair costs and minimize poor performance until the asset can be retired. Deteriorated O-rings can cause leaks of the insulating medium and possible ingress of moisture, leading to a degradation of dielectric properties. If determined to be feasible, alternatives to O-ring replacement, such as sealant injection, may allow for shorter repairs that are less labour intensive in nature.

First trip testers are being explored as a diagnostic tool to detect intermittent mechanical issues without removing breakers from service. The device can assist in diagnosing if breaker operating time is beyond applicable limits due to issues with the trip/close coil or main mechanism. It can also help detect the condition of the DC supply and the existence of any sticky or faulty circuit breaker auxiliary contacts.

A non-operational data network is being established to collect and store data that is not required for day to day operations, such as diagnostic information. By facilitating the collection of such maintenance data, the operational data network would support more informed condition-based maintenance decisions. For more details on this investment, refer to ISD GP-05 - *Transmission Non-Operational Data Management System*.

Hydro One is exploring the use of online monitoring on circuit breakers using dedicated electronic devices to collect breaker performance information automatically and more frequently. These monitors would reduce the need for manual condition assessments and support greater use of condition-based maintenance rather than time-based maintenance.

2.3.1.3 PROTECTION

Protective relays and associated systems are critical in sensing and responding to abnormal system conditions. These devices protect local supply as well as supply within Ontario's Bulk Electric System ("BES") and mitigate the potential impact of abnormal conditions to the rest of the interconnected grid.

Asset Strategy

Hydro One's strategy for protection relays and protection schemes is to maintain system reliability by ensuring the correct protective operation is initiated to isolate a faulted asset from the system. To this end, Hydro One performs both preventive and corrective maintenance to ensure acceptable performance, monitors deterioration and remediates deficiencies whenever technically and economically feasible. The type and frequency of maintenance often depend on the type of protection system, the type of power system asset being protected, and the criticality of that asset. A number of North American Electric Reliability ("NERC") and Northeast Power Coordinating Council ("NPCC") standards govern the protection system maintenance program, including:

- PRC-004 *Protection System Misoperation Identification and Correction* – Purpose of this standard is to identify and correct the causes of protection system misoperations for BES elements.
- PRC-005 *Transmission and Generation Protection System Maintenance and Testing* - Purpose of this standard is to document and implement programs for the maintenance of all protection systems affecting the reliability of the BES so that they are kept in proper working order.
- PRC-012 *Remedial Action Schemes* - Purpose of this standard is to ensure that Remedial Action Schemes do not introduce unintentional or unacceptable reliability risks to the BES.
- NPCC Regional Reliability Reference Directory # 4 – *System Protection Criteria* – This document provides the design criteria for bulk power system protection within the service territories of NPCC member organizations.
- NPCC Regional Reliability Reference Directory # 7 - *Special Protection Systems* - This document provides the basic criteria for Special Protection Systems to ensure the reliable operations of the bulk power system.
- NPCC Regional Reliability Reference Directory # 8 - *System Restoration* - This document sets out the requirements for performing bulk power system restoration.

One of the greatest sustainment challenges for protection systems is the short vendor support time. Reduced duration of vendor support has significant adverse impact in terms of asset lifecycle management. For example:

- In 2013, one of the leading relay suppliers issued end of life notices for its Intelligent Electronic Devices ("IED"), also known as microprocessor based relays, with firmware which were up to 15 years old at that time. This only allowed Hydro One 6 months to procure any spare units that might have been available.

- Certain cyber-security related firmware features lost vendor support when the age of the firmware reached or just exceeded 10 years. To ensure compliance with cyber security standards, Hydro One had to replace the firmware before it reached Expected Service Life ("ESL").
- Lack of parts due to short support windows renders defects irreparable and forces the replacement decisions to be made before the end of the 20 year ESL.

The duration of vendor support continues to trend lower, which is largely driven by their own parts sourcing issues, faster technology changes as well as functional advances that manufacturers make for competitiveness. This problem is further complicated with ongoing changes to network connection standards that limit like-for-like replacements. A consequence of this problem is that some large North American utilities are already considering a shorter ESL for IEDs with typical values ranging from 15 to 20 years. Some utilities have gone further to announce the expected adoption of even shorter lifecycles.

Hydro One has decided to manage this issue rather than simply accept the downward trend. In this regard, as part of the procurement process, Hydro One is working with suppliers to gain extended support for their products so as to ensure the viability of its strategy to maintain ESL at 20 years. Given that the asset age versus ESL ratio is one input into the replacement decision, every year of ESL gained represents a better probability for the reduction or deferral of planned capital investments.

With respect to protection replacements, Hydro One's strategy is to target protections with a high likelihood of failure. Since the condition of this class of asset cannot easily be monitored, other factors are used as triggers for replacement decision, including:

increased failure rates related to specific models or families of devices, limited or non-existent manufacturer support (i.e. in terms of the provision of spare parts and repair services), and the inability to comply with current reliability standards.

Testing & Maintenance Practices

Preventive Maintenance

Preventive Maintenance involves time based routine testing or re-verification of protection systems. Protection systems spend most of their service life in a dormant state, yet must be relied upon to perform flawlessly during a fault or other abnormal system condition. Routine testing is the only means to maintain a high degree of certainty that the system will operate correctly when called upon.

The testing frequency of protection systems that are part of the BES is governed by applicable mandatory NERC standards.[4] For the remainder of its protection systems, Hydro One follows internal policies in accordance with good utility practice. Where a new microprocessor-based relay is installed, its self-monitoring capabilities allow the maintenance interval to be extended, which is also reflected in NERC standards.

In the past, Hydro One employed similar maintenance planning criteria for all protection systems, regardless of whether their maintenance was required by the applicable NERC standards. Additionally, Hydro One has adopted more aggressive maintenance frequencies than what NERC prescribes. This was done to mitigate the risk of non-compliance by providing some buffer to account for cases where regulatory maintenance cannot be performed on time due to operational and other reasons. Historically, the maintenance plans were aligned with maintenance cycles under an initiative where maintenance was performed on defined groups of equipment with the intent to mitigate

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[4] See: PRC-005- Transmission and Generation Protection System Maintenance and Testing and PRC-012 Remedial Action Schemes

customer outage impact. The alignment of protection maintenance was reviewed to achieve more cost-effective delivery of the maintenance program. Table 4 below summarizes the preventive maintenance schedules for protection systems.

Table 4 - Preventive Maintenance Intervals

	Regulatory Maintenance (Required by NERC or NPCC)[5]			**Timed Maintenance[6]**	
	Hydro One Maintenance Cycle (Years)		**Maximum Allowed Cycle by NERC**	**Non-Regulatory Maintenance**	
	Historical	**From 2019**		**Historical**	**From 2019**
Microprocessor Relays (non-feeder)	8	10	12	8	12
Electromechanical and solid state (non-feeder)	4	5	6	8	12
Microprocessor Relays (feeder) [7]	N/A	N/A	N/A	8	12
Electromechanical and solid state (feeder)	N/A	N/A	N/A	8	8
Breaker Trip Coil Tests (BTCT)[8]	4	4	6	N/A	N/A
Zone Test Tripping (ZTT)	4	8	12	8	8
ST3 - NPCC Directory #8[8]	5	5	5	N/A	N/A
Property Visual Inspection (PVI)[9]	N/A	N/A	N/A	3 or 8	3 or 8
Special Protection Transfer Tripping (SPTT)[8]	4	4	6	N/A	N/A

[5] Regulatory maintenance is performed on a subset of Hydro One protection system assets (approximately 40%) that are part of the BES system
[6] Timed maintenance covers maintenance of protections assets not included in BES system
[7] Maintenance of Hydro One's feeder protections is not required by NERC standards
[8] Tests performed on BES assets only
[9] No regulatory requirements for visual inspections to be performed. Interval of 3 or 8 years is selected based on the history of silver migration issues at a specific station.

Corrective Maintenance

Given the unplanned nature of failures or defects, there is variability as to the number and severity of corrective maintenance activities performed every year and these can be further split into the following two distinct groups: Emergency and Planned. Emergency corrective maintenance cannot be planned and involves remedying issues that occur during normal, everyday operations. Planned corrective maintenance proactively addresses known issues with certain makes and models of protection relays/systems, discovered from analysis of events, which may have an impact on other installations depending on the issue.

Support Processes and Systems

Hydro One maintains a set of support processes and systems for protection equipment. The support systems are in place to manage change control of the settings and configuration of protection and control systems, keep records of events, as well as manage the inventory and the re-seal schedule for revenue meters. Additionally, any protection operation requires field staff to validate and gather event records required for Natural Occurring Event Analysis (NOEA) investigations, which are mandated by NERC standard PRC-006 to determine whether the protection system performed as designed. When corrective maintenance involves a problem that exists in other locations, a program is created to remedy the deficiencies in all identified locations.

Outlook Implementation

In the past, electromechanical devices on Hydro One’s transmission network typically operate between 40-60 years before needing replacement. The ESL of modern microprocessor protection relays has been estimated at 20 years and an increase in failures is expected after that time. Systemic failures across whole platforms of protection relays have triggered a substantial increase in corrective maintenance and, in many cases, the need for large scale component replacements.

Given the demographics of Hydro One's protection system fleet and the condition trends and risks associated with equipment failures, a continued focus on replacement efforts is required to maintain system reliability performance. Modern protections include self-monitoring features which alert control room staff when they fail. The control room can then take appropriate action and dispatch crews to perform repairs. Old style relays, such as electromechanical relays, do not contain these features. Their malfunction can only be detected during routine maintenance or when they fail to perform as designed during system events. Because of this difference, NERC standard PRC-005 allows for an increased period between required testing of modern relays. For example, the PRC-005 maintenance cycle for electromechanical relays (no self-monitoring features) is 6 years; whereas modern microprocessor relays can be maintained once every 12 years, resulting in decreased Operations, Maintenance & Administration ("OM&A") costs associated with preventive maintenance.

Further, there might be other efficiencies to be gained through greater integration and application of new functionalities (i.e., functionalities that were previously built in but not utilized due to a lack of certain required enabling systems). Multiple initiatives, such as Remote Fault Data Collection, IEC 61850 Pilot and Distance to Fault Analysis, have already been rolled out to seize the opportunities that newer technologies are providing. Once fully implemented, these initiatives will allow Hydro One to utilize features already built into the relays to increase the ability to react to system events and/or reduce OM&A costs. For example, for every protection system operation, Hydro One dispatches field staff to download fault data and pass it to engineers for analysis. By being able to remotely access fault data from the IEDs, engineers will be able to obtain this data, thus reducing the cost associated with field staff dispatch.

2.3.1.4 AUTOMATION

Automation assets are highly complex electronic systems which integrate substation and switchyard devices. These systems enable the monitoring and control of power system assets and facilities at all times to achieve safe, reliable and efficient operation of the Ontario transmission grid. They also enable timely responses to emerging problems, real-time condition assessments, expedited restoration activities, and work planning.

Asset Strategy

The asset strategy for automation systems is to ensure reliable functionality of Hydro One's Control Centre such as monitoring and control, and the ability to remotely control and react to adverse power system situations. To ensure reliable functionality, Hydro One plans to manage legacy equipment obsolescence through timely replacement. The primary goal of replacements is to increase standardization across the modern automation system fleet. Moving away from different legacy variations will allow activities to be streamlined from a work management and lifecycle management perspective. Modern automation devices have far more powerful computational capabilities, allowing the consolidation of functionalities that were previously provided by multiple devices.

Through its automation strategy, Hydro One will evaluate changes in design architecture to maximize device functionalities and improve efficiency. Optimization is required as some legacy technologies are discontinued and reliability targets can be met with reduced redundancies or no redundancy in some cases.

As part of its automation asset lifecycle strategy, Hydro One, through the procurement process, will be working with automation product vendors in a similar manner as with protection IED vendors with the goal to avert a further shortening of product support windows.

Testing & Maintenance Practices

Legacy automation equipment requires preventive maintenance, such as replacement of subcomponents, to ensure operational availability. Maintenance is scheduled on a 7-year cycle for subcomponent replacement. In contrast, modern automation equipment requires significantly less maintenance and has embedded self-monitoring capabilities to provide performance alerts.

Corrective maintenance work for automation assets is reactive in nature and involves prioritizing and remedying issues that occur during everyday operations.

Outlook Implementation

With respect to its automation portfolio, Hydro One will focus on resolving known problems associated with the following equipment - RTUs, PSRs, LMCs, and LCCs, as further described below in this section. For example, direct Supervisory Control and Data Acquisition ("SCADA") will be implemented as a way to optimize the SCADA architecture. A new Transmission Non-operational Data Management System will provide a platform to realize efficiencies and cost savings related to maintenance.

Legacy automation systems primarily rely on a remote terminal unit ("RTU"), which is the core of the system. This equipment is based on the concept of physical wiring and digital conversion of electrical signals delivered by wires for SCADA purposes. The RTU equipment is expensive and labour intensive to install, modify and maintain. The equipment is generally built for a single function/application and does not offer much flexibility. From a communications perspective, these legacy systems utilize slow, serial, point-to-point connections and employ a variety of protocols. Failures of RTUs are considered very high risk as they can result in a complete loss of station functionality. Hydro One's goal is to move away from centralized RTU design as the costs are high and it does not offer a path towards substation modernization. RTU life is now being extended as much as possible while new, cost-effective solutions are being researched and developed. The goal is to land on modern I/O solutions with a small form factor, lower cost, and IP-based flexible scalability to match Hydro One's needs. Multiple technologies and standards are being examined as potential means to achieve this productivity and functionality improvement.

Legacy automation equipment contributes to about 80% of total defect costs and is likely to exhibit higher failure rates as the fleet ages and deteriorates, thereby increasing maintenance costs. Data shows that legacy systems are four times more likely than modern control systems to experience defects. Internal components degrade over time, which can adversely impact the performance of the automation equipment. This is primarily a concern with legacy systems along with the lack of vendor support and limited ability to provide replacement components. Hydro One plans to prioritize problematic high-risk installations (i.e., on the basis of statistics relating to failure/defect rates), which should be addressed before planned replacement.

Programmable Synchrocheck Relays (“PSR”) have been in-service for over 30 years. These relays were developed by Ontario Hydro’s research division, have an extremely high failure rate, require specialized expertise and tools to configure and are only single sourced due to their proprietary nature. Modern solutions will be used to replace these devices.

The Local Maintenance Computers (“LMC”) and Local Control Computers (“LCC”) exhibit high maintenance costs and require frequent software patching and updates. Hydro One plans to phase out these computers and replace them with modern solutions. Hydro One expects to minimize life cycle costs and address generic operating system vulnerabilities related to these computers.

Hydro One’s current SCADA network consists of approximately 40 hub sites that are used to facilitate communication of remote stations with control centres. They are no longer necessary as the communication protocols have been consolidated and the ability to communicate directly between a station and control centre now exists. Hydro One will be converting to the Direct SCADA architecture with the intent of removing the hub sites. Implementing Direct SCADA will provide improved reliability, performance, operational visibility and productivity as well as reduced costs and compliance obligations relating to NERC CIP standards since their functionality will be removed.

Hydro One is embarking on an initiative to implement a Transmission Non-Operational Data Management System to decrease costs by reducing maintenance, improve system availability, improve efficiency and automate dispatching of field resources. The system will enable the automatic collection of non-operational data (e.g., not used for day to day operations, but can relate to asset condition) at the substations to be processed in real-time and captured through a centralized enterprise system for further reporting and analytics. A key expected benefit of the system is the support of condition-based maintenance activities. More information can be found in the ISD GP-05 - *Transmission Non-Operational Data Management System*.

As part of its Condition-based Maintenance ("CBM") roadmap, which aims to maximize the number of stations subject to automatically managed CBM, Hydro One aims to implement a Computerized Maintenance Management System ("CMMS") with automated dispatch functionality that would automatically create maintenance work orders and communicate to field crews immediately upon detection of trouble conditions. This is a mature implementation of CBM which is expected to be implemented in future enhancement phases after the deployment of the Transmission Non-Operational Data Management System.

2.3.1.5 POWER SYSTEM TELECOM

Power System Telecom includes communication systems, infrastructure, and leased facilities that enable essential protection, control, monitoring, and operation of the transmission system in Ontario. Hydro One performs both preventive maintenance and corrective maintenance activities to proactively verify functionality, performance, monitor deterioration, and remediate deficiencies of all of Power System Telecom assets and systems to ensure their normal operational status. Hydro One also carries out strategic sparing as part of this essential asset maintenance.

Asset Strategy

Hydro One's asset strategy for Power System Telecom is to provide robust and reliable telecommunications for the protection, control and operation of the transmission system by maintaining and replacing assets that pose safety, reliability or environmental risks.

As part of its Power System Telecom asset lifecycle strategy, Hydro One will be working with vendors in a similar manner as with protection IED vendors, with the goal to avoid further shortened product support windows. Hydro One is also supporting wider industry initiatives in this domain.

Testing & Maintenance Practices

Hydro One's testing and maintenance practices for Power System Telecom assets include time-based preventive maintenance, emergency corrective maintenance and strategic sparing.

Time-based Preventive Maintenance

Hydro One maintains and field tests all communication system devices to verify that they are functional and meeting performance criteria. These are maintained under Hydro One's established Protection System Maintenance Program ("PSMP") which is based on NERC PRC-005, *Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance*. In addition, 48Vdc backup power supplies at certain sites (those identified by the IESO that are critical for restoration of Ontario's transmission system) are maintained as per NPCC Directory 8, *System Restoration*, requirements. More specifically, Telecom Preventive Maintenance involves the following maintenance activities:

1. **Routine Maintenance / Re-verification**. Routine maintenance is performed, among others, on the Synchronous Optical NETworking ("SONET") equipment, teleprotection terminal devices, PLC radios, and microwave radios. Maintenance includes visual inspections, air filter replacements (if applicable), verification of performance parameters and checks on alarm monitoring modules;
2. **Signal Adequacy Tests**. Signal adequacy testing performed on the PLC systems where the communication channels are unmonitored and don't have alarms.
3. **Radio Communication Tower Visual/Structural Inspection**. Communication towers are inspected visually for structural integrity and functioning of aviation obstruction lighting;
4. **Telecom Battery / Charger Maintenance**. Maintenance of 48Vdc batteries and chargers includes visual inspections, diagnostic test level 1 (equipment integrity check), diagnostic level 2 (AC interruption test) and battery load test;
5. **Auxiliary telecommunication equipment inspections**. Inspections of High-Voltage Interface ("HVI") equipment to verify their integrity (condition including rusting, leaking, equipment connections) and that they do not pose a risk to reliability and safety. Overhead metallic cables are inspected for wear and tear as well as any safety hazards; and
6. **OPGW / ADSS maintenance and inspections**. Aerial inspections of All-Dielectric Self-Supporting ("ADSS") cables which includes visual inspections for signs of excessive wear and other abnormal conditions of the cable as well as associated suspension assemblies.

Timing intervals for telecom maintenance are dependent on the technology of the communications scheme and/or equipment, and whether the telecom equipment directly interfaces with protection schemes that form part of the BES. For BES protection schemes, the maintenance of telecom devices is non-discretionary, and is based on the NERC PRC-005 standard, and requires annual compliance reporting. Maintenance on non-BES elements is performed on longer time intervals in line with industry best practices.

As Hydro One performs time-based preventive maintenance work, it tracks progress on a monthly basis and keeps maintenance records in a central repository. NERC and NPCC regulatory maintenance activities are reported on an internal monthly compliance scorecard. Unmonitored communication systems are tested for signal adequacy every four months and maintained/re-verified every six years while self-monitoring devices with remote alarming capabilities are maintained on a ten year interval. These maintenance intervals are stringent in order to mitigate the risk of non-compliance by providing some buffer to account for cases where regulatory maintenance cannot be achieved on time due to operational limitations.

Corrective Maintenance

Hydro One performs corrective maintenance to remedy defects identified during preventive maintenance and failure events. Corrective maintenance activities include fibre break repairs, telecom equipment repairs and diagnostic activities. Corrective work is prioritized based on the urgency of restoring the affected equipment. Maintenance of the provincial mobile radio system ("PMRS") equipment is contracted to a third party.

Strategic Sparing

Strategic sparing ensures that there are adequate operational spares available for all power system telecom assets, so that all categories of equipment can be maintained and repaired.

Strategic sparing also ensures that all materials and test equipment are available to meet the requirements of Hydro One's Fibre Cable Emergency Response and Restoration Plan. The following activities are included in power system telecom sparing programs:

- Procurement of operational spares for all power system telecom equipment;

- Ensuring fibre cable emergency response capability; and
- Providing maintenance support to field staff.

In addition to keeping track of failure rates and determining maximum and minimum stock levels, Hydro One also proactively monitors the equipment that have been discontinued and no longer supported by manufactures. Similar to other utilities, Hydro One is presented with “last buy opportunities” for strategic sparing of certain equipment in order to support the current installed base.

Outlook Implementation

Going forward, Hydro One will sustain assets to maintain reliability and meet communication system performance requirements. This will be achieved by systematically phasing out poor performing equipment from the asset base and working with suppliers to extended product support to reduce equipment obsolescence.

Hydro One is migrating its existing power system telecom services to new technologies. SONET and Provincial Mobile Radio System (“PMRS”) replacements will be sought with foresight to new application requirements such as non-operational data, remote condition-based monitoring and synchrophasor technology. ADSS cable and microwave system replacements will lead to less failures and performance issues leading to a more robust and reliable power system communication network. This will allow Hydro One to seek efficiencies by utilizing existing power system telecom infrastructure while maintaining reliability and OM&A costs associated with power system telecom services.

2.3.1.6 OTHER STATION COMPONENTS

Hydro One Transmission has numerous other station components categorized as other power equipment, other ancillary equipment, civil infrastructure and environmental management; which must be maintained to support the continued functionality of all major station assets.

Asset Strategy

With respect to this asset class, Hydro One's strategy is to proactively manage the asset fleet through inspections and routine maintenance to monitor condition and ensure compliance with applicable regulatory standards (including requirements of NERC/NPCC and Ministry of Environment, Conservation and Parks). Repair versus replacement assessments are done case-by-case based on the risk from a demographic, condition, environmental, utilization, economic, and customer perspective, as balanced against asset needs, asset reliability, safety risk and costs for the overall fleet. Additionally, decisions include the use of financial models to estimate the most economical option for the asset.

Testing & Maintenance Practices

Hydro One performs visual inspections, thermographic surveys and periodic testing of power and ancillary assets.

Other Power Equipment

Other power equipment mainly consists of HV/MV switches, capacitor banks and HV/MV Instrument transformers. Maintenance includes visual inspection for signs of external degradation such as chipped or cracked sub-components, thermographic testing, signs of corrosion and detection of other visual/audible issues (leaks, etc.). Where necessary, Hydro One schedules component replacement.

Ancillary Equipment

- AC/DC Station Service

On AC/DC station service equipment such as transfer schemes, switches and breakers, significant damage, deterioration, or loss of functionality identified through inspection or alarms are addressed through the appropriate remedial action. Consideration for more significant intervention, i.e. refurbishment or replacement of systems, would normally occur if a report indicated serious degradation. Inspections of AC station service breakers include manual operation tests, inspection of all internal components, insulation condition, contacts and rack-in mechanisms (where applicable).

- DC Batteries and Chargers

Hydro One maintains DC batteries and chargers by verifying functional and performance criteria according to regulatory standards governed by NERC PRC-005-02 and NPCC Directory 4 & 8 regulations. Diagnostics testing is performed every 12 months and battery load testing is performed every 3 to 5 years. As prescribed by applicable standards, maintenance activities include visual inspections and recording of critical battery and charger values. Other scheduled maintenance includes inspection of battery plate condition, conductance measurements, capacity and continuity testing of the DC system and battery load tests. Online battery monitors are being evaluated as an alternative to frequent testing activities.

- High Pressure Air System

Inspections include dryer and compressor condition checks, leak detection, verifying subcomponent operation, measuring dryer moisture content, and assessing and recording indicator, level and run time values. Other scheduled maintenance includes function testing, overhauling and component replacement where necessary. In compliance with Technical Standards and Safety Authority (“TSSA”) regulations, the pressure relief valve is tested every three to five years.

Civil Infrastructure

Visual inspections are performed to assess the condition and functionality of an array of assets including: below grade cable penetrations, station roadways, perimeter fencing/gates, structure footings/foundations, railway spur lines, site storm drainage, yard stone and cable trenches/trays. Also included is testing of building fire alarm systems and deluge systems where applicable; in compliance with the Fire Code and Ontario Building Code.

Environmental Management

Visual inspections are performed to assess the condition and functionality of spill control systems which include spill containment pits, passive/mechanical oil water separators, managing individual station environmental compliance approvals and any effluent testing/monitoring required in being compliant with the Ministry of Environment, Conservation and Parks.

Outlook Implementation

The outlook for other power equipment, ancillary equipment, environmental management and civil infrastructure varies due to differences in their respective functionality and modes of failure.

Other Power Equipment

Hydro One expects to see increased costs as ancillary systems are assessed to ensure compatibility with new station assets and regulatory compliance that require more frequent and stringent maintenance to be performed. Inspection work in advance of integrated replacement plans will identify when certain ancillary systems will not deliver safety and reliability benefits required for the new station asset arrangements and upgraded equipment.

Increased use of Drones for Outdoor Station Inspection

Drones are being used for both normal visual inspection and thermo-visual inspection. This is expected to allow for enhanced inspections of certain outdoor assets like switches and other equipment, which would help prevent outages that may increase customer interruption risks.

Battery Monitors

Batteries are a maintenance intensive item that may see improved reliability, safety and maintenance cost benefits from enhanced monitoring systems. Enhanced battery monitoring of conventional lead acid batteries will be installed and assessed for providing maintenance, safety and reliability benefits. This will also adhere to applicable compliance requirements.

The battery replacement program will focus on Valve Regulated Lead Acid ("VRLA") batteries due to the safety concerns they pose and the additional work protection required when working on these batteries.

High Pressure Air Systems-Reduced Population

Hydro One will continue to maintain high pressure air systems while air blast circuit breakers (ABCBs) remain in-service at stations. As the ABCBs are replaced with other technologies, maintenance costs are expected to decrease for high pressure air systems.

Environmental Management and Civil Infrastructure

Hydro one will continue to perform visual inspections and preventive maintenance to assess condition and functionality of assets in order to be safe, reliable and compliant.

2.3.2 (5.3.3 A, B) ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES – TRANSMISSION LINES

2.3.2.1 OVERHEAD CONDUCTOR

Asset Strategy

Overhead transmission conductors are designed to transmit electrical power safely, reliably and efficiently between nodes in an electrical system. Hydro One's strategy for this asset class is to manage the conductor population in a manner that maintains reliability and limits safety risk to acceptable levels.

Currently, Hydro One has 3,680 circuit km of overhead conductors that are known to be in high risk condition. This represents approximately 13% of the total overhead conductor population. Due to the increased risks these deteriorated assets pose, Hydro One has planned the replacement of approximately 2,127 circuit km of overhead conductors over the next five years.

When prioritizing replacement candidates, Hydro One considers condition assessment results, performance data, asset demographics and consequence of failure to the system and customer reliability. When test results conclude that a conductor has reached end of life ("EOL"), a line refurbishment project is initiated and incorporates the refurbishment of all deteriorated major components within the relevant line section, including structures, shieldwire, and insulators. Components that are in good condition are not refurbished or replaced. Based on the conductor condition assessment results over the next five years, Hydro One will re-evaluate and adjust the replacement rates.

Bundling conductor replacement with other components is a cost effective approach used when replacing conductors. The cost of deployment and mobilization of crews to perform line work represents a significant cost, and as such, when multiple tasks are performed in an area in a coordinated fashion significant economies of scope can be established.

Testing & Maintenance Practices

Deterioration of overhead conductors cannot be reversed. Therefore, these assets are tested and, where required, replaced in order to sustain the overhead transmission line system. Based on Hydro One's experience, testing practices have focused on assessing conductors that are greater than 50 years of age to identify segments that are high risk.

Hydro One is an industry leader in assessing the condition of transmission line assets, particularly aluminum conductor steel reinforced ("ACSR") conductors. Since the late 1980s, Hydro One has been using a conductor sample removal method combined with laboratory testing to assess the condition of conductors. As a result of making replacement decisions based on condition assessment, many good condition conductors that have aged beyond ESL are kept in service to safely and successfully operate beyond their ESL; and conversely, condition-based replacements also allow prematurely deteriorated conductors to be identified and addressed before they fail.

Recently, Hydro One started using the Kinectrics LineVue tool, which travels along energized and non-energized conductor span to measure the remaining cross-sectional area of the steel core wires in ACSR conductors. The tool allows for a greater number of condition assessments per year and is more cost efficient compared to removing conductor samples for laboratory testing.

Outlook Implementation

As discussed above, Hydro One has 3,680 circuit km of overhead conductors that have deteriorated and have been rated as high risk. For the next 5 years, Hydro One plans to prioritize the replacement of 2,127 circuit km of overhead conductors. The remaining 1,553 circuit km, along with any additional circuits that are identified as replacement candidates through planned condition assessment over the next five years, will be targeted for replacement in 2025 and beyond.

Hydro One is also evaluating EPRI's "C-corr" solution that can assess the condition of steel cores. This device is a non-contact tool that can be operated from the ground and does not require crew to physically ascend the tower structure. It is anticipated that C-corr will allow for more scans to be performed thereby reducing condition assessment costs for conductors. Given Hydro One's recent adoption of LineVue, C-corr would be adopted if it proves to be feasible and provides additional benefits for Hydro One in practice.

2.3.2.2 UNDERGROUND CABLES

Asset Strategy

Hydro One's cable strategy is to maximize service life, while maintaining current risk levels, to minimize capital replacement expenditures. This involves performing rigorous condition assessment, prioritizing maintenance and replacing cables at end of life where maintenance (repair) is no longer practical.

Testing & Maintenance Practices

Hydro One's maintenance programs are implemented to identify and repair deteriorated components as well as monitor cable health to provide insight into remaining life. Cable maintenance reduces the risk of cable equipment failure, which can seriously impact service and reliability. Deteriorated components are identified and monitored through a rigorous preventive maintenance (condition assessment) program. Routine preventive maintenance and more intrusive diagnostic tests have shown that many underground cables are in good operating condition. Refer to Figure 21 in TSP Section 2.2.2.2.

Preventive Maintenance

Preventive maintenance reduces the likelihood of premature cable degradation and failure, delivery point interruptions and oil leaks. Preventive maintenance activities are aimed at assessing cable condition and ensuring system reliability. Activities include: condition assessment patrols and routine testing/diagnostics of cables and ancillary equipment. Condition patrols and routine testing are done cyclically. The optimal frequency is based on industry best practices, historical experience and known asset deterioration rates. However, maintenance activities and their frequency are adjusted based on condition and reliability. Routine tasks include: vault inspections, oil tests and analysis, jacket tests, etc. Condition and test data collected by this program is used to determine the optimal timeframe for capital replacement.

Corrective Maintenance

Corrective maintenance activities are undertaken to investigate and repair cable and ancillary equipment deficiencies with the intent of returning the asset to its normal operable state. Deficiencies are typically noted during preventive maintenance condition assessments or trouble call responses. Demand corrective maintenance addresses repairs requiring immediate attention (i.e. emergencies) while planned corrective maintenance addresses less critical deficiencies not requiring immediate repair. Corrective maintenance activities include excavating and repairing cable components, and locating, repairing and the environmental remediation (clean-up) of oil leaks, etc.

In addition, supplemental non-routine tests are done on a demand basis to verify repairs and obtain detailed condition data if routine testing results show abnormalities. These non-routine tests are typically more intrusive (sometimes destructive), costly and require specialized equipment and external service providers. Where appropriate, this data can be used to increase the confidence in cable condition information, facilitating the selection and prioritization of replacement candidates.

Locates

Upon request, Hydro One is required by provincial legislation[10] to provide locate services for its underground infrastructure. The locate program covers the cost of field stakeouts and site representation of Hydro One's underground transmission system. This investment reduces the probability of underground transmission cable damage caused by dig-ins and the associated public safety risk.

Outlook Implementation

The fundamental objective of Hydro One's cable sustainment strategy is to maximize service life in order to minimize capital replacement expenditures. This is primarily done through preventive and corrective maintenance programs. Hydro One will continue to perform rigorous preventive maintenance and critical planned and demand repairs. Non-critical planned corrective maintenance and supplemental non-routine tests to obtain detailed condition data will be prioritized and/or deferred. While this deferral may result in an increased number of demand failure repairs, this risk will be mitigated through the prioritization of planned repairs. Furthermore, Hydro One will continue to replace end of life cables and ancillary equipment that can no longer be practically maintained. For example, widespread jacket deterioration and sheath corrosion (resulting in end of life conditions) are the driving factors for Low-Pressure Liquid-Filled ("LPLF") cable replacement.

2.3.2.3 STRUCTURES & FOUNDATIONS

Asset Strategy

Steel Structures

Hydro One's strategy for steel structures is to manage the fleet through a combination of planned structure replacements, component refurbishments and tower coating in order to maintain the reliability of the system and decrease life cycle costs. Structure

[10] Ontario Underground Infrastructure Notification System Act, 2012, S.O. 2012, c. 4

replacements and component refurbishments are usually part of bundled line refurbishment work.

Wood Poles

Hydro One's strategy for wood poles is to proactively replace wood poles in poor condition in order to reduce failures that impact customer reliability and to minimize emergency response activities. Hydro One uses a condition-based asset management strategy to sustain its fleet. Age is used as a criterion for determining assessment candidates only.

Foundations

Hydro One's strategy for transmission structure foundations is mainly focussed on repairing or replacing steel grillage footings and steel anchors, which are directly buried into the ground.

Testing & Maintenance Practices

Steel Structures

The condition of towers is determined through patrols, inspections, and detailed corrosion assessments. Towers are visually rated based on field guides[11] that have been developed in accordance with the National Association of Corrosion Engineers ("NACE"). Based on patrol results, a detailed engineering corrosion assessment is undertaken for severe cases to measure metal loss and assess bolts and fittings. The assessment also determines whether tower refurbishment and/or coating are necessary. Typically, 10% steel loss is usually the threshold that triggers refurbishment/replacement consideration.

[11] Field guides are tools that crews can use to decide how to rate the condition of a tower. The guides provide pictures and descriptions associated with certain rust levels and help to standardize the ratings between different crew members performing the assessment.

Hydro One's tower coating program aims to maintain steel tower structures at their design capacity by re-application of the coating approximately every 35 to 75 years. Tower coating is targeted for high corrosion zones, as classified under ISO 9223, where environmental factors give rise to high corrosivity.

If towers are not re-coated prior to an acceptable extent of strength loss (i.e., typically, before reaching 10% thickness loss), the opportunity is missed and the towers will ultimately have to be replaced or heavily refurbished at a significantly higher cost. Based on Hydro One's assessment and experience, tower coating has been one of the most economic and efficient methods of prolonging the service life of steel structures.

In light corrosion zones steel structures will likely be protected and maintained in good condition for a minimum of 115 years without requiring any additional coating. There are 39,250 steel structures (37,300 steel towers and 1,950 steel poles) in light corrosion zones but none of them are older than 115 years so there is no immediate tower coating planned within these zones.

Wood Poles

Wood poles are tested through the overhead line condition assessment program based on circuit age, known deficiencies, past failures and field recommendations. Aerial patrols are used to inspect the condition of the top of the pole, the cross arms and the associated hardware, while ground patrols and wood pole testing are used to assess the rest of the pole.

Wood pole inspections and tests results are assessed in accordance with Hydro One guidelines that set out the procedure and criteria for identifying end of life assets that warrant replacement. Performance data, asset demographics and the impact of failure to system and customer reliability are all considered when making replacement decisions for the yearly wood pole replacement program. This program aims to address wood poles confirmed to be at end of life.

Foundations

Tower foundations are assessed through the Transmission Lines Foundation and Anchor Assess, Clean and Coat Program (as discussed in Section 2.2.2.3) and line refurbishment projects. Based on the severity of corrosion, they are either cleaned and coated to re-establish the layer of protection or scheduled for future repairs/replacements. The Foundation Repair Program is used to complete repairs or replacements of foundations identified through the previous program.

Outlook Implementation

Steel Structures

The steel tower coating program has mainly been driven by economic considerations rather than risk mitigation. Based on the most recent analysis, the Net Present Value ("NPV") calculations show significant savings from tower coating versus tower replacement. Over the planning period, savings are estimated at $162M compared to single isolated tower replacements, or $101M compared to single tower replacements that are part of a multiple tower replacement project (i.e. replacing multiple towers is more efficient resulting in comparatively lower savings from tower coating). Based on reliability, safety, and environmental trade-offs, the current pacing of tower coating is approximately 500 towers per year. These towers are selected from structures that are already experiencing corrosion and metal loss.

At this rate, Hydro One expects to eliminate the tower coating backlog within 15-20 years, instead of the previously planned five years. While overall safety and reliability are not expected to be compromised under the revised pacing, the continuing aging of towers means that more work may be required in terms of surface preparation and/or structure member replacements before coating can be undertaken.

Hydro One currently uses live line work methods for tower coating on 230 kV circuits, which significantly reduces line outages. In some cases, compromised structure members will need to be replaced prior to tower coating, and depending on the deterioration, a complete tower replacement may be necessary.

Hydro One will continue using Rust Anode for the majority of the tower coating program. In the past three years, Hydro One has investigated and validated the use of Rust Anode as a recoating product, which has proven to be superior compared to the traditional Keeler Long paint. It requires less surface preparation work, dries quicker, and is a more robust treatment. The test results also showed that Rust Anode permits a higher number of towers to be coated with limited resources and outage windows. However, recent observations have shown that when a tower has corroded to a certain degree, even though it is still functionally sound, re-coating may not be economically and operationally feasible without intensive surface preparation. Hydro One and EPRI are re-evaluating current coating criteria to identify the optimal coating time and method to improve the performance and durability of Rust Anode coating.

Hydro One will continue working with EPRI to refine corrosion zones in Ontario by collecting and analyzing more data and increasing the resolution of the corrosion map. This will help Hydro One to improve its tower coating program.

Wood Poles

Hydro One plans to maintain current replacement levels in order to eliminate EOL structures over the next 10 years. This plan includes addressing the backlog of EOL structures, and newly identified EOL poles. This is expected to maintain the outage frequency and duration performance. Delaying these replacements increases the risk of failures, which could affect reliability and shift expenditures to the more costly demand emergency replacement program. Hydro One will continue to refine its data collection process related to the structure replacement and line refurbishment programs, thereby permitting an accurate depiction of the network inventory in order to improve decision making.

Solutions such as radar and laser technologies (involving helicopters and drones with HD cameras) continue to be explored in order to more efficiently detect wood poles and cross arms that are nearing EOL. Hydro One will consider utilizing steel and composite poles when replacing EOL wood pole structures because they have a greater life expectancy and lower life cycle costs.

Foundations

Hydro One will prioritize all grillage foundations of 500kV towers, and of 230kV / 115kV towers built before 1940, as they reach/approach EOL. At the current proposed pacing, the target is to complete the assess/clean/coat work for all grillage foundations by 2035. Poor condition grillage foundations can potentially contribute to tower collapse and significantly increase restoration costs.

Hydro One will develop a more specific maintenance strategy for concrete foundations, with input from EPRI and CEATI. In the meantime, concrete foundations identified yearly through foot or helicopter patrols will be scheduled for repair or replacement as required.

2.3.2.4 INSULATORS

Asset Strategy

Hydro One's insulator strategy is focussed on mitigating public safety risk by targeting defective porcelain insulators and end of life polymer insulators for replacement. Hydro One retained a third party expert, the Electric Power Research Institute ("EPRI"), to assess the condition of defective COB and CP porcelain insulators to assist Hydro One in determining the pacing of porcelain insulator replacement. The key recommendation made by EPRI is that the population of defective COB and CP insulators installed between 1965 and 1982 be removed from service as soon as practically possible. Defective porcelain insulators in publicly accessible (critical) areas are targeted for replacement by 2022, with the remaining defective insulators planned for replacement by 2027.

Testing & Maintenance Practices

Insulators cannot be maintained or repaired to extend the service life. They are assessed by using various methods and replaced when condition warrants the replacement. Condition assessment methods include visual inspections from the air or ground and are bundled with line and structure inspections and patrols; infrared thermography (thermo-vision) used to detect electrical insulation deficiencies; and electrical testing (polymer insulators only) using a live-working non-ceramic insulator testing tool to detect internal conductive defects.

Outlook Implementation

Insulators posing a higher public safety risk (i.e. insulators in critical locations) are to be replaced by 2022 at a rate of approximately 3,700 circuit structures per year. Insulators in non-publicly accessible areas will be replaced at an approximate rate of 3,450 circuit structures per year over a five year period beginning in 2022. Details on these programs can be found in TSP Sections 1.4, TSP 2.2.2.4 and ISD SR-25- *Transmission Line Insulator Replacement*. Replacement rates also take into account the urgency of the investment and practical pacing considerations (i.e. resource availability).

The replacement program includes polymer and other insulators however, these types of insulators constitute a small portion of the work program. The issues associated with polymer insulators are discussed in TSP Sections 1.4, TSP 2.2.2.4 and ISD SR-25 - *Transmission Line Insulator Replacement*.

2.3.2.5 RIGHTS OF WAY

Asset Strategy

Hydro One's Transmission Vegetation Management Program will be managed on a cyclical basis to ensure that all transmission right-of-ways ("ROW") are regularly cleared to Hydro One's Transmission Vegetation Management Standard. To meet this standard, Hydro One's ROWs are cleared to their designed width and all non-compatible vegetation on or adjacent to the ROW is removed.

Testing & Maintenance Practices

Hydro One's cyclical vegetation management program is primarily completed on a 6-year cycle in the East and Southern zones and on an 8-year cycle in the North. Some corridors in Eastern and Southern Ontario are maintained on a 4-year cycle due to faster vegetation growth rates. Maintenance is completed in Northern Ontario on a longer cycle due to the colder temperatures and slower vegetation growth rates.

Maintenance of Hydro One's ROW corridors consists of seven programs designed to identify and mitigate potential vegetation encroachments on energized overhead conductors. The seven programs are:

1. **Brush Control**: includes manual cutting, herbicide application and/or mechanical clearing to manage vegetation growth on the right-of-way to ensure adequate clearances and access to Hydro One's overhead circuits.
2. **Line Clearing**: consists of trimming tree branches and removing any unhealthy or danger trees on the edge of or adjacent to the right-of-way that have the potential to exceed Hydro One's clearances to the overhead transmission lines. Split, hanging, uprooted, dead and diseased trees are referred to as danger trees.
3. **Condition Patrol**: is mid-cycle working inspections which identify and mitigate any vegetation which requires maintenance prior to the next scheduled line clearing or brush control activity. ROW condition is also recorded and used to prioritize future maintenance activities.

4. **Property Owner Notifications**: Prior to the execution of ROW vegetation maintenance, Hydro One contacts all required adjacent property owners to communicate maintenance plans, obtain approval for access onto private property and acquire permission for the use of any herbicides to be applied during maintenance. Hydro One also actively engages all other external stakeholders, such as government agencies, municipal officials and special interest groups as required.
5. **Annual Vegetation Patrol**: in accordance with NERC standard FAC-003, Hydro One is required to annually inspect all of its circuits operating at a voltage of 230 kV or greater. Consequently, visual inspections by helicopter or ground are performed on all NERC applicable circuits not receiving Line Clearing or Condition Patrol maintenance in the current calendar year.
6. **Demand Maintenance**: addresses vegetation management issues that cannot wait until the next scheduled line clearing or brush control activity.
7. **Grounds Maintenance**: includes grass cutting, snow removal, garbage clean-up, and repair of access barriers and fences on Hydro One's urban ROWs, and is required to comply with local by-laws.

Outlook Implementation

Hydro One aims to operate an efficient vegetation management program while completing the regularly scheduled cyclical maintenance schedule. Postponement of vegetation management work increases reliability risks and results in a vegetation backlog that is harder and more costly to clear in the future.

Light Detection and Ranging ("LiDAR") is a remote sensing technology that is used by utilities to obtain accurate geospatial images and measurements of circuits and the vegetation surrounding them. Hydro One is exploring the use of LiDAR technology to obtain accurate measurements of circuits and the surrounding vegetation. Potential benefits and concerns associated with the technology and the value it offers the work program are currently being reviewed.

2.3.2.6 SHIELDWIRE

Asset Strategy

Hydro One's shieldwire asset strategy is to maintain system reliability and public and employee safety by actively replacing all shieldwire assessed to be at end of life. Hydro One uses a condition-based asset management strategy to assess and prioritize the replacement of its shieldwire fleet. Age is used as a criterion for determining assessment candidates only.

Testing & Maintenance Practices

Shieldwire cannot be maintained or repaired to extend life. Rather, Hydro One's shieldwire population is monitored through the condition assessment program and is replaced as condition warrants. Line sections of shieldwire are targeted for condition assessment after reaching an established age threshold, which varies between 25 and 50 years depending on the type, as illustrated in Table 5.

Table 5 - Shieldwire Condition Assessment Ages

Shieldwire Type	Age for Condition Assessment
Galvanized Steel	25 years
Alumoweld	40 years
ACSR	50 years
Copperweld	Not Required All Copperweld shieldwire is at EOL
Optical Ground Wire ("OPGW")	Condition assessment process for OPGW is currently being developed.

Traditionally, shieldwire condition assessment was conducted through laboratory testing of samples. Now, Hydro One primarily uses the Kinectrics LineVue inspection system to traverse along a span and assess the shieldwire condition. Data collected is used to estimate the remaining service life of the shieldwire without the need for an outage or intrusive testing.

Outlook Implementation

To maintain system reliability, Hydro One aims to ensure that all EOL shieldwire assets, identified through condition assessment, are scheduled for replacement in a timely manner.

EPRI has developed a non-contact device that is capable of identifying rusted shieldwire. While testing is still required to verify condition results obtained from this tool, it may potentially enhance future shieldwire condition assessment capabilities. Hydro One will evaluate the feasibility and practical benefits of this technology pending further testing results.

2.3.2.7 OTHER LINES COMPONENTS

Asset Strategy

The asset strategy for other lines components (e.g. U-bolts, downgrounds, bondwire, structure signs) is to perform preventive maintenance and condition assessments along overhead transmission lines to identify defective equipment and components prior to failure. Corrective and demand maintenance are executed to repair defective components, including EOL U-bolt and other hardware components and to minimize any customer impact, system reliability and public safety risk.

Testing & Maintenance Practices

Preventive Maintenance and Asset Assessment

The overhead lines maintenance program encompasses cyclical and non-cyclical based maintenance activities. Cyclical based maintenance activities include helicopter patrol, foot patrol, thermovision patrol, switch maintenance and insulator washing. Non-cyclical based activities include detailed helicopter inspection (“DHI”), climbing inspections and other asset assessment activities described in the corresponding sections for conductor, shieldwire, structures and insulator.

Cyclical Based Maintenance Activities

Helicopter and foot patrols are used to assess the condition of transmission line components. Helicopter patrols involve a high-speed patrol to identify major defects whereas foot patrols are a ground based patrol for circuits in no-fly regions. The optimal patrol cycle is either five or ten years for circuits that can be aerially inspected, or two years for circuits in no-fly regions.

Thermovision patrol identifies defective transmission line components by detecting their heat signature using infrared cameras. Switch maintenance inspects and maintains switch components, as well as verifies switch functionality on a ten year cycle. Insulator washing is performed on transmission structures located near urban highway and road crossings where salt contamination is a concern.

Non-cyclical Based Maintenance Activities

DHI involves a low-speed aerial-based patrol to assess the condition of tower structure hardware, including U-bolts and other smaller components such as dampers and clamps. Generally, DHI is performed on circuits older than 50 years and where U-bolt hardware has not been replaced in the past 50 years. Circuits that contain U-bolt hardware at 25% wear or more are to be re-assessed within 5 years from the time of the previous condition assessment. Circuits containing U-bolt hardware at less than 25% wear are to be re-assessed within 10 years from the time of the previous condition assessment.

Climbing inspections are performed on selected structures located in no-fly regions that cannot be inspected by helicopter. Typically, structures with higher public safety risk are selected. The general criteria to perform climbing inspection on a circuit section are similar to DHI.

Demand Maintenance

Demand maintenance is needed to respond to emergencies and to restore power when necessary. This program includes activities such as unplanned data collection, emergency component repair and trouble call response. This program also addresses problems identified during line patrols that need a near term response to prevent a potential outage or to address a serious safety issue.

Planned Corrective Maintenance and Projects

The planned corrective maintenance and projects includes minor corrective work and technical support, to resolve reliability and safety problems with transmission line assets. The planned corrective maintenance activities and projects are developed using the data collected during patrols and asset assessment activities, as well as information about equipment reliability performance.

Planned corrective maintenance addresses multiple line components including defective ground wire connections, missing or broken safety signs and nomenclature signs, U-bolt hardware that support the insulator strings and conductors; replacement of dampers that limit vibration of conductor.

Outlook Implementation

To minimize any customer impact, system reliability and public safety risk, Hydro One will continue to perform cyclical inspections to identify defects on the overhead line system as well as to perform asset condition assessment to identify EOL assets. EOL U-bolts identified through DHI or climbing inspection will be replaced through the planned corrective program or through other major component replacement programs. Out of approximately 123,500 circuit structures within the Hydro One transmission network, approximately 2,800 circuit structures have been identified with U-bolts in EOL condition and will require replacement. Defects with imminent reliability or safety risk will be addressed through the demand maintenance program.

2.3.3 (5.3.3 A, B) ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES – OTHER ASSETS

This section discusses the lifecycle optimization maintenance and replacement strategies for real estate and facilities, Transport and Work Equipment ("TWE") and Information Technology ("IT").

2.3.3.1 FACILITIES AND REAL ESTATE

An effective facilities management program is contingent upon identifying and prioritizing business and operational requirements. These requirements can range from minor capital repair or upgrade of existing facilities through to the establishment of a new work centre to address operational, business or regulatory requirements.

Asset Strategy

The asset strategy for Facilities and Real Estate is to maintain facilities that serve operational requirements in accordance with a lifecycle approach by conducting planned maintenance of key facility systems and infrastructure and undertake inspections at an appropriate frequency to identify and trigger corrective maintenance.

Facilities and Real Estate also conducts annual operational assessments with various lines of business to confirm facility requirements and, as necessary, complete renovations, additions or replacements for new requirements and/or end of life condition.

Testing & Maintenance Practices

Hydro One's facilities maintenance program is supported by visual inspections and Building Condition Assessments ("BCA") at planned frequencies. Execution of facility maintenance and inspections is outsourced to Brookfield Global Integrated Solutions ("BGIS") in accordance with Hydro One standards as well as industry specific standards relating to facility management. These standards involve operational and corporate-defined requirements, regulatory requirements and general commercial standards employed by the facilities industry.

Visual Inspections

Visual inspections are conducted at all facilities (with frequencies ranging from monthly to annual) to optimize performance. Each facility and its major sub-systems (e.g., HVAC, lighting, fire extinguishers, spill kits, eye wash stations, first aid kits and fences) are visually inspected on a monthly basis. Bi-monthly visual inspections are completed on the building envelope and site. Annual inspections address fire systems, building auxiliary systems, sewage system, and foundation and floor pads. Hydro One may carry out additional inspections as appropriate after events such as storms, earthquakes, fire, vandalism, or other relevant incidents.

Building Condition Assessments

BCAs are performed every five years to provide Hydro One with comprehensive insight on a facility’s condition. BCAs provide the life cycle analysis of each facility, forecasts expected performance and establishes the required short term, medium and long term investments for on-going operational requirements.

Project priority is based on timely and cost effective investments that serve system reliability, operational requirements, regulatory and corporate compliance, health and safety objectives. These priorities are established on the basis of asset condition assessments, frequency of trouble/corrective calls, business and operational risks (i.e. flooding, roof damage, etc.), and expanding/changing work programs or practices.

In line with the asset strategy, the results from the visual inspections and BCAs either trigger corrective maintenance, capital expenditure for renewal or replacement or are documented and re-evaluated in future planning with the lines of business (i.e. through annual operational assessments).

The level of corrective maintenance at each site depends on a combination of factors, including whether the site is owned or leased, the remaining estimated life of the asset, and future operational requirements. There is an exception with respect to Hydro One's leased facilities, where the burden of capital repairs and/or replacements resides with the lessor, other than those specific to Hydro One's operations, such as tenant improvements.

The operational assessment process entails conducting ongoing operational assessments with each line of business to ensure facilities are fully aligned with operational requirements and to identify and reaffirm planned investments. An annual planning meeting is conducted with each line of business to review their specific portfolio to identify facility requirements to current, planned or operational trends/strategies. As part of this review an opportunity/risk analysis is conducted to assist in the prioritization of facility requirements among the various lines of business.

In addition to the annual meeting, broader stakeholder meetings are conducted on a semi-annual basis with all lines of business. This provides each group with operational status updates of the various facility projects and initiatives in progress to confirm alignment with operational requirements. These stakeholder meetings may lead to the identification of operational synergies, such as co-location opportunities, so that different lines of business can leverage common infrastructure and facility elements. Periodic meetings are also conducted as needed to review newly identified corporate initiatives, which may impact the operational and facility requirements of the lines of business.

Outlook Implementation

Once the facility requirements are determined, Hydro One Facilities, in conjunction with BGIS, develops a capital investment plan to meet those operational requirements. Hydro One Facilities then analyzes the priorities and proposes a candidate investment. All of the accommodation needs, BCA data and infrastructure information are entered into a capital planning tracker where it undergoes various managerial reviews. In accordance with

Hydro One's arrangement with BGIS, continuous reviews are conducted pursuant to the scope of regular and periodic equipment inspections and building assessments, so as to improve the quality of BCA data with the objective of identifying equipment for repair or replacement prior to failure.

Hydro One Facilities aggregates the pool of candidate facility projects into a consolidated capital plan which undergoes a priority optimization in light of current, planned or operational trends and strategies. Feedback from internal stakeholders and management is then considered to further optimize the facility capital plan. The core responsibility of Hydro One Facilities is to preserve, maintain, and to maximize the useful life of capital investments. Facilities works with Hydro One lines of business to provide the requisite infrastructure that would allow employees to safely and effectively perform their job duties.

2.3.3.2 TRANSPORT AND WORK EQUIPMENT

Hydro One Fleet Management Services provides centralized and turnkey services that include equipment acquisitions, maintenance, administration, vehicle replacement and final disposition of Hydro One's Transport and Work Equipment ("TWE"), supporting the Transmission and Distribution workforce.

The main accountabilities of Fleet Management Services are to, among other things:

- Provide safe and reliable work equipment;
- Provide personnel transportation;
- Maintain cost effective equipment rates; and
- Adhere to engineering specifications and designs.

Asset Strategy

Fleet Management Services manages a fleet replacement capital investment program based on manufacturer recommended guidelines for end-of-life replacements. The TWE capital plan directly benefits Hydro One's customers by enabling lower overall work program costs. The availability of up to date and reliable TWE for work crews, when and where they need it, helps to reduce downtime and increase productivity while reducing maintenance costs associated with aging equipment.

Fleet Management Services and all Hydro One lines of business (including Distribution Lines, Forestry Operations, Transmission Lines, Stations Construction and Stations Services) complete a yearly review of all the equipment (including Fleet Maintenance Pool units that have met the manufacturer replacement guideline) against future work programs and staffing requirements. Telematics utilization data, which includes global positioning system ("GPS") data and a vehicle operation and performance data informatics system, is also considered in this review as an on-going initiative, to continually assess and right-size the fleet complement where possible.

In performing its asset management duties, Fleet Management Services considers a number of factors, including: equipment capital forecast; equipment productivity, functionality, and future requirements; equipment standards, equipment age, mechanical condition, kilometres traveled and cost per kilometre, downtime, and repair time; safety/risk; work programs; evaluating staff and equipment complement; tendered procurement process; fleet's original capital value and net book value; historical and future utilization; and strategic procurement when considering the replacement of an asset.

Helicopters are replaced on a case by case basis depending on utilization, condition of the aircraft and the cost of refurbishment. The strategy for the replacement of helicopters is designed to mitigate the risks of equipment failure, emergency response, work program repair time and costs as well as environmental impacts.

Testing & Maintenance Practices

Inspection and Maintenance Program

Fleet Management Services has developed a balanced maintenance model to efficiently service and repair equipment and minimize downtime. Work crews can arrange to have local mechanics provide service at their work sites or the asset can be towed to a centralized facility. There are 45 provincial maintenance hubs, shown in 1 below, that are strategically positioned throughout the province to provide a high quality service which minimizes response and travel time.

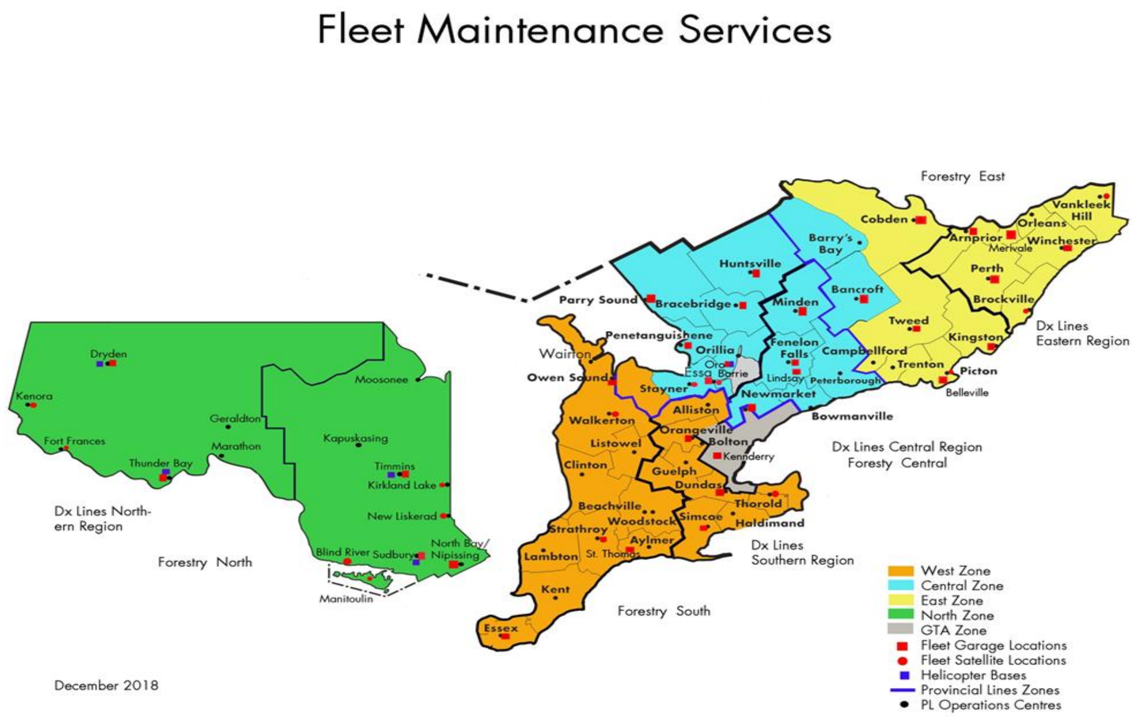

Figure 1 - Map of Fleet Garages and Helicopter Hangers

Fleet Management Services employs specialized heavy duty mechanics that inspect and repair heavy, off-road and miscellaneous equipment. Hydro One's skilled technicians and their service trucks provide timely on-site field support for various nomadic work programs, such as vegetation control, new construction and off-road tower maintenance.

The Hydro One garages are Motor Vehicle Inspection Stations licensed by the Ministry of Transportation.

For all light duty vehicles, Hydro One outsources all inspections, services and repairs. This approach allows Hydro One technicians to focus on the inspection and repairs of the specialized hydraulic equipment. All external vendors receive pre-approval from authorized personnel in Fleet Management Services prior to the commencement of any work.

For helicopters, Fleet Management Services has a team of experienced pilots and air maintenance engineers based in five strategic locations across the province to support the Hydro One lines of business, as shown in Figure 1 above. All pilots and air maintenance engineers hold Transport Canada licenses and receive annual training and testing to maintain a high level of proficiency.

Table 6 below summarizes the Fleet Maintenance Service Interval Guidelines for transport and work equipment.

Table 6 - Fleet Maintenance Service Interval Guidelines (Transport and Work Equipment)

Equipment Type	Lube, Oil, Filter			Dry Services	Type of work
	km	Engine Hours	Months	Months	
Light	8,000	-	6	N/A	• Service • Annual Inspection
Light - dual wheels	8,000	-	6	3	• Service • Annual Inspection • Attachment Inspection

Equipment Type	Lube, Oil, Filter			Dry Services	Type of work
	km	Engine Hours	Months	Months	
Heavy - Service Trucks, Compact Bucket trucks	8,000	200	6	3	• Service • Annual Inspection • Attachment Inspection
Heavy – RBD and Bucket Trucks	20,000	250-500	12	3	• Service • Annual Inspection • Attachment Inspection
Miscellaneous	-	250	12	3-6	• Service • Annual Inspection • Attachment Inspection

The Helicopter Service Intervals Guidelines include inspection and maintenance for the airframe, hydraulic servos, main gearbox, tail gearbox, engine, engine modules and fuel controls after a certain amount of flight hours. Complete refurbishment of the hydraulic servos, main gearbox, tail gearbox engine modules and fuel controls are also completed based on the flight hours or age of the unit.

Telematics

Fleet Management Services has implemented a fleet Telematics system in more than 4,700 of its fleet vehicles. Through its integrated telecommunications, GPS and informatics systems leveraging satellite and cellular data, Telematics provides the location of vehicles as well as live vehicle operation and performance data. Telematics also serves as a Driver Behaviour Modification System by educating and informing drivers of any speeding habits, harsh driving events and idling statistics. With on-going coaching and training, Hydro One has realized a reduction in speeding incidents of more than 80% and a reduction in harsh driving (sharp acceleration and harsh braking) incidents by more than 65% since the implementation of Telematics in 2016**.**

More specifically, the Telematics system provides the following benefits:

- Improves operator safety, fuel efficiency, and greenhouse gas reductions through increased awareness of driving habits (e.g. through reports regarding speeding, sharp acceleration, and harsh braking);
- Provides Fleet Management Services with important equipment data, including idling and utilization statistics, allowing for more informed decisions on the requirement of the assets and how they are being used;
- Improves Fleet Management Services' response time and security with the visibility of live vehicle locations as well as more efficient crew deployment during storm restorations;
- Improved Power Take Off fuel tax credit supporting documentation; and
- Improved visibility to the Engine Control Module for tracking of vehicle condition (where available).

Outlook Implementation

The TWE Replacement Program balances a five-year business planning cycle for capital investment requirements while maintaining a safe, reliable and cost effective fleet. It is imperative to evaluate and forecast spending requirements to minimize fluctuating spending patterns and to stabilize long term capital investment. A reduction in capital spending in a given year is likely to result in increased operating costs, which could ultimately result in increased equipment rates directly impacting the costs of the Transmission work programs.

Adoption of Technology for A More Cost Effective Fleet Complement

With the use of the Telematics technology, Fleet Management Services will continue to collect and leverage vehicle performance and utilization data, which will enable the continuous review of the fleet to ensure the optimal number of vehicles for future corporate work programs and staffing requirements.

2.3.3.3 INFORMATION TECHNOLOGY

Asset Strategy

The asset strategy for IT hardware is to adhere to the IT industry's standard practices to manage assets through a life cycle program and to ensure availability of vendor support. Investment decisions are made based on software life cycles, vendor schedules, reliability requirements, customer requirements, and experience with similar equipment.

In addition, the Asset Strategy for IT applications aims to perform replacements or upgrades as required, including to ensure compatibility with the current IT environment and minimize business interruptions. .

Testing & Maintenance Practices

Hydro One's practice is to replace IT Minor Fixed Assets (e.g., desktops, laptops, printers, plotters, rugged tablets, mobile devices) on cycles that range from every three to five years. The renewal timeline is consistent with industry best practices as outlined by leading technology analytics organizations. Hydro One strongly values and takes industry insight into consideration for its own IT strategies and practices.

Another factor governing replacement timelines is hardware maintenance costs which typically increase after the three to five-year expected life cycle period, thus making it a more appropriate time for hardware refresh. However, the refresh cycle has been adjusted to accommodate business requirements and may be necessitated by application upgrade projects performed on broadly used applications, such as Microsoft Windows, which have increased hardware requirements. Hydro One has implemented its current refresh cycles in order to minimize the overall life cycle costs of the assets. Refreshing equipment maintains or reduces maintenance costs as the cost of extending a warranty late in an asset's life is more costly than buying a warranty at the time of purchase. The ongoing maintenance and sustainment of Hydro One IT applications and the supporting infrastructure is outsourced to Inergi LP.

Lifecycle Optimization Policies and Practices

The following general architectural principles apply to all Hydro One IT applications:

- Applications will be commercial-off-the-shelf ("COTS") and maintained in a vendor-supported version lifecycle to ensure continued functionality and maximum longevity;
- Custom applications are migrated to COTS solutions wherever possible to minimize development, integration and maintenance costs;
- Where possible, application rationalization is applied to reduce the number of applications supported and lower support costs; and
- Middleware will be used to facilitate application interconnectivity. Hydro One has invested in implementing middleware or Service Oriented Architecture to enable data integration within and between applications to ensure continued interoperability.

There are a number of important and coincident factors that must be considered when determining whether an application should be upgraded/replaced. These include:

- age (lifecycle) of the existing application;
- complexity, cost and duration of the upgrade process;
- potential impact to the business (e.g. tolerance for downtime);
- risk, dependencies and potential impacts to other upstream or downstream applications;
- maintaining vendor supportability;
- providing enhanced business functionality/capability required by Hydro One; and
- integration with other applications.

Applications are replaced when they become inadequate for current functional needs; where the platform is no longer supported by the vendor; to address legislative changes or market driven initiatives; or to significantly modify the application to better support an evolving business capability. IT development projects enable the replacement and/or upgrade of end-of-life applications and may also include investments in new applications to meet changing business and customer requirements.

In determining when equipment requires replacement, Hydro One Assesses equipment's functionality, operating, and warranty maintenance costs. Spending varies depending upon hardware life cycles and business requirements for increased processing capacity. Lifecycles vary primarily depending on the demand for additional functionality from the applications being hosted or the expected failure rate provided by the vendor.

The strategic decisions to conduct system upgrades are largely based on industry standard Systems Development Life Cycle ("SDLC") methodologies. An SDLC is composed of a number of clearly defined and distinct work phases which are used to plan for, design, build, test, and deliver information systems. An SDLC aims to produce high-quality systems that meet or exceed customer expectations, based on customer requirements, by delivering systems which move through each phase, according to scheduled time frames and cost estimates.

Outlook - Implementation

Business planning is performed on an annual basis with business stakeholders to assess whether investments in business processes and IT technology are required. Projects are generally one of two types:

Investments in new functionality to meet business objectives

These investments include new or upgraded applications designed to improve functionality, customer support and efficiency. The projects may support other business objectives. Examples of these projects include:

- HR and Payroll Related Technology Investments (ISD GP-08 - *Corporate Services Transformation - HR / Payroll*);
- Transmission Customer Portal Enhancement; and
- Asset Analytics (re-platform and Flexible Asset Analytics).

Investments to replace or upgrade end-of-support applications

These investments address hardware/software deficiencies to support efficiency and performance. An example of this type of project is the S/4 HANA for Finance and Enterprise Asset Management (ISD GP-09 - *Corporate Services Transformation - Finance*) and Enterprise Geographical Information System.

3.0 (5.4.1 A, B) CAPITAL EXPENDITURE PLANNING OVERVIEW

Hydro One completes an annual detailed investment planning process to establish a plan that appropriately reflects customer needs and preferences, system and asset needs, and rate impacts. The planning process that ultimately leads to the investment levels set out in this TSP forms part of Hydro One's overall asset management process, which is aimed at identifying and scoping the optimal timing of capital investments and asset maintenance throughout the life cycle of assets. Hydro One's 2020-2024 capital expenditure plan is an ouput of its asset management framework, including outputs stemming from the investment planning process (as detailed in Section 2.1 of this TSP). In particular, the following considerations are key to the derivation, refinement and finalization of the capital expenditure plan:

- assessment of potential investment candidates through a systematic approach of scoring and calibration;
- enterprise engagement to ensure feasibility of funded portfolio with respect to operational and execution considerations; and
- pacing of work at an enterprise-level to appropriately reflect risk-based prioritization and optimization as well as productivity expectations.

Given that the specific activities associated with the aforementioned considerations are detailed in Section 2.1 of this TSP, the discussion below is intended to highlight the key features and enhancements relating to these activities that directly impact and underpin the 2020-2024 capital expenditure plan.

Over the past year, Hydro One has improved its investment planning process to provide a standardized, consistent and fact-based approach to cost-effectively maximize value for customers. The enhanced process includes the introduction of clear and consistent frameworks and scoring across candidate investments to build a capital expenditures plan that is reflective of asset needs, customer needs and preferences, and system needs.

These improvements are also intended to address feedback from a number of sources, including customer input and the Ontario Energy Board's (OEB) concerns from the EB-2016-0160 proceeding. Additionally, Hydro One has enhanced its approach to prioritization and optimization by introducing a series of challenge sessions to more effectively calibrate the priority assignments of candidate investments, address pacing concerns and properly define an investment portfolio based on risk and non-risk merits. These enhancements are further discussed below in relation to the key components of the capital expenditure planning process.

3.0.1 (5.4.1 A, B) INVESTMENT ASSESSMENT AND CALIBRATION

"Investment Assessment and Calibration" refers to Hydro One's process for assessing potential projects identified in the course of investment planning, including by evaluating the risk mitigation impact of investment candidates, assessing the expected impact on desired outcomes, and calibrating risk assessments to enable consistent decision making across the entire portfolio (see Section 2.1.5 of the TSP). A key enhancement to this process has been the introduction of multiple challenge sessions involving relevant lines of business, as a fact-based and holistic approach to considering project merits (both risk and non-risk based) and making trade-off decisions. This approach increases the rigour around the examination of proposed investments (particularly those that are on the margin) by a broad group of professionals and allows greater scrutiny of the investments that drive the overall budget. In addition, the following new features or enhancements were also implemented:

- **Flagging** – The introduction of new "flags" to represent special considerations or investment drivers (compliance, net prevent value, strategic, etc.) that are important to fact-based project scoring, and to ensure supporting documentation is provided.
- **Consistent frameworks –** The implementation of a seven-level framework (known as scoring "taxonomies") for consequence and probability analysis based

on quantified impacts across all risk dimensions (including by using an exponential scale that allows the two ends of scale to be more effectively differentiated).

- **Standardized scoring -** Scoring is based on three quantifiable risk criteria – safety, reliability, and environment. Consequence scores are based on worst reasonable direct impact as opposed to worst credible impact.
- **Calibration -** Ensures flags and scores are "calibrated" (i.e. to enable consistent assessments across investments) before, during and/or after scoring.

The revised process for scoring and calibrating potential investments was in part influenced by customer survey feedback. For instance, surveyed customers ranked safety, reliability, and environmental considerations as high priority risks[1], which are used as the three quantifiable criteria for standardized scoring. New flags for investments relating to customer service and productivity outcomes were also introduced to better evaluate and align investments relative to customer priorities.

Figure 1 below outlines the scoring results of four example investments included in the plan: Bruce A TS & Bruce B SS air blast circuit breaker ("ABCB") replacements, John TS station reinvestment and High Voltage ("HV") Underground ("UG") cable replacements. For more detailed information on each investment, please refer to SR-01 - *Air Blast Circuit Breaker Replacement Projects*; SR-08 - *John Transformer Station Reinvestment*; and SR-27 - *C5E/C7E Underground Cable Replacement*.

[1] On a priority scale of 1 to 10 (with 10 being the highest priority), over 80% of customers surveyed identified safety, reliability, or environmental considerations as a 7 or higher.

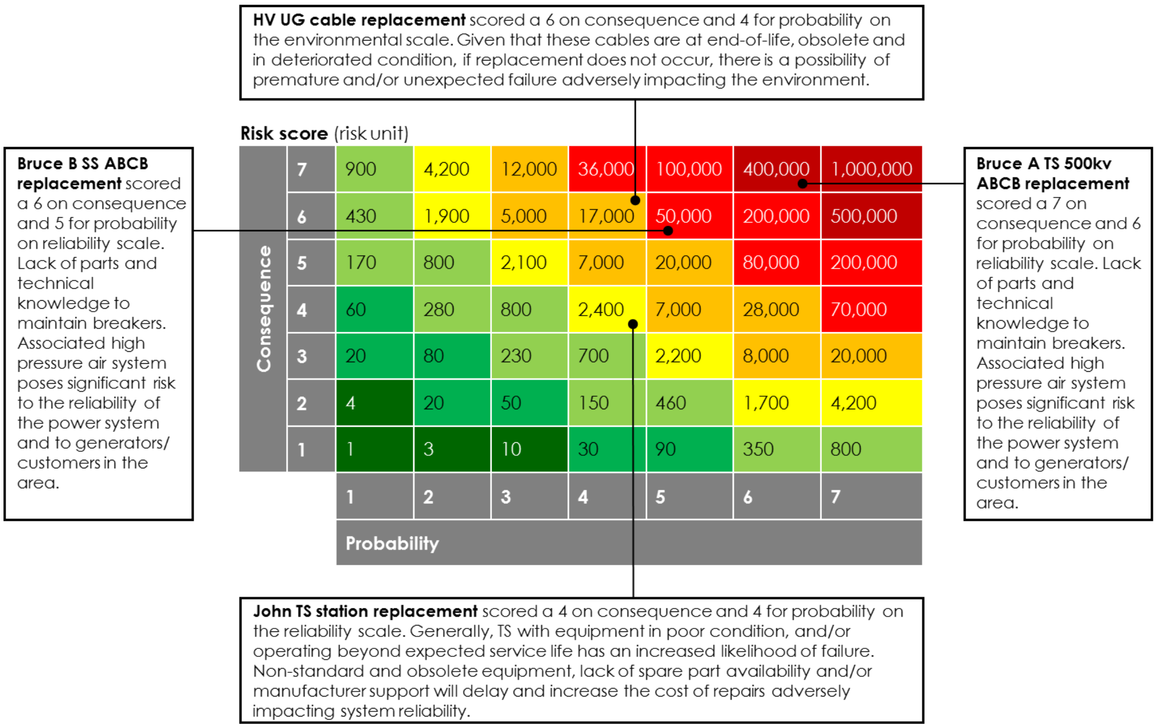

Figure 1 – Candidate Investment Scoring Examples

3.0.2 ENTERPRISE ENGAGEMENT

A lengthened "enterprise engagement" step was designed to (i) address the concerns raised in the EB-2016-0160 proceeding regarding Hydro One's ability to execute its proposed capital programs, and (ii) place more emphasis on collaboration between different levels and divisions of the organization. Engagement with the enterprise team and the incorporation of their input into the preparation of the final plan ensure that the funded portfolio will be feasible from an operational and execution perspective, which in turn mitigates potential risks in future investment delivery. For example, enterprise engagement led to the deferral of an investment at Havelock TS by two years in order to address emerging asset needs at Port Hope TS (see ISD SR-05).

3.0.3 (5.4.1 B) PACING

The effective pacing of the overall investment portfolio over the TSP period is crucial to establishing the final capital expenditure plan. Hydro One views enterprise-level pacing as a function of three elements: (i) overall spend, (ii) prioritization and optimization, and (iii) productivity. OEB staff previously submitted that the proper pacing of capital investments does not mean ignoring or minimizing an identified need but spreading out required investments to balance system needs and avoid sudden cost or rate impacts. Hydro One has addressed these concerns through the following actions:

- Overall spend: Hydro One's proposed budget envelope was set at a level below what was tested with customers, as evidenced in Sections 1.3 and 3.2 of this TSP. Hydro One agreed with customer feedback that this approach offered the appropriate balance between ratepayer costs and risk mitigation.
- Productivity: Through increased productivity, Hydro One has committed to deliver the same work program at a lower cost. New productivity initiatives continue to be identified but represent a commitment to continuous improvement across the organization.
- Prioritization and Optimization: Based on risk-based prioritization and optimization through the enhanced planning process, candidate investments that are expected to most effectively mitigate the highest risk for the least cost should be performed first. For example, this is demonstrated through the prioritization and optimization of capital station sustainment work at Port Hope TS (ISD SR-05) to address emerging asset needs over a candidate investment at Havelock TS.

3.1 (5.4.2, 5.4.3.1) CAPITAL EXPENDITURE SUMMARY

The capital expenditure plan set out in this Transmission System Plan ("TSP") is $1.2 billion for 2020. The plan increases to $1.4 billion in 2022 and plateaus from 2022 to 2024. This proposal represents approximately $6.6 billion in total capital expenditure over the five year TSP period and includes approximately $0.7 billion of capital productivity savings and improvements through information technology, procurement, and other process efficiencies[1]. The proposed plan balances: (i) asset-related needs of the transmission system arising from age, condition and environmental and regulatory compliance requirements; (ii) customer needs and preferences relating to reliability; (iii) regional infrastructure and broader system needs to address system constraints, enable new load growth, and facilitate access and new connections to the transmission system; and (iv) impact on customer rates.

Table 1 below summarizes the 2020-2024 capital expenditure plan which is detailed in this section of the TSP. Actual and forecast expenditures, by category, from 2015 to 2024 are presented in Figure 1 below and detailed in TSP Section 3.3. Note that the test period for this Application is 2020 to 2022.

[1] These amounts include approximately $0.3 billion in Progressive Productivity savings as shown in the Progressive Productivity Placeholder line of Figure 1 and detailed in TSP Section 1.6.

Table 1 - Forecast Period Capital Expenditure Summary

OEB Category	Forecast (Planned $M)				
	2020	**2021**	**2022**	**2023**	**2024**
System Access	24.8	11.3	11.7	12.7	4.1
System Renewal	865.2	1,103.1	1,172.8	1,177.4	1,193.8
System Service	204.1	148.2	151.8	174.3	204.2
General Plant	115.4	94.4	94.7	83.6	58.9
Progressive Productivity Placeholder	(17.0)	(39.0)	(61.0)	(78.0)	(91.0)
Directive Adjustment[2]	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)
Total	**1,192.2**	**1,317.7**	**1,369.6**	**1,369.6**	**1,369.6**
System OM&A[3, 4]	**375.8**	*	*	**N/A**	**N/A**

[2] The Directive Adjustment reflects the impact of the directive issued by Ontario's Management Board of Cabinet on February 21, 2019 and the associated compensation framework they approved on March 7, 2019. Refer to Exhibit F, Tab 4, Schedule 1 for further details.
[3] System OM&A includes Operations, Maintenance and Administration expenses. System OM&A for 2021 to 2022 is determined based on the escalation factor identified in Exhibit A, Tab 4, Schedule 1
[4] Includes the Directive Adjustment described in Exhibit F, Tab 1, Schedule 1.

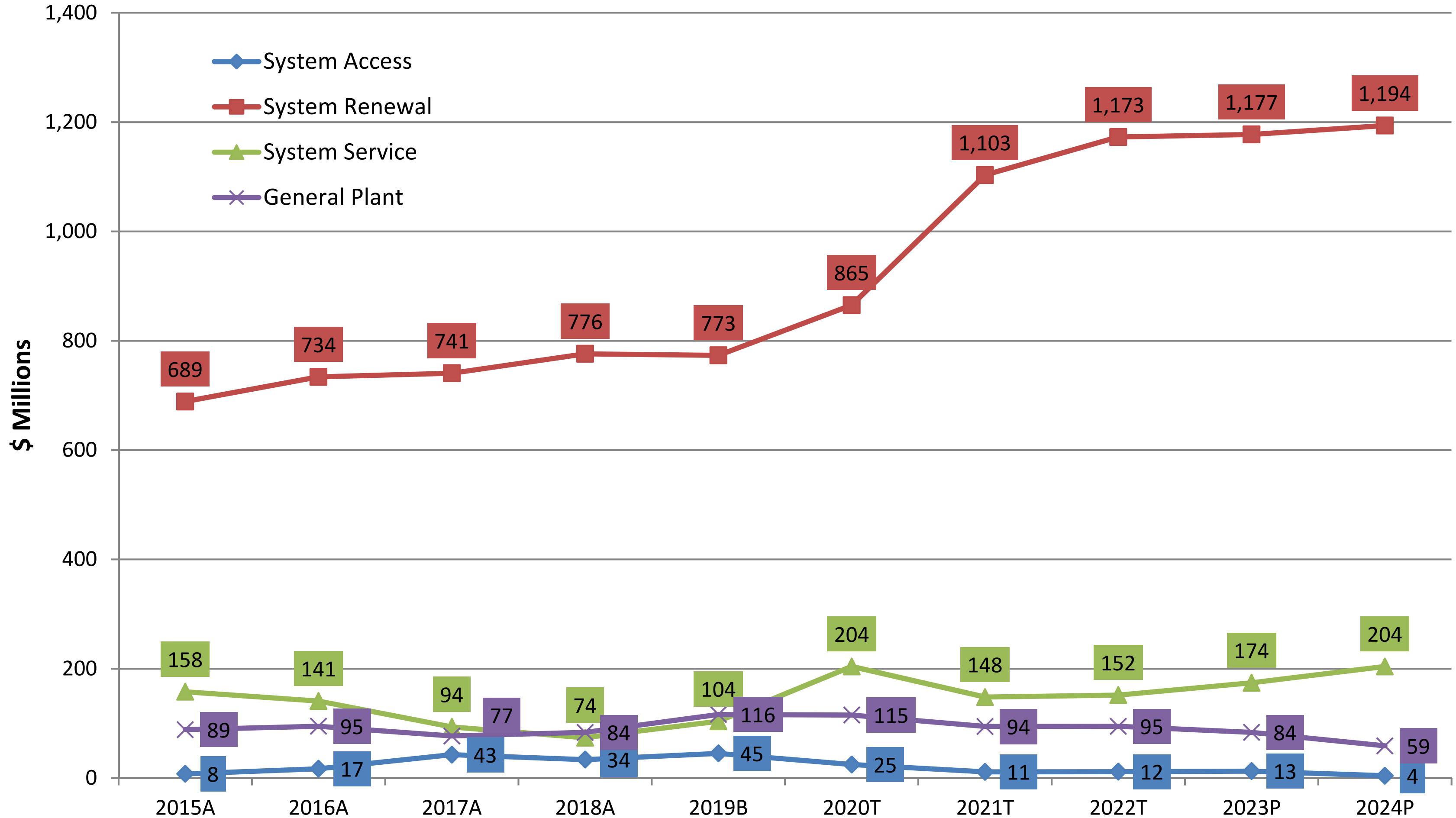

Figure 1 - Actual / Forecast Capital Expenditures 2015 - 2024 by Category

(A=Actual, B=Bridge Forecast, T=Test Forecast, P=Plan)

Hydro One seeks to achieve the following key outcomes through the capital expenditure plan set out in this TSP:

- improved five-year average of delivery point performance, power quality improvements, and increased customer satisfaction with outage coordination through integrated investment planning (Customer Focus);
- an injury-free workplace, lower long-term costs to maintain transmission system infrastructure, and restoring top quartile reliability by mitigating risk arising from asset deterioration and targeting improvements in reliability metrics (i.e., T-SAIDI/SAIFI, System Unavailability) (Operational Effectiveness);
- continued compliance with regulatory requirements, including applicable environmental statutes and regulations, reliability standards, Regional Infrastructure Planning deliverables, and policies regarding the connection of renewable generation (Public Policy Responsiveness); and
- manageable and stable rate impacts over the course of the planning period by undertaking investments to optimize asset value and mitigate future capital investment (Financial Performance).

Hydro One is sensitive to the impacts of the investment plan on its customers. Section 3.2 of the TSP discusses, among other things, how the capital expenditure plan was impacted by and is responsive to customer needs and preferences. Hydro One's approach to investment and targeted outcomes is aligned with the principles in the RRF:

- the TSP reflects customer needs and preferences;
- the company has identified opportunities to extend the useful life of assets and mitigate future higher capital spending requirements for asset replacements;
- the company is actively driving cost reduction and improved productivity and efficiency to offset rate impacts of the proposed investment plan;
- the company has worked with the IESO, transmitters, distributors and other key stakeholders to ensure regional infrastructure needs are addressed in an integrated manner; and

- the company implemented an improved performance management system to provide greater accountability for delivering outcomes to Hydro One's customers.

Hydro One's capital expenditure plan was developed using Hydro One's ongoing process of assessing the condition of critical assets and enhanced investment planning process, which are both detailed in Section 2.1 of the TSP. The proposed capital expenditure plan (including associated outcomes) for each investment category of System Renewal, System Access, System Service, and General Plant is detailed in the following sections.

3.1.1 SYSTEM RENEWAL

System Renewal investments cover the refurbishment or replacement of stations and lines facilities, accounting for about $5.5 billion, or 83% of the net capital expenditures over the five-year TSP period. These investments are required to address assets and systems at the end of their service life (as described in TSP Section 2.2) due to failure, failure risk, substandard performance, high performance risk or functional obsolescence. They allow Hydro One to ensure safety, mitigate reliability risk and maintain compliance with regulatory, environmental and reliability standards. Where feasible, asset life is extended through maintenance programs in order to avoid larger capital replacement costs.

A key finding of Hydro One's asset condition assessment was that a significant portion of transmission system assets have deteriorated to the point where they pose material risks to business objectives for safety, reliability, minimizing environmental impacts and meeting customer needs. This is illustrated in Figure 2 below for major stations and lines assets that are expected to reach the end of their expected service life ("ESL") over the next five years. The significant increase in end-of-life assets is largely due to the historical timing of system expansion and build-up of assets following World War II that are now due for renewal.

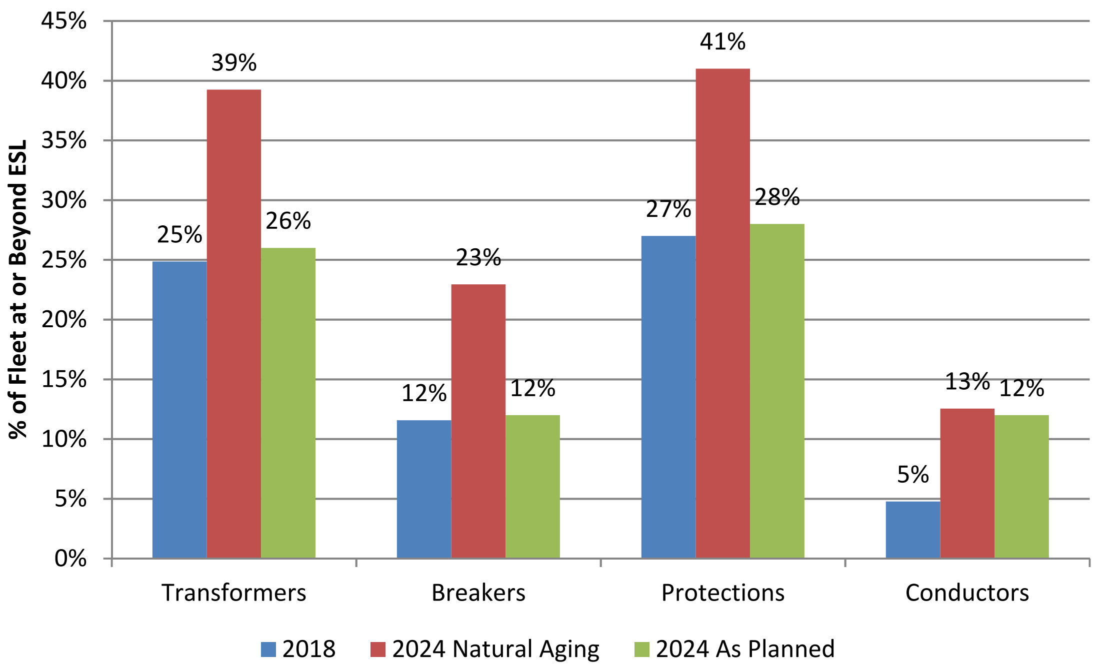

Figure 2 - Assets Operating at or Beyond Expected Service Life

Without the proposed renewal investment, the following percentages of major stations and lines assets are expected to reach the end of ESL by 2024: 41% of protections assets, 39% of transformers, 23% of breakers, and 13% of lines (conductors) assets.

The material System Renewal investments for the TSP period are listed in Table 2 below and are primarily driven by asset condition and performance considerations. Further details on the individual investments are provided in the attachments to Section 3.3.

Table 2 - Major System Renewal Investments

ISD	Investment Title
	Transmission Stations
SR-01	Air Blast Circuit Breaker Replacement Projects
SR-02	Station Reinvestment Projects
SR-03	Bulk Station Transformer Replacement Projects
SR-04	Bulk Station Switchgear and Ancillary Equipment Replacement Projects

SR-05	Load Station Transformer Replacement Projects
SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects
SR-07	Protection and Automation Replacement Project
SR-08	John Transformer Station Reinvestment
SR-09	Transmission Station Demand and Spares and Targeted Assets
SR-10	Transformer Protection Replacement
SR-11	Legacy SONET System Replacement
SR-12	Telecom Performance Improvements
SR-13	ADSS Fibre Optic Cable Replacements
SR-14	Mobile Radio System Replacement
SR-15	Telecom Fibre IRU Agreement Renewals
SR-28	OPGW Infrastructure Projects
Transmission Lines and Cables	
SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures
SR-20	Transmission Line Refurbishment - ACSR Conductor Near End of Life
SR-21	Wood Pole Structure Replacements
SR-22	Steel Structure Coating Program
SR-23	Tower Foundation Assess/Clean/Coat Program
SR-24	Transmission Line Shieldwire Replacement
SR-25	Transmission Line Insulator Replacement
SR-26	Transmission Line Emergency Restoration
SR-27	C5E/C7E Underground Cable Replacement
Cyber Security	
SR-16	NERC CIP-014 Physical Security Implementation
SR-17	NERC CIP Transient Cyber Asset Project
SR-18	PSIT Cyber Equipment Replacement
SR-29	Physical Security ISL Application Replacement

The $5.5 billion in total System Renewal investments include (i) $3.5 billion for stations, which are required to refurbish or replace existing assets located within transmission stations; and (ii) $2.0 billion for lines, which are required to refurbish or replace existing assets associated with overhead and underground transmission lines. The forecast of System Renewal expenditures was determined through the investment planning process (see TSP Section 2.1), based on system needs and condition assessments (see TSP Section 2.2), and with regard to asset life cycle optimization policies (TSP Section 2.3). For the TSP period, individual projects have been bundled into integrated, larger scale station or line projects in order to address all asset needs at a specific site or circuit within a single investment. This integrated approach enables efficient project delivery by optimizing project planning and execution, which minimizes outage requirements and customer impacts.

System Renewal investments aim to address the following stations and lines impacts:

- Prevent a reduction to station reliability as a result of increased asset failures or malfunctions, which could cascade into wider-spread system outages;
- Prevent non-compliance with applicable statutes and regulations, including in relation to equipment oil and noise levels, as well as PCB content restrictions;
- Prevent non-compliance with Northeast Power Coordinating Council's ("NPCC") and North American Electricity Reliability Corporation's ("NERC") reliability standards for protection and control systems;
- Prevent power outages along lines assets due to conductor, structural, insulator and other component failures; and
- Reduce risks to public safety by remediating or replacing poor condition assets situated in and near public areas.

System Renewal investments for stations and lines assets are separately discussed below.

3.1.1.1 Stations Renewal

The TSP includes stations renewal investments of $3.5 billion (53% of the total planning period forecast) to address transformers, circuit breakers, and protection, control and telecom equipment that are deteriorated as determined by condition assessments. Replacement is paced to maintain (though not lower) the proportion of assets beyond ESL over the planning period. Without the proposed investment, the proportion of assets beyond ESL will increase significantly, as set out in Figure 2. As also shown in Figure 2, assuming the planned level of renewal is carried out over the TSP period:

- the population of transformers beyond ESL will increase slightly from 25% to 26% (instead of deteriorating to 39% without the investment),
- the population of breakers beyond ESL will remain steady at 12% (instead of deteriorating to 23% without the investment), and
- the population of protections assets beyond ESL will increase slightly from 27% to 28% (instead of deteriorating to 41% without the investment).

Key stations renewal investments for the TSP period include:

- Replacement of 108 (15%) high risk and deteriorated condition transformers at 44 transmission stations, while eliminating 17 (2%) non-standard or redundant transformers;
- Replacement of 95 (72%) obsolete and poor performing air-blast circuit breakers ("ABCBs") and associated high-pressure air systems located at 8 bulk transmission stations that are key for the reliable operation of the transmission system;
- Replacement of 2,403 (20%) obsolete, non-standard and poor performing protection devices at 72 transmission stations;
- Implementation of cyber security and physical security measures pursuant to regulatory requirements at 26 stations and one control centre; and
- Meeting environmental compliance requirements including the elimination of assets containing PCBs.

Investment in load supply, or customer connected stations is the largest investment in the System Renewal category with $1.6 billion over the five-year plan, which is driven by asset condition and prioritized based on safety, reliability, and environmental impact (see ISD SR-02, SR-05, SR-06, SR-07, and SR-08). Together, the completion of these investments will result in the replacement of 79 transformers, 405 breakers, and 1,341 protection systems over 2020-2024. Additionally, 11 non-standard or redundant transformers and 21 breakers will be eliminated from the system as a result of station reconfiguration to enhance operational effectiveness and meet customer needs and preferences.

Investment in bulk transmission stations will total $578 million over the five-year plan. Similar to load supply stations, bulk station investments are driven by asset condition and prioritized based on safety, reliability and environmental impact. They focus on broader transmission network reliability issues and will be executed in an integrated manner (e.g., see ISD SR-03 and SR-04). These investments will result in the replacement of 19 transformers, 37 breakers, and 290 protection systems over the five-year plan.

Hydro One will invest $158 million over the five-year plan in transformer protections, telecommunication infrastructure and fibre-optic infrastructure to maintain current levels of system reliability (see ISD SR-10, SR-11, SR-12, SR-13, and SR-15). Further, to support field personnel, $19 million will be invested to refresh the provincial mobile radio system (ISD SR-14).

With respect to physical and cyber security infrastructure, Hydro One will invest $82 million over the five-year plan (see ISD SR-16, SR-17 and SR-18) to ensure regulatory compliance and the physical and electronic security of critical system assets.

Lastly, Hydro One will invest $194 million over the five-year plan to purchase spare transformers, support the emergency replacement of failed transformers and other station equipment (see ISD SR-09).

In developing the TSP, Hydro One planned the pace of renewal work so that certain critical work could be completed in the next five years to ensure that transmission assets remain in service and are not subject to increased outage constraints (i.e., resulting from increased failures or additional maintenance requirements) that would make the work more difficult to complete. Hydro One considered both its own ability to execute capital work efficiently and the ability to secure planned outage time to minimize impacts on customers and other stakeholders in Ontario.

Renewal drivers relating to transformers, breakers and protection equipment are more specifically explained below.

3.1.1.1.1 Transformers

Transformers are critical components used in electric power systems to convert power from one voltage level to another to facilitate supply to local distribution companies and industrial customers. Transformer forced outages have been a major cause of customer delivery point interruptions over the past 10 years, representing 13% of equipment-caused events on Hydro One's transmission system. Through asset condition assessment, 17% of Hydro One's transformer fleet are rated high or very high risk based on oil testing results. Currently, 25% of Hydro One's transformer population is beyond its ESL. Assuming no replacements are undertaken, Hydro One anticipates that 280 units (39% of the transformer population) will exceed their ESL by 2024, and 332 units (46% of the population) will exceed their ESL by 2029.

Hydro One plans to manage this risk by replacing an average of 22 transformers annually from 2020 to 2024 selected based on condition. With this replacement rate, Hydro One would be able to maintain the number of units that are beyond ESL to approximately the same level as of 2018, through to the end of 2029.

3.1.1.1.2 Circuit Breakers

A circuit breaker is a mechanical switching device that is capable of carrying and interrupting electrical current under normal and abnormal conditions. During abnormal conditions, breakers operate rapidly to interrupt high currents and minimize impact on the rest of the power system. Hydro One's circuit breaker fleet includes 549 units that are currently beyond their ESL. Breakers have been a significant contributor to customer delivery point interruptions over the past 10 years, representing 13% of these equipment-caused events. Projections for the number of breakers operating beyond ESL by 2024 and 2029, in the absence of replacements or failures, are 1,088 and 1,766, respectively. Condition assessment of the current breaker fleet shows that 9% are rated at a high or very high risk. Furthermore, the entire population of high voltage ABCBs (133 in total) is rated at a high or very high risk when considering factors such as condition diagnostics, performance, criticality, obsolescence and economics.

The frequency and duration of forced outages due to circuit breakers have increased over the past ten years. The frequency increase is primarily attributed to the number of forced outages involving ABCBs, which are the poorest performing breakers in the fleet (see TSP Section 2.2) and are located in critical stations. ABCBs are about ten times more expensive to maintain and four times less reliable compared to SF6 circuit breakers. In addition, approximately 2% of the Hydro One fleet of breakers is no longer supported by vendors, and aftermarket parts are no longer available or are costly to acquire or fabricate. In response to these risks, Hydro One will invest $594 million over the five-year TSP period to replace 95 ABCBs and remove their associated high-pressure air systems (see ISD-SR-01).

3.1.1.1.3 Protection Systems

Protection systems are a critical element of the transmission system. They detect abnormal system conditions and immediately trigger the operation of relevant station equipment (e.g., breakers) to isolate faulted components. Hydro One currently has 12,506 protection systems in-service, approximately 27% of which are operating beyond their ESL. These assets have been a significant contributor to customer delivery point interruptions over the past 10 years, representing 17% of equipment-caused events. Furthermore, over 90% of Hydro One’s solid-state protection fleet is already operating beyond ESL.

Hydro One's replacement strategy for protection systems focuses on assets that have a high likelihood of causing delivery point interruptions and impacting the bulk electric system. Due to the challenges associated with monitoring the condition of all protection systems, other factors like ESL are used to identify high risk assets, which then undergo further condition assessment to identify replacement candidates. Hydro One will replace an average of 480 protection systems per year in the 2020-2024 period, which will largely maintain the current proportion of assets beyond ESL over the planning period (from 27% as of 2018 to 28% by 2024).

3.1.1.2 Lines Renewal

The TSP includes an increased emphasis on lines renewal investments at a cost of $2.0 billion (30% of the total planning period forecast) to refurbish and replace end of life transmission lines, insulators, and wood poles and to continue the steel tower coating program (albeit at a slower pace consistent with the OEB's direction in EB-2016-0160).

Given that a significant portion of Hydro One's transmission lines were built in the 1950s, they will reach the end of their ESL of 90 years in the next two decades. Detailed condition assessments are being conducted for lines exceeding 50 years of age to inform line refurbishment program development. The planned circuit-kilometres of conductor to be replaced in the TSP have been confirmed to be at end of life through condition assessment. While the planned rate of refurbishment does not keep up with the aging lines demographics, risk is being managed by prioritizing line refurbishment investments based on detailed asset condition assessments, which account for the fact that the deterioration rate of transmission line assets depends on location, environmental and system conditions.

Key lines renewal investments for the TSP period include:

- Replacement of 2,127 circuit-km (7%) of end-of-life conductors;

- Replacement of defective insulators on 10,850 (8.5%) primarily critical circuit structures;
- Replacement of 4,000 (9.5%) end-of-life wood poles; and
- Coating of 2,260 (4.3%) steel structures to extend their useful life.

Transmission line sections are comprehensively refurbished when major line components are verified through condition assessment to be deteriorated. Hydro One will invest $425 million to address end of life aluminum core steel-reinforced (“ACSR”) and copper conductor and structures (see ISD SR-19), and $493 million for near end of life ACSR conductor (ISD SR-20). These investments aim to replace a total of 2,127 km, including about 224 km of copper conductor, which is the oldest conductor type in the system and is obsolete since Hydro One can no longer mend certain broken copper conductors. Hydro One will also refurbish steel structures with associated conductors and other lines assets where it has determined that it is economical to replace the entire structure as part of the line refurbishment.

Where Hydro One has determined that complete line refurbishment is not appropriate, it instead pursues overhead line component replacements to address specific asset needs. The wood pole replacement program (see ISD SR-21) is the second largest lines asset investment that will entail $265 million over the five-year plan.

The steel structure coating program, which enables the asset life extension of steel structures, will see $101 million invested over the five-year plan to target 500 structures per year (see ISD SR-22). In addition, Hydro One will invest $104 million from 2020 to 2024 for the refurbishment of steel structure foundations (see ISD SR-23).

Hydro One will invest $64 million over the five-year plan to assess and replace shieldwire that does not meet current design requirements (ISD SR-24). This will address shieldwire that is at risk of mechanical failure (including falling to the ground).

Defective porcelain insulators manufactured by Canadian Ohio Brass ("COB") and Canadian Porcelain ("CP") are identified as high risk and have been targeted for replacement. Hydro One will invest $341 million over the TSP period. In each of 2020 and 2021, it will target 3,700 circuit structures that have defective insulators and that are situated in publicly accessible areas. Beginning in 2022, Hydro One will target 3,450 such circuit structures per year that are not situated in publicly accessible areas (ISD SR-25). This investment is key to preventing insulator failures, which can result in outages and energized conductors falling to the ground (thereby posing significant safety hazards and reliability concerns).

Hydro One will invest $50 million over the five-year plan to support power restoration following transmission line component failures and to replace or repair line components that are likely to fail as identified through line patrols or asset assessment (see ISD SR-26). Given the demand and reactionary nature of this program, the level of investment is in line with historic levels.

Lastly, Hydro One will invest $124 million over the five-year plan to replace 7.2 km of high voltage underground cable due to poor cable performance, condition, and component obsolescence (see ISD SR-27).

Renewal drivers relating to overhead conductors and line insulators are more specifically discussed below.

3.1.1.2.1 Overhead Line Conductors

The conductor of an overhead transmission line transports electricity between system nodes. As such, overhead conductors are the single largest and most vulnerable component of the transmission line system. Lines have been a major contributor to customer delivery point interruptions over the past 10 years, representing 45% of these equipment-caused events. Specifically, given the lack of redundancy, single circuit supplies, which include radial connections, are more likely to result in a customer interruption due to a component failure or weather event. Currently, about 5% of the overhead conductors have reached or exceeded their ESL of 90 years. Without the proposed level of investment, the percentage of conductors exceeding ESL would increase to 13% by 2024.

Hydro One operates a condition assessment program that focuses on conductors beyond 50 years of age. Condition assessment results indicate that 13% of the conductor fleet is at high risk. Despite a planned increased level of replacements when compared to historical levels, the number of conductors beyond the ESL of 90 years is still increasing. An overhead conductor failure can have severe reliability and safety consequences. If this issue is not addressed in a proactive and timely manner, system and customer reliability as well as safety will be placed at risk. Consequently, an increase in planned replacements – even though it will not completely stop or reverse the trend in line demographics – is required to maintain acceptable fleet condition and performance and to avoid a sudden spike in future investments that would otherwise be required as a result of deferred replacements.

3.1.1.2.2 Line Insulators

Line insulators are an integral component of the transmission system. They mechanically support and electrically insulate the conductor from the pole or tower structure, and provide sufficient dielectric strength to prevent short circuits to ground. There are approximately 437,000 insulator strings in Hydro One's overhead transmission network.

As noted above, porcelain insulators manufactured by COB and CP between 1965 and 1982 are known to be defective and susceptible to mechanical and electrical failure. There are approximately 34,000 circuit structures with defective porcelain insulators, including about 15,000 that have been identified as being on structures in critical locations (i.e., near roads, water railways, urban areas, golf courses, educational and health care facilities). Failed insulators typically result in a sustained forced outage because of the resulting permanent electrical fault. Repair time can be prolonged, averaging 36 hours per outage, depending on the location and severity of the failure. To date, Hydro One has replaced approximately 8,900 publically accessible COB and/or CP insulators.

3.1.2 SYSTEM ACCESS

System Access investments are required to provide new load and generation customer connections, and address transmission asset modifications to accommodate third party requests. These investments account for about $345 million of Hydro One's gross capital expenditures for the TSP period. However, the majority of these investments are recoverable from customers in accordance with the Transmission System Code. Therefore, the net capital impact is approximately $65 million or less than 1% of the total net capital expenditures over the five-year plan.

The load and generation connection investments are customer driven, based on requests for connection capacity, as well as reliability needs identified through the regional planning process (as described in Section 1.2) or in connection with IESO generation contracts. Transmission asset modification investments are driven by third party requests to facilitate or permit secondary land use. The magnitude and volume of work in this investment category can vary significantly year over year based on customer requirements. The material System Access investments within the five-year plan are shown in Table 3 below. A complete listing and further details regarding individual material investments are provided in Section 3.3.

Table 3 - System Access Material Investments

ISD	Investment Title
SA-01	Connect New IAMGOLD Mine
SA-02	Horner TS: Build a Second 230/27.6 kV Station *
SA-03	Halton TS: Build a Second 230/27.6kV Station*
SA-04	Connect Metrolinx Traction Substations
SA-05	Future Transmission Load Connection Plans
SA-06	Protection and Control Modifications for Distributed Generation
SA-07	Secondary Land Use Transmission Asset Modification Projects – Recoverable from Customers

(*) Represents investment that was identified in the Regional Planning Process

All of the System Access investments forecast over the planning period are based on investment needs identified through a specific load or generator customer and/or third party request as mentioned above. These investments are non-discretionary, since Hydro One is required to provide transmission access when requested pursuant to the terms of its Transmitter License and the Transmission System Code.

Hydro One plans to undertake approximately $206 million of work to connect load customers over the planning period. A significant portion of this work is recoverable from customers; therefore, the net capital impact of this work is about $58 million over the planning period. This investment in load customer connection work is required to: build new or expand existing transformer stations to increase capacity and meet load growth (see ISD SA-02 and SA-03), and provide connection to customer owned stations (see ISD SA-01) including the connection to six traction power stations for the Metrolinx rail electrification project (see ISD SA-04).

Hydro One also plans to undertake approximately $35 million of work related to generation customer connections over the TSP period. The majority of the projects in this category are below the materiality threshold and associated costs are recoverable from relevant customers. The net capital impact of this work is less than $2 million over the planning period. Generator customer connection work is required to: connect generation customers at the transmission level and execute transmission system upgrades to enable such connections (see ISD SA-06).

Lastly, Hydro One plans to undertake approximately $103 million of work related to secondary land use transmission asset modifications over the TSP period. The size and complexity of these projects vary from year to year; the costs of majority of the projects in this category are recoverable from third parties. The net capital impact of this work is approximately $4 million over the planning period which covers the re-establishment of property rights and corridor safety enhancements. These investments include the relocation, removal, or reinforcement of transmission assets to facilitate third-party projects (e.g., roadwork, transit systems, and other major infrastructure or development work) that may encroach upon or impact Hydro One assets and rights-of-ways (see ISD SA-07).

3.1.3 SYSTEM SERVICE

System Service investments are required to: maintain inter-area network transfer capability, ensure local area supply adequacy, mitigate system risks related to safety, security and reliability, and address customer power quality concerns. These investments account for about $955 million of gross capital expenditures over the five-year plan. However, some of these investments are recoverable from customers in accordance with the Transmission System Code. The net capital impact is approximately $883 million or about 13% of the total net capital expenditures over the 2020-2024 period.

These investments are non-discretionary with the majority having been identified as a result of regional planning processes, IESO bulk planning studies, or the 2017 Long-Term Energy Plan.

The material System Service investments outlined in this TSP are listed in Table 4. A complete listing and further details on individual material investments are provided in Section 3.3.

Table 4 - System Service Material Investments

ISD	Investment Title
SS-01	Lennox TS: Install 500kV Shunt Reactors
SS-02	Wataynikaneyap Line to Pickle Lake Connection **
SS-03	Nanticoke TS: Connect HVDC Lake Erie Circuits**
SS-04	East-West Tie Connection**
SS-05	St. Lawrence: Phase Shifter Upgrade
SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade**
SS-07	Milton SS: Station Expansion and Connect 230kV Circuits**
SS-08	Northwest Bulk Transmission Line**
SS-09	Barrie Area Transmission Upgrade*
SS-10	Kapuskasing Area Transmission Reinforcement
SS-11	South Nepean Transmission Reinforcement*
SS-12	Aylmer-Tillsonburg Area Transmission Reinforcement*
SS-13	Leamington Area Transmission Reinforcement*
SS-14	Southwest GTA Transmission Reinforcement*

(*)Represents investment that was identified in the Regional Planning Process
(**) Represents investment identified in the 2017 Long-Term Energy Plan

Hydro One plans to invest approximately $481 million on inter-area capacity investments; with a net capital impact of $446 million over the planning period. These investments will provide: new or upgraded transmission facilities to increase the transfer capability between generation areas and load centres within Ontario and with neighbouring utilities (see ISD SS-02 to SS-04, and, SS-06 to SS-08), and provide bulk system reactive control (see ISD SS-01 and SS-05).

Hydro One also plans to invest about $435 million in local area supply; with a net capital impact of $398 million over the planning period. These investments will provide new or upgraded facilities to ensure area supply adequacy, and meet load forecast requirements in areas where existing transmission facility loading levels reach or exceed capacity (see ISD SS-09 to SS-15).

Lastly, Hydro One plans to invest approximately $39 million in risk mitigation, reliability performance enhancement, and addressing customer power quality issues. The majority of the projects in this category are below the material threshold except for customer power quality (see ISD SS-16). These investments will ensure compliance with mandatory standards and demonstrate Hydro One's responsiveness to customer concerns.

3.1.4 GENERAL PLANT

General Plant assets are not part of the electricity transmission system but are nonetheless required to support the safe, efficient and effective performance of the utility's core business and operational functions. The TSP includes $447 million in General Plant investments (7% of net capital expenditures over the five-year plan), which are required to support business and operations activities relating to buildings, tools, equipment, rolling stock, and information technology hardware and software.

General Plant investments tend to be relatively smaller in size and are grouped as shown in Table 5. Further details are provided in Section 3.3 of this TSP.

Table 5 - General Plant Categories

ISD	Investment Category
GP-01	Integrated System Operations Centre - New Facility Development
GP-02	Grid Control Network Sustainment
GP-03	Network Management System Capital Sustainment
GP-04	Integrated Voice Communications and Telephony System Refresh
GP-05	Transmission Non-Operational Data Management System
GP-06	Operating Common IT Infrastructure
GP-07	Hardware/Software Refresh and Maintenance
GP-08	Corporate Services Transformation - HR / Payroll
GP-09	Corporate Services Transformation - Finance
GP-10	Facility Accommodation & Improvements Service Centres & Admin
GP-11	Transmission Facilities & Site Improvements
GP-12	Transport & Work Equipment

Major investments in the General Plant category are highlighted below.

<u>Operating Infrastructure and Control Facilities</u>

Hydro One proposes to invest $189 million in operating infrastructure and control facilities. This includes an investment of $45 million[5] over 2020-2021 to build the new Integrated System Operating Centre (“ISOC”) to ensure the continued safe and reliable operations of the transmission system (see ISD GP-01). The ISOC will provide a reliable primary operation and telecommunication management centre as well as a security operation centre which will ensure compliance with NERC reliability standards.

Hydro One will also invest $23 million in the development of a non-operational data management system (see ISD GP-05) to establish the necessary framework to enable automation and modernization of the transmission system, leading to more effective and better informed decision making as well as enhanced post-fault analysis. In addition, $34 million is allocated for the replacement of end of service life elements of the grid control

[5] The ISOC will be used by both Hydro One Transmission and Hydro One Distribution. $45 million is allocated to Hydro One Transmission. See ISD GP-18 of Exhibit B1-1-1 in Hydro One Distribution’s 2018-2022 application (EB-2017-0049) for the amount allocated to Hydro One Distribution. Details on Common Asset Allocation are described in Exhibit C, Tab 3, Schedule 1.

network (see ISD GP-02) to maintain system operability. The Network Management System ("NMS") will be upgraded between 2021 and 2023 at a projected cost of $38 million, which will maintain the reliable operation of the bulk electric system (see ISD GP-03). The Integrated Voice Communications and Telephony System ("IVCT") will be refreshed to enable the efficient management of daily call volumes and communication between the Ontario Grid Control Centre, Backup Control Centre and IESO as per regulatory requirements at a planned cost of $6 million[6] over the planning period (see ISD GP-04).

Transport, Work and Service ("TWE") Equipment

The TSP includes $76 million for TWE equipment including $66 million for fleet and $10 million for service equipment.

Hydro One will invest $66 million[7] between 2020 and 2024 to keep its 7,000 fleet vehicle units operating safely and to support its work programs (see ISD GP-12). Vehicles at end of life will be replaced to minimize day-to-day maintenance and operational costs, maximize productivity (i.e, minimizing downtime), protect public and employee safety, and meet compliance obligations (e.g., under the *Highway Traffic Act*).

Information Technology ("IT")

The General Plant category includes an investment of $91 million on IT assets, including:

- $14 million[8] in hardware and software refresh and maintenance programs (see ISD GP-07) to ensure the continued operation of the IT application infrastructure and upgrade existing systems;

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[6] Amount allocated to Hydro One Transmission. Refer to EB-2017-0049, ISD GP-23 for Distribution allocation.
[7] Amount allocated to Hydro One Transmission. Refer to EB-2017-0049, ISD GP-01 for allocation to Distribution.
[8] Amount allocated to Hydro One Transmission. Refer to EB-2017-0049, ISD GP-05 for allocation to Distribution.

- $12 million[9] in critical IT infrastructure (see ISD GP-06) to address equipment needs generated by the growth in demand for IT services, capacity limitations and the replacement of end-of-life equipment;
- $21 million[10] in planned financial and work management system transformation (see ISD GP-09) and $7 million[11] in planned human resources ("HR") and payroll transformation (see ISD GP-08) aimed at optimizing talent management, time and payroll management and HR performance; and
- other smaller investments below the $3 million materiality threshold, such as refreshing enterprise analytics, GIS modernization, enterprise content and document management and reporting systems, IT security programs to ensure ongoing sustainment of newly commissioned security tools, policies, practices, standards and regulatory requirements.

Facilities

Hydro One will invest $90 million in facility accommodation and transmission site facility capital repairs and improvements (ISD GP-10[12], ISD GP-11). This includes additions to and renovation of existing facilities and the acquisition of new facilities to address existing and/or new accommodation requirements; replacement of major building system/components, including roof structures; windows and cladding; HVAC systems, electrical, lighting and control systems, and other fundamental structural elements; and site-related replacements and additions, including drainage, asphalt, and fencing.

Material General Plant investments are described in detail in Section 3.3.

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[9] Amount allocated to Hydro One Transmission. Refer to EB-2017-0049, ISD GP-19 for allocation to Distribution.
[10] Amount allocated to Hydro One Transmission. Refer to EB-2017-0049, ISD GP-17 for allocation to Distribution.
[11] Amount allocated to Hydro One Transmission. Refer to EB-2017-0049, ISD GP-13 for allocation to Distribution.
[12] This ISD represents the Transmission allocation. See EB-2017-0049, ISD GP-02 for Distribution allocation.

3.2 CAPITAL PLANNING DRIVERS AND CONSIDERATIONS

Section 3.1 provided a summary of Hydro One's capital expenditure plan for the four major investment categories (System Renewal, System Access, System Service, and General Plant). While that section outlined the capital expenditure plan largely from the lens of system and asset needs as well as certain key investment drivers (i.e., reliability, safety, customer requirements and compliance obligations), it is important to recognize the role and significance of a myriad of other drivers and considerations that shaped, informed, and impacted the development of this TSP, in accordance with the principles and requirements of OEB's Renewed Regulatory Framework ("RRF"). Section 3.2 discusses these other drivers and considerations and their impact on Hydro One's TSP, including:

- Customer needs and preferences as identified through customer engagement;
- Customer connection and regulatory and public policy requirements (i.e., regional planning processes, and the Long Term Energy Plan ("LTEP"));
- Benchmarking analyses;
- Performance measurement;
- Productivity Savings; and
- Timing and pacing that appropriately account for customer rate impacts and execution considerations.

3.2.1 (5.4 B, 5.4.1 A, 5.2.1 B)HOW THE PLAN REFLECTS CUSTOMER ENGAGEMENT

Hydro One's objective is to engage with customers consistently and proactively. The company's full spectrum of customer engagement initiatives, as described in TSP Section 1.3, is designed to: (i) increase the company's understanding of customer needs and preferences; (ii) enhance Hydro One's ability to provide services that meet these needs; (iii) achieve outcomes that are valued by customers; and (iv) attain an improvement in overall customer satisfaction with service received from Hydro One.

In May 2017, Hydro One engaged with its customers through a formal Customer Engagement Survey to learn about the outcomes that customers care about, as well as the level of spending and mix of investments that customers would like to see included in the plan. Through this engagement, customers rated seven outcomes on a scale of importance. Based on the information collected during this engagement process (as described in TSP Section 1.3), the following customer needs and preferences were identified:

- Customer priorities are as follows: safety, reliability and outage restoration, followed by power quality, customer service, productivity and environmental stewardship.
- All business customer segments, particularly LDCs, prefer that investments be spread out over time, along with stable rate increases. This preference is due primarily to perceived affordability for ratepayers and the ability to plan ahead.
- Reducing the frequency of power interruptions is more important than reducing the duration. Most important is reducing the number of day-to-day interruptions.

Hydro One's TSP is customer focused and designed to meet customer needs and preferences and result in outcomes that customers value. This plan reflects the results of the customer engagement process while balancing system/asset needs, risk mitigation and cost by:

- Optimizing the life of existing assets while mitigating the risk to safety and to current service levels posed by asset deterioration;
- Improving system and customer reliability;
- Addressing customer needs and preferences through new customer connections, and regional development to enable growth and system renewal to meet current requirements;
- Coordinating system renewal investments and maintenance with generator customers during planned outages to minimize disruption to operations;
- Responding to customer power quality concerns by proactively monitoring power quality across the province and working with customers to resolve specific issues; and
- Incorporating increased cost reductions, efficiency and productivity improvements to offset the customer rate impacts of the proposed investment plan.

In addition to its Customer Engagement Survey, Hydro One has several ongoing activities that it uses to engage with its customers. These are described below.

3.2.1.1 Oversight Committees and Working Groups

In addition to formal customer engagement research, Hydro One has established a number of specific oversight committees and working groups with its customers, as described in TSP Section 1.3. These committees and working groups provide avenues for feedback for customers in areas where there has been a high level of customer interest, where careful and ongoing coordination with other entities is particularly valuable, and/or where there is a need for coordinated health and safety oversight.

3.2.1.1.1 Sarnia Area Reliability Oversight Committee

In light of the sensitivity of industrial and generation-connected customers to voltage and power quality issues in the Sarnia area, the Sarnia Area Reliability Oversight Committee meets to identify reliability issues in the Sarnia area and review proposed annual work plans and investments. This forum enables collaborative discussion on proposed work programs that would affect customers in the area, including discussion on proposed investment at *Sarnia Scott TS* (ISD SR-03) and *St. Andrews TS* (ISD SR-02) to ensure the switchyard reliability and configuration meet customer needs. A recent investment at Wanstead TS, completed in 2018, has resulted in the station being supplied from the 230 kV network instead of the previous 115 kV connection point in light of concerns expressed over reliability of the current supply to Wanstead TS.

3.2.1.1.2 LDC Working Group and Toronto-Hydro Oversight Committee

With several investments planned for the Toronto Hydro-Electric System Ltd. ("THESL") service area, including station reinvestment at Runnymede TS, and Fairbank TS (ISD SR-02) and John TS (ISD SR-08), transformer replacements at Bathurst TS, Bridgman TS, Charles TS, Duplex TS, Fairchild TS, Main TS, and Strachan TS (ISD SR-05), and switchgear replacement at Finch TS, Leaside TS, and Rexdale TS, and additional capacity at Horner TS (ISD SA-02), the oversight committee provides a venue to consult and collaborate with THESL to ensure customer needs and preferences inform planning and investment decisions. This includes incorporating feedback on switchyard configuration, equipment ratings, feeder egress, and outage coordination.

3.2.1.1.3 Switchyard Oversight Committees

Significant investment is planned for the replacement of air blast circuit breakers ("ABCBs") at major Hydro One facilities connected to Bruce Power and Ontario Power Generation nuclear generation facilities. To this end, coordination and collaboration are paramount to the successful execution of these projects. These committees ensure that specific generator requirements (e.g., equipment ratings and synchronizing capability) are captured within the proposed investment plan. The ABCB replacement projects at Bruce A TS, Bruce B TS, and Cherrywood TS are detailed in ISD SR-01.

3.2.1.1.4 Metrolinx Working Group

This working group provides a forum for considering issues in a coordinated manner in connection with the large scale and broad scope of transportation infrastructure work that Metrolinx is undertaking in Ontario. Through this forum, the working group reviews and addresses, in an efficient and coordinated manner, customer escalations arising from the Metrolinx work program work. This includes the ongoing work to connect the Metrolinx Traction Substations (ISD SA-04) as part the GO Transit electrification project.

3.2.1.1.5 Hydro Ottawa Oversight Committee

This working group provides a forum to identify and resolve any issues and to ensure safe and efficient operations between Hydro One and Hydro Ottawa. Meetings also allow the parties to coordinate efforts relating to capital projects and other matters.

3.2.1.2 Focused Planning Meetings with Customers

Customer engagement is a common theme throughout Hydro One's investment planning process described in TSP Section 2.1. In addition to the above, customer engagement is a key consideration in the development of the investments contained within this TSP. Hydro One's planning staff engages with customers regularly and through a variety of mechanisms, in a manner that is most effective for the relevant customer. This includes regularly scheduled meetings or conference calls (e.g., on a monthly or quarterly basis, or on a per project basis) as asset or system needs are identified during initial planning phases. These ongoing conversations with customers ensure their needs and preferences inform the investment plan, whether for new or existing connections.

System Access investments presented within this TSP reflect customer needs for new load or generation connections and are driven based on customer requests for connection capacity and reliability improvements or needs identified as part of the regional planning process, described in TSP Section 1.2, or in connection with Independent Electricity System Operator ("IESO") generation contracts.

System Service investments presented within this TSP reflect system and customer needs to maintain network transfer capability and system reliability and also address customer power quality concerns. These needs are identified through direct customer engagement or through the Regional Planning processes discussed in TSP Section 1.2. Investments to maintain network transfer capability, system reliability and power quality concerns are included as part of this TSP.

System Renewal investments presented within this TSP incorporate customer needs and preferences as established through the Asset Risk Assessment (“ARA”) process detailed in TSP Section 2.1.2.3. Planners engage connected customers during the preparation of the scope of work to solicit input and feedback on the proposed plans to ensure needs and preferences are addressed in a collaborative manner.

These continuous communications and engagement activities enable Hydro One to ensure customer needs and preferences inform investment planning decisions and strengthen customer relationships on an ongoing basis.

3.2.1.3 Investment Planning Informed by Customer Engagement

As described in TSP Section 2.1, as part of Hydro One’s investment planning process, Hydro One planning functions assess the risks of not proceeding with investments based on the applicable investment prioritization and optimization framework. This framework reflects Hydro One’s priorities, the principles of the RRF and outcomes valued by customers, which have been identified through customer engagement processes. This alignment ensures Hydro One’s investment planning decisions are positioned to deliver outcomes that are valued by customers.

In addition to a broad alignment of investment planning decisions criteria with customer values, Hydro One identifies and tracks other, more qualitative customer needs and preferences that are incorporated into its investment plans, such as outage/asset renewal coordination, proactive communication, power quality, and performance improvements, as captured through the customer engagement flag.

As discussed in Section 1.3, throughout the planning process, the ongoing alignment of investment drivers with identified needs and preferences was monitored. From the candidate investment development stage through to TSP finalization, the funding status of customer flagged investments was monitored, discussed and considered.

A number of investments were identified and proposed over the five-year planning horizon to respond to specific customer needs and preferences. Examples of these investments are highlighted by theme in Table 1 below; further details on material capital investments are provided in Section 3.3 and discussion on OM&A programs is provided in Exhibit F.

Table 1 – Investments Informed by Customer Feedback

ISD	Description	Customer Engagement Considerations
Customer Coordination of Asset Renewal		
SR-02	Carlton TS	Customer (Alectra) was consulted on final station configuration to meet customer needs
SR-02	Gage TS	Reconfiguration of switchyard based on customer needs and decreased industrial loading
SR-02	Glendale TS	Customer (Alectra) was consulted on final station configuration to meet customer needs
SR-02	Kenilworth TS	Customer (Alectra) was consulted on final station configuration to meet customer needs
SR-05	Strachan TS	Request for larger capacity transformer by Toronto Hydro.
N/A[1]	St. Thomas TS	Coordination with Aylmer Tillsonburg Area Transmission Reinforcement Project (SS-14) to address voltage drop and customer reliability.
SR-07	Frontenac TS	Coordination with Utilities Kingston to address asset needs and feeder protections

[1] Investment is below $3 million materiality threshold.

ISD	Description	Customer Engagement Considerations
Customer Coordination/Communication		
N/A[2]	ROW Notification Program	The notification program is required to inform all adjacent property owners of upcoming ROW maintenance. Customers are accustomed to receiving notifications prior to maintenance and without the program, may have strong objections to the vegetation changes. Negative media attention would likely result.
N/A[1]	Tx Portal Enhancement	Enhancement to Transmission Customer Portal
Customer Outage Coordination		
N/A[2]	Circuit Breaker Maintenance and Refurbishment	OPG Darlington has provided their overhaul schedule for their generating units, with the expectation that Hydro One will complete the refurbishment of the breakers within the timing of the unit overhaul, in order to minimize requirements for outages for performing this type of maintenance in the future.
SR-01	Bruce B SS	Replacement of Air Blast Circuit Breakers (ABCBs) will be aligned with Bruce Power refurbishment project.
SR-01	Cherrywood TS	Replacement of Air Blast Circuit Breakers (ABCBs) will be aligned with OPG to coordinate with Pickering GS shutdown plan.
SR-01	Beck 1 SS	Replacement of Air Blast Circuit Breakers (ABCBs) will to be aligned with OPG canal refurbishment project.
SR-01	Bruce A TS	Replacement of Air Blast Circuit Breakers (ABCBs) will be aligned with Bruce Power refurbishment project
SR-03	Sarnia Scott TS	Asset replacements will be coordinated with petroleum sector customers to minimize outages to customer supply points.
Performance Improvement		
N/A[2]	Nuisance Wildlife Control	Numerous customers request animal mitigation performance numbers and updates on investments (i.e. Domtar, Alectra, Toronto Hydro)
N/A[2]	Nuisance Wildlife Control (Civil)	Numerous customers request animal mitigation performance numbers and updates on investments (i.e. Domtar, Alectra, Toronto Hydro)
SR-02	Kent TS	Entegrus Powerlines have expressed issues with delivery point performance due to physically split transitional bus.
SR-19	K1/K2 Refurbishment	Improve reliability performance of circuits supplying outlier delivery points.
SR-20	A4L Refurbishment	Improve reliability performance of circuits supplying outlier delivery points.

[2] See Exhibit F for discussion of OM&A programs.

ISD	Description	Customer Engagement Considerations
N/A[1]	Circuit Switchers for Outlier Improvement	Based on recent customer survey, most consider reliability to be extremely important. This investment is proposed to improve the reliability of some of the worst performing delivery points (outliers)
Power Quality		
N/A[1]	Customer Power Quality (Tx) – OM&A	The planned Customer PQ program expenditure will address the expected demand of customer enrollments in the PQ meter integration initiative program and the expected increase in third party audit activities. Hydro One will continue to monitor the effectiveness of this program and adjust future program funding accordingly.
SS-16	Customer Power Quality (Tx) - Capital	Installation of cap-switchers at transmission stations based on the severity of transient over voltages and the complaints received from industrial customers. For example: the installation of a cap-switcher at Napanee TS to address a complaint received from a large customer supplied from that transmission station.

While the topic of capacity expansions was also raised by select respondents, connection facility investments are typically at least partially customer funded and have generally been excluded from this aspect of the investment planning framework, as they are captured as third-party requests.

3.2.2 (5.4.1 B, 5.4.1 D) HOW THE PLAN REFLECTS REGIONAL PLANNING

Many of the System Access, System Service and System Renewal investments mentioned above in Section 3.2.1 have been identified as a result of Regional Planning processes.

The investments identified through the Regional Planning process account for about $1.8 billion of gross capital expenditures over the five-year plan. However, some of these investment costs are recoverable from customers in accordance with the Transmission System Code. Therefore, the net capital impact is approximately $1.7 billion or about 25% of the total net capital expenditures over the five-year plan.

Detailed information on the Regional Planning process and region by region outcomes, including the list of projects contributed, can be found in Section 1.2. The material TSP investments identified through Regional Planning are listed in Table 2 below. Further details on these individual material investments are provided in Section 3.3.

Table 2 - Material Investments Identified in Regional Planning

ISD	Investment Title
System Access	
SA-02	Horner TS: Build a Second 230/27.6kV Station
SA-03	Halton TS: Build a Second 230/27.6kV Station
System Service	
SS-02	Watay Line to Pickle Lake Connection
SS-07	Milton SS: Station Expansion and Connect 230kV Circuits
SS-09	Barrie Area Transmission Upgrade
SS-11	South Nepean Transmission Reinforcement
SS-12	Aylmer-Tillsonburg Area Transmission Reinforcement
SS-13	Leamington Area Transmission Reinforcement
SS-14	Southwest GTA Transmission Reinforcement
System Renewal	
SR-02	Arnprior TS: Station Reinvestment
SR-02	Elgin TS: Station Reinvestment
SR-02	Fairbank TS: Station Reinvestment
SR-02	Gage TS: Station Reinvestment
SR-02	Kenilworth TS: Station Reinvestment
SR-02	Runnymede TS: Station Reinvestment
SR-02	Sheppard TS: Station Reinvestment
SR-02	Slater TS: Station Reinvestment
SR-02	St. Andrews TS: Station Reinvestment
SR-02	Wonderland TS: Station Reinvestment
SR-03	Beach TS: Transformer Replacement
SR-03	Detweiler TS: Transformer Replacement
SR-03	Keith TS: Transformer Replacement
SR-03	Manby TS: Transformer Replacement
SR-03	Sarnia Scott TS: Transformer Replacement
SR-05	Bermondsey TS: Transformer Replacement
SR-05	Birmingham TS: Transformer Replacement
SR-05	Bridgman TS: Transformer Replacement
SR-05	Cedar TS: Transformer Replacement
SR-05	Charles TS: Transformer Replacement
SR-05	Duplex TS: Transformer Replacement
SR-05	Fairchild TS: Transformer Replacement

ISD	Investment Title
SR-05	Hanlon TS: Transformer Replacement
SR-05	Hawthorne TS: Transformer Replacement
SR-05	King Edward TS T3 and PCT Replacement
SR-05	Kingsville TS: Transformer Replacement
SR-05	Lauzon TS: Transformer Replacement
SR-05	Leslie TS: Transformer Replacement
SR-05	Longueil TS: Transformer Replacement
SR-05	Main TS: Transformer Replacement
SR-05	Minden TS: Transformer Replacement
SR-05	Newton TS: Transformer Replacement
SR-05	Orangeville TS: Transformer Replacement
SR-05	Parry Sound TS: Transformer Replacement
SR-05	Preston TS: Transformer Replacement
SR-05	Strachan TS: Transformer Replacement
SR-05	Woodbridge TS: Transformer Replacement
SR-06	Burlington TS: MV Switchard Refurbishment
SR-06	Dundas TS: MV Switchyard Refurbishment
SR-06	Lake TS: MV Switchyard Refurbishment
SR-06	Norfolk TS: Switchyard Refurbishment
SR-08	John Transformer Station Reinvestment Project
SR-19	B3/B4 | Horning Mountain JCT-Glanford JCT: Line Refurbishment
SR-19	H1L/H3L/H6LC/H8LC | Bloor Street x Leaside: Line Refurbishment
SR-27	C5E/C7E: HV Underground Cable Replacement

3.2.3 (2.4 TRANSMISSION) HOW THE PLAN REFLECTS LTEP

As highlighted in the 2017 LTEP, there will be no need for any further major expansion of the transmission system beyond the projects already planned or under development, based on the demand forecast and the years of investment in Ontario to renew the electricity system.

The planned or under-development transmission investments identified in the LTEP are required to facilitate supply to First Nations, facilitate new or optimize existing interconnection capabilities, prepare for the retirement of the Pickering Nuclear Generating Station, and accommodate long term load growth.

These LTEP investments are reflected under the System Service category (see TSP Section 3.1) and account for $420 million or about 5% of the total capital expenditures over the five-year plan.

The LTEP major transmission investments are listed in Table 3 below. Further details on these individual investments are provided in Section 3.3 of the TSP, with the exception of Clarington Transformer Station which was placed in-service in 2018.

Table 3 - LTEP Major Transmission Projects

ISD	Project Description
SS-02	Wataynikaneyap Power Line to Pickle Lake Connection
SS-03	Nanticoke TS: Connect HVDC Lake Erie Circuits
SS-04	East-West Tie Connection
SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade
SS-07	Milton SS: Station Expansion and Connect 230kV Circuits
SS-08	Northwest Bulk Transmission Line
*	Clarington Transformer Station

(*) This project was completed in 2018. For details on this project, refer to proceeding EB-2016-0160, Exhibit B1, Tab 3, Schedule 11, ISD D01.

In addition to the major transmission projects listed above, the LTEP identifies a number of Regional Planning projects that form part of Hydro One's five-year plan, as previously noted in Section 1.7.

3.2.4 (5.4.1 A, 5.4.1 B) HOW THE PLAN REFLECTS BENCHMARKING

As described in Section 1.4.1.1, Hydro One engaged various third party experts to perform a series of studies on major asset types and their treatment, so as to assess whether Hydro One is following industry best practices in the areas of condition assessments, asset management and capital expenditure pacing. The studies confirm Hydro One's use of industry best practices and affirm the pacing of capital expenditures.

3.2.4.1 Operating Spare Transformers Requirement Assessment

This study found that the results of Hydro One's Markov model analysis (used to determine the appropriate number of spare transformers), aligns with the independent and alternative analysis from the third-party expert, Electric Power Research Institute ("EPRI"). Hydro One continues to take steps to achieve and maintain the required quantity of operating spare transformers to ensure reliability and improve cost efficiency.

3.2.4.2 Derivation of Transformer Hazard Functions

This study confirmed that Hydro One's pacing approach to the replacement of transformers is appropriate. This pacing of transformer replacement has been reflected in the following ISDs: SR-02 (Station Reinvestment Projects), SR-03 (Bulk Station Transformer Replacement Projects), SR-05 (Load Station Transformer Replacement Projects), and SR-08 (John Transformer Station Reinvestment).

3.2.4.3 Derivation of Circuit Breaker Hazard Function

This study was performed by EPRI and describes EPRI's efforts to (i) model and develop circuit breaker removal rates from historical replacement records and (ii) apply them to forecast the number of circuit breakers expected to require replacement based on past practices. EPRI has developed a methodology using advanced statistical techniques for analyzing circuit breaker historical removals and applied it to the Hydro One's circuit breaker fleet. Using Hydro One's circuit breaker retirement data, EPRI modeled Hydro One's circuit breaker removals and has forecast probable future removal rates. The study confirmed that Hydro One is replacing younger circuit breakers at a rate expected from the statistical model. However, older circuit breakers are being replaced at a quicker rate than expected. The reason for faster paced replacement is due to replacement criteria that are not included in the EPRI report as explained below.

Hydro One plans to address 638 breakers over the planning period. This includes the removal of 49 breakers as a result of station decommissioning and reconfiguration as well as the additional installation of 15 breakers resulting from customer requests to increase operational flexibility in the Toronto area. As per the EPRI analysis, there is a 90% probability that Hydro One will need to replace 491 breakers or fewer. However, Hydro One's volume of replacement over the plan period is higher primarily due to obsolescence concerns, safety concerns (e.g. insufficient arc resistance), PCB mitigation, and integrated investments which are not reflected in the EPRI analysis.

The EPRI analysis is derived from asset retirement data from 1981 to 2017. The analysis does not reflect the necessary replacement of 95 ABCBs over the planning period due to worsening reliability, as Hydro One has operated its fleet longer than industry peers. Similarly, the historical mid-life refurbishment of oil breakers from 1950 to 2007 has enabled Hydro One to operate approximately 300 currently in-service breakers for a longer period prior to retirement. Based on how the calculations were performed, this skews the predicted replacement rate. PCB mitigation also contributes to the increased rate of replacement in order to meet federally legislated deadlines. Out of the 247 oil circuit breakers identified for replacement over the planning period, 69 (28%) have measured above the acceptable level of 45 ppm for PCBs. Due to increased obsolescence concerns and the lack of, or reduction of, vendor support with respect to oil, metalclad, and vacuum breakers, the capital plan paces breaker replacements to mitigate reliability impact. Where breakers that are not end of life are removed from service because it is part of an integrated investment (e.g., due to the replacement and relocation of a switchyard), these breakers are placed into spares to support the remaining fleet. Oil circuit breakers can be salvaged for parts to support the remaining fleet, while complete SF6 breakers are placed into the spare equipment pool to support demand replacements.

This pacing of circuit breaker replacement has been reflected in the following ISDs: SR-02 *Station Reinvestment Projects*, SR-04 *Bulk Station Switchgear and Ancillary Equipment Replacement Projects*, SR-06 *Load Station Switchgear and Ancillary Equipment Replacement Projects*, and SR-08 *John Transformer Station Reinvestment*.

3.2.4.4 ESL Survey of Transformers

This EPRI survey confirmed Hydro One's current asset management practices relating to transformers and the definition of Expected Service Life ("ESL") are aligned with industry best practices.

Depending on the type of transformer, Hydro One uses an ESL between 40-60 years, in line with industry peers. Hydro One uses asset condition as a primary driver for replacement, and all transformers undergo condition assessment to confirm the need for replacement. Replacement decisions take into consideration multiple factors, including an analytics algorithm as part of the assessment tool kit, which is common throughout industry. Hydro One has a formal process for assessing condition where the ultimate decision for replacement is made by a subject matter expert, which is in line with industry best practices.

3.2.4.5 ESL Survey of Circuit Breakers

This EPRI survey confirmed that Hydro One's asset management practices relating to circuit breakers are in line with best industry practices.

Hydro One uses 40 years as the ESL for circuit breakers and 50 years for oil circuit breakers in line with industry peers. In alignment with the majority of utilities in the industry, Hydro One proactively pursues replacements based on condition and reliability concerns. Hydro One does not operate equipment to failure. Hydro One has a formal process for assessing condition with the ultimate decision for replacement being made by a subject matter expert – which is in line with industry best practices. Recommendation for replacement takes into consideration multiple factors where an analytics algorithm is part of the assessment tool kit. Hydro One targets families of breakers for replacement if family-wide performance or condition issues are experienced (e.g., Siemens SP breakers).

3.2.4.6 Review of Utilities' Management of Air Blast Circuit Breakers

The data EPRI collected from this survey has demonstrated that Hydro One's approach to managing ABCBs is consistent with the industry. More specifically, the survey found that the both minor and major maintenance of ABCBs are "more" to "much more costly/difficult" to perform, and "less" to "much less reliable" when compared to single pressure gas breakers. Principal drivers behind programmatic replacement were operation and maintenance costs and an unacceptable level of reliability/availability. The population of ABCBs utilized by the utilities has been reduced by two-thirds over the last decade, with no new ABCBs currently being installed. The lack of available spare parts to properly maintain these types of breakers has become problematic for utilities due to the age of the technology and obsolescence. Hydro One currently has 133 ABCBs in its system. Over the next five years, Hydro One plans to remove 95 ABCBs from service and replace them with SF6 equivalents. For more details pertaining to this project, refer to SR-01 *Air Blast Circuit Breaker Replacement Projects*.

3.2.4.7 Review of Utilities' Management of Oil Circuit Breakers

The data EPRI collected from this survey has demonstrated that Hydro One's approach to managing Oil Circuit Breakers ("OCB") is consistent with the industry. More specifically, the survey found that the OCBs are somewhat "more costly/difficult" for purposes of performing both minor and major maintenance. OCBs are somewhat "less reliable" when compared to single pressure gas breakers. Principal drivers behind programmatic replacement are: unacceptable reliability/availability and insufficient ratings for below 138 kV; and excessive costs, environmental, and other for above 138 kV. The population of OCBs utilized by the utilities has been reduced by 18% over the last decade and nearly 85% of OCBs that are currently installed are over 40 years old. Utilities have diminished abilities to properly maintain oil circuit breakers as no utilities have dedicated crews to perform internal inspections/refurbishments or dedicated shops/contractors to maintain and overhaul oil circuit breakers. The higher cost and difficulty associated with maintenance requirements when compared to newer technology and the lack of dedicated crews to work on the ever-aging population of installed OCBs may lead to longer outage times associated with both routine and emergency maintenance. Hydro One currently has 1,600 OCBs in its system. Over the next five years, Hydro One plans to replace 247 OCBs with SF6 equivalents. OCB replacements are included as part of the following ISDs:

- SR-01 - *Air Blast Circuit Breaker Replacement Projects*
- SR-02 - *Station Reinvestment Projects*
- SR-03 - *Bulk Station Transformer Replacement Projects*
- SR-04 - *Bulk Station Switchgear and Ancillary Equipment Replacement Project*
- SR-05 - *Load Station Transformer Replacement Projects*
- SR-06 - *Load Station Switchgear and Ancillary Equipment Replacement Projects.*

For more details pertaining to these investments, refer to the ISDs noted above.

3.2.4.8 ESL Assessment of Specific Relays

This Kinectrics study was carried out to determine the risk associated with operating solid state and microprocessor relays beyond ESL and inform Hydro One of replacement pacing. The study was based on the samples of the currently in-service solid state and microprocessor-based relay population. These samples of relays were subject to accelerated aging tests. The report identified that the ESL range used by Hydro One is in-line with utility practice of 13 to 19 years for solid-state relays and a range of 13 to 20 years for microprocessor relays. The study results recommended Hydro One to increase the ESL for solid-state and microprocessor relays but did not provide a recommended ESL level.

While the study results confirm that Hydro One's ESL and treatment of these relays is appropriate and aligned with industry best practices. Hydro One will review its current practices and decision making process as well as continue to track and monitor the performance of its relays, based on the report's recommendations, to maximize the utilization of the relay fleet while managing its associated risk. For the time being, Hydro One will maintain the current ESL for all solid state and microprocessor-based relays systems as 25 years and 20 years, respectively as described in Section 2.2.

Specific integrated investments that include the replacement of protection system over the next five years are further described in ISDs SR-01, SR-02, SR-03, SR-04, SR-05, SR-06, SR-07, and SR-08.

3.2.4.9 Degradation Rates of Steel Tower Coating Systems

The EPRI study supports Hydro One's current investment plan by validating the existing approach and assumptions. Using the findings of the study, Hydro One continues to focus on coating steel structures in C4 and C5 corrosion zones whose age has reached 35-75 years of age.

3.2.4.10 Derivation of Overhead Conductor Hazard Function

The purpose of this EPRI study is to provide valuable insights into fleet mean life expectancy from analysis of historical condition assessment and replacement data pertaining to overhead conductors. In particular, this study presents EPRI's analysis to develop a conductor hazard curve and its ESL which can be used to project expected replacement needs for planning purposes.

As a result of the study, Hydro One has changed its conductor ESL from 70 to 90 years. The EPRI report forecasts that 3,920 circuit km of the ACSR conductor fleet will be at End-Of-Life ("EOL") or near EOL condition by 2024.[3] This forecast of ACSR conductor condition aligns with the fact that by the end of 2024, about 13% or 3,653 circuit km of the overall conductor fleet will reach or exceed their ESL without further replacements.

[3] TSP Section 1.4 Attachment 4 - Derivation of Overhead Conductor Hazard Function, section 5-3, p 93.

Hydro One only uses ESL for long term planning purposes and the planned conductor replacements are based on detailed condition assessments, Hydro One does not plan to increase its conductor replacement plan for the next 5 years based on EPRI's new ESL for conductors. Hydro One intends to replace 2,127 circuit km of conductor over 2020-2024 to address a prioritized subset of the existing ~3,680 kms of high risk conductors (13% of the fleet). The proposed plan will help with the pacing of the high risk conductor replacements over the longer planning horizon (i.e., the next 10 or 20 years) and also allow Hydro One to better manage the required capital expenditures associated with conductor replacement projects going forward.

Hydro One will continue to determine its conductor replacement needs through condition assessments and use ESL to only project replacement requirements for planning purposes. More details on overhead conductors that have reached or will reach their ESL during the test period are described in SR-19 and SR-20.

3.2.4.11 ESL Assessment of Specific Underground Transmission Cables

EPRI has determined the suitable ESL for low-pressure and high-pressure liquid-filled cables ("LPLF" and "HPLF", respectively) to be 70 years, as compared to the 50 years ESL previously used by Hydro One. Based on the newly established ESL, Hydro One is not projecting additional replacement projects beyond what is in the current investment plan. Hydro One forecasts that only 1.5% of the cable population will be beyond ESL by the end of 2024. As such, Hydro One will continue to monitor cable condition and repair or replace cables, as needed, to ensure a safe and reliable system operation. This study supports Hydro One's current condition-based replacement methodology.

3.2.4.12 Polymer Insulator Population Assessment

The focus of this study is to perform a detailed assessment of a sample of polymer insulators and to provide insights into overall population condition to inform Hydro One's replacement needs. Based on its assessment of 87 insulators, EPRI found that the condition of polymer insulators currently in-service in Hydro One's transmission system varies based on voltage, manufacturer and use of corona rings. Depending on the configuration, EPRI recommended an immediate removal, paced removal or continued monitoring. Hydro One is developing a program to identify locations requiring replacement and monitoring that will leverage current assessment programs. Hydro One will develop a replacement plan to address polymer insulators that are known to be in poor condition and will be structured to allow for appropriate investment prioritization and pacing. The current *Transmission Line Insulator Replacement* program (ISD SR-25) will prioritize the replacement of polymer insulators in deteriorated condition in and high risk porcelain insulators.

3.2.4.13 Phase 2: CP/COB Porcelain Insulator Population Assessment

This is Phase 2 of the 1965 to 1982 vintage Canadian Ohio Brass ("COB") and Canadian Porcelain ("CP") insulator population condition assessment study. Phase 1 was completed in 2016 and was intended to ascertain the urgency for taking action to ensure safety at publicly accessible locations. Phase 2 involved the removal of 591 insulators from service and detailed laboratory testing (compared to Phase 1) to further assess their long-term condition and assist Hydro One in prioritizing and pacing future replacements of these assets. The analysis of testing performed on these insulators provides overwhelming evidence supporting replacement to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation of this study is that the identified population of COB and CP insulators be removed from service as soon as practically possible. This study reinforces the urgency to increase pacing of CP/COB insulators replacement in non-critical locations. For more details on pacing and urgency to replace CP/COB insulators, refer to SR-25.

3.2.4.14 Asset Condition Assessment Process Review

In response to the findings in the OEB decision regarding Hydro One's 2017/2018 transmission application, Hydro One engaged Metsco to perform an Asset Condition

Assessment Process Review. The study reviewed Hydro One's Asset Risk Assessment ("ARA"), Asset Analytics ("AA") and decision-making process, the six criteria, methodology, and data inputs utilized to calculate asset scores, and identified areas for improvement and other recommendations.

Metsco's overall conclusion was that across the categories of the assessment, both the ARA and AA are adequately aligned to other asset management frameworks found in the industry and are sufficiently rigorous and robust to accomplish their intended tasks from the analytical perspective.

In light of the recommendations in the report, Hydro One will continue to collect relevant condition data and improve data governance to further enhance the asset management and decision-making processes. The recommendations from this review will inform Hydro One's efforts to continuously improve and enhance its asset management processes used for managing critical transmission infrastructure. As part of its commitment to continuous improvement, Hydro One has implemented enhancements to its Asset Analytics investment planning decision support tool in 2018. The enhancements updated the existing algorithms and weighting calculations to improve the quality of the asset risk model to better inform decision making.

3.2.4.15 Investment Planning Process Review

Hydro One engaged Boston Consulting Group ("BCG") to prepare this report in response to the OEB's request for Hydro One to review its investment planning process. This study confirms that, overall, Hydro One has implemented a consistent and thorough planning process that meets or exceeds expectations for an above average utility planning process, in all areas. This information supports Hydro One's submission that the investment planning process is robust and previous issues identified have been addressed.

In light of the recommendations of the report, Hydro One will continue to collect relevant condition data, update strategies, and implement forecasting outcome measures. Hydro One's progress regarding the implementation of these recommendations is provided in Attachment 15 to Section 1.4 of the TSP.

3.2.5 (5.4.1 B) HOW THE PLAN REFLECTS PERFORMANCE MEASUREMENT

As described in more detail in TSP Section 1.5, Hydro One is committed to achieving the productivity and cost efficiency goals outlined in its Business Plan. To give effect to this commitment, Hydro One has aligned its planning, execution and reporting functions around performance outcomes that are consistent with the OEB's RRF outcomes. The RRF outcomes relate to Customer Focus, Operational Effectiveness, Policy Responsiveness and Financial Performance. Hydro One's performance outcomes are reflected in its Transmission Scorecard (found in TSP Section 1.5, Figure 1), which assists Hydro One in transparently monitoring and measuring its performance relative to these outcomes. The evolution of Hydro One's Transmission Scorecard is discussed in TSP Section 1.5.2.

Key initiatives with respect to planning and execution have been undertaken to improve cost efficiencies and operating effectiveness. Hydro One is committed to achieving the incremental and continuous productivity and cost efficiency improvements included in its Business Plan. As described in TSP Section 1.6, both specific productivity initiatives and a Progressive Productivity Placeholder have been embedded within the Business Plan, reducing the revenue requirement, with corresponding cost control metrics reflecting improved levels of performance.

The evolved Transmission Scorecard establishes performance outcomes that Hydro One has targeted to achieve over the 2020 to 2022 test period and reflects Hydro One's commitment to achieve the performance outcomes for each measure through the execution of its 2020 to 2024 investment plan. The investment plan has been optimized so as to drive performance towards these outcomes, which reflect the need to ensure regulatory compliance and to appropriately balance the identified needs and preferences of Hydro One's transmission customers with Hydro One's transmission asset and system needs, while being mindful of the resulting transmission rate impacts.

In the context of the performance outcomes set out in the evolved Transmission Scorecard, the performance categories and measures corresponding to the outcomes of customer focus, operational effectiveness, and public policy responsiveness are particularly relevant to the TSP.

With respect to customer focus, Hydro One's commitment to service quality is reflected in its outage planning and coordination activities with customers. Customer preferences and priorities are to have safe, reliable transmission of energy with minimal outages. The transition to integrated investments was a core aspect of achieving this outcome. The integrated approach to investments provides not only efficiencies during the planning and design phases, but also greater efficiencies during construction and commissioning, leading to more effective outage coordination with customers. With an increased target of 90% Satisfaction with Outage Planning Procedures, the integrated investments for stations and lines highlighted in ISDs SR-01 to SR-08, and SR-19 to SR-20 will assist Hydro One in achieving this outcome.

Hydro One's objective is to engage with customers consistently and proactively. The Company's full spectrum of customer engagement initiatives is designed to: (i) increase the Company's understanding of customer needs and preferences; (ii) enhance Hydro One's ability to provide services that meet these needs; (iii) produce outcomes that are valued by customers; and (iv) result in an improvement in overall customer satisfaction with the services received from Hydro One. With an average of 84% overall customer satisfaction over 2014 to 2018, Hydro One has set an overall customer satisfaction target of 90 per cent over 2020 to 2024, which reflect an improvement over the long-run average through an ongoing focus on meeting expectations and delivering on critical success factors.

Safety, reliability and outage restoration are customers' top prioritized outcomes. Hydro One is committed to continuous improvement in operational effectiveness, and this TSP will deliver improved safety and system reliability outcomes. In addition, Hydro One plans to invest $17 million to mitigate the power quality impact of shunt capacitor bank switching on customers with sensitive equipment as highlighted in ISD SS-16. Hydro One's average frequency of sustained delivering point interruptions (T-SAIFI-S) performance over the past five years was 0.63 per delivery point, and the performance trend is indicating an increase in the average number of sustained interruptions per delivery point. Over the TSP period, Hydro One plans to improve against its historical average, targeting 0.52 interruptions per delivery point by 2022 and 0.5 interruptions per delivery point by 2024. Hydro One's Customer Delivery Point Performance Standard Outliers have historically been an average of 11.6% from 2013 to 2017, and over the term of this TSP, is targeting 10.8% by 2024.

Safety is a core value of the company, and Hydro One continues to pursue improvements in its safety record and achieve world class safety performance, as is reflected in the improved targets. The revised risk assessment process enables safety risks to be highlighted and mitigated through investments. Over the plan horizon, $3.5 billion of the proposed work program will aid in mitigating safety risks.

Continuous improvement in the execution of the plan includes dedicated efforts to improve Hydro One's project definition and execution capabilities to improve cost, risk and schedule management. In addition, the execution teams have an increased role during the Investment Planning Process to ensure the proposed plan is achievable. Employing the TSP Implementation Progress metric and Capital Program Accomplishment Index, Hydro One intends to deliver, monitor and pace work to accomplish the TSP in the plan period.

3.2.6 (5.4.1 B) HOW THE PLAN REFLECTS PRODUCTIVITY

To further its commitment to delivering outcomes that are valued by its customers, Hydro One has developed a comprehensive and rigorous process for identifying, developing, implementing, monitoring and measuring productivity initiatives that will reduce costs while maintaining or improving service quality and work outputs. Hydro One's commitment to achieving incremental and continuous productivity improvements is central to the planning and execution of work programs across the company. Within this framework, quantifiable productivity improvements are included in the Business Plan and corporate scorecards with clear accountabilities for delivering the anticipated savings. Using this approach, Hydro One has identified savings opportunities in capital and OM&A totalling approximately $704M over the plan period (2020-2024).

Hydro One has undertaken a number of productivity initiatives to reduce costs while maintaining or improving service quality and work outputs. The 2020-2024 TSP includes an incremental increase in productivity benefits over the previous plan. Hydro One has implemented a robust governance structure around productivity reporting to ensure productivity savings are accurately reflected on corporate scorecards and that there is continuity of savings in the Business Plan. The largest value initiatives included are related to:

- More effective procurement programs and fleet rationalization;
- Reductions in administrative expenditures enabled by software enhancements and improved process execution; and
- Rationalization of Information Technology spending

Out of total productivity savings of $704 million over the 2020-2024 period, $590 million is forecast to stem from the capital work program. Included within these savings is a progressive productivity factor on the transmission work program of 1% to 3% annually. This progressive productivity factor accounts for $286 million of the planned capital operations savings, as further discussed in TSP Section 1.6. This is a further reduction in cost that was applied to Hydro One's final transmission investment plan and represents a commitment from the company to find further efficiencies over the planning period to manage rate impacts when executing the necessary planned investments without reducing work volumes.

A detailed review of Hydro One's productivity initiatives as related to the TSP is set out in TSP Section 1.6.

3.2.7 (5.4.1 B) TIMING AND PACING

In determining the timing and pacing of its investments, Hydro One considered both its own ability to execute capital work efficiently and the ability to secure planned outage time to minimize impacts on customers and other stakeholders in Ontario. Given the condition and age of Hydro One's stations and lines, the deferral of work to future years will escalate the proportion of assets operating beyond their ESL and exacerbate the reliability impacts related to condition. A greater proportion of assets operating beyond ESL and in a condition requiring action results in increased future work requirements with existing planning, design, field and construction resources and work constraints related to outages. While replacements are condition driven, with condition assessments performed to verify whether an asset is a candidate for replacement, a correlation exists between operating the asset beyond ESL and the likelihood of that asset being in a deteriorated condition. Within a transmission system that has assets of high criticality, outage duration and frequency impact transmission customers both operationally and economically. This underlies the customer preference regarding reliability and outage management outlined above and in Section 1.3 of this TSP. If the demographic and condition pressures of assets operating at or beyond ESL are left unmanaged, Hydro One expects to face greater constraints to resources and outage scheduling in the future. As a result, Hydro One has planned the pace of renewal work so that certain critical work to reduce risks on the system could be completed in the planning period and investment levels are established in line with customer preferences.

3.3 CAPITAL EXPENDITURE DETAILS

3.3.1 (5.4.2, 5.4.3.1) CAPITAL EXPENDITURE TRENDS

Over the planning period, Hydro One plans to spend approximately $6.6 billion in capital representing an annual growth of 3.6% over five years to maintain transmission reliability performance, to address customer needs and preferences, and to mitigate asset and operational risks by accomplishing the planned capital work. The overall trend of the capital expenditures as it compared to the historical years is as follows:

- System Access – Capital expenditures over the test years are forecast to decrease compared to recent historical levels as a number of projects – Supply to Essex County Transmission Reinforcement, Enfield TS, and Runnymede TS, as well as the connection of Seaton MTS and Copeland MTS – are either complete or expected to be complete by end 2019.
- System Renewal – Capital expenditures increase compared to historical levels in order to address the demographic pressures through condition-based replacement of stations and lines assets.
- System Service – Capital expenditures return to historical levels after three years of lower spending as previous projects were completed and new ones are initiated over the test years.
- General Plant – Capital expenditures are in line with historical spending to support the operation and maintenance of the transmission system, with an increase in 2019 largely attributed to the construction of the new operations centre.

Hydro One's historical capital spending relative to planned amounts is shown in Table 1. Table 2 shows the forecast capital spending for the bridge year (2019) and TSP planning period.

Table 1 - Historical Capital Expenditure Summary

OEB Category	Historical (Previous Plan and Actual)											
	2015			2016			2017			2018		
	Actual	Plan	Var	Actual	Plan	Var	Actual	Plan	Var	Actual	Plan	Var
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
System Access	7.6	19.7	-61%	17.0	31.9	-47%	42.7	33.3	28%	33.7	24.3	39%
System Renewal	688.9	573.6	20%	733.9	539.9	36%	740.7	733.7	1%	776.2	780.4	-1%
System Service	157.9	189.9	-17%	140.9	180.0	-22%	93.5	97.0	-4%	73.9	75.6	-2%
General Plant	88.6	116.3	-24%	94.8	114.6	-17%	76.9	86.0	-11%	83.6	119.7	-30%
Total	**943.0**	**899.4**	**5%**	**986.7**	**866.3**	**14%**	**953.9**	**950.0**	0%	**967.3**	**1,000.0**	-3%
System OM&A[1]	441.6	431.2	2%	408.1	436.8	-7%	385.0	397.7	-3%	419.2	394.3	6%

[1] System OM&A includes Operations, Maintenance and Administration expenses. System OM&A for 2021 to 2022 is determined based on the Revenue Cap Index identified in Exhibit A, Tab 4, Schedule 1.

Table 2 - Bridge Year and Test Year Capital Expenditure Summary

OEB Category	Bridge	Forecast				
	2019	2020	2021	2022	2023	2024
	F/Cast	Test	Test	Test	Plan	Plan
	$M	$M	$M	$M	$M	$M
System Access	45.1	24.8	11.3	11.7	12.7	4.1
System Renewal	773.3	865.2	1,103.1	1,172.8	1,177.4	1,193.8
System Service	103.8	204.1	148.2	151.8	174.3	204.2
General Plant	116.3	115.4	94.4	94.7	83.6	58.9
Progressive Productivity Placeholder	0.0	-17.0	-39.0	-61.0	-78.0	-91.0
Directive[2]	**-0.3**	**-0.3**	**-0.3**	**-0.4**	**-0.4**	**-0.4**
Total	**1,038.2**	**1,192.2**	**1,317.7**	**1,369.6**	**1,369.6**	**1,369.6**
System OM&A[1,3]	**356.5**	**375.8**	*	*	**N/A**	**N/A**

For explanatory notes on Forecast Trends vs. Historical Budgets by Category, please see Section 3.3.2.

For explanatory notes on Plan vs. Actual Variance Trends by Category, please see Section 3.3.3.

For explanatory notes on System OM&A, please see Exhibit F.

[2] The Directive adjustment reflects the impact of the directive issued by Ontario's Management Board of Cabinet on February 21, 2019 and the associated framework they approved on March 7, 2019. Refer to Exhibit F, Tab 4, Schedule 1 for further details.

[3] Includes the Directive adjustment. Refer to Exhibit F, Tab 1, Schedule 1 for further details.

3.3.2 (5.4.2, 5.4.3.1) FORECAST TRENDS VS. HISTORICAL BUDGETS BY CATEGORY

System Renewal

System Renewal spending will increase above historical levels starting in 2019. Significant investment is required for the replacement and removal of air blast circuit breakers from the transmission network (ISD SR-01) at Bruce A and Bruce B transmission stations and increased load supply station reinvestment projects (ISD SR-02) including expenditures at the downtown Toronto station, John TS (ISD SR-08). Significant investment is also required over the plan to replace deteriorated and end-of-life transformers at load supply stations (ISD SR-05) as supported by the condition and performance considerations discussed in Section 2.2 of this TSP. The increased spending is needed to address an aging infrastructure, characterized by a large number of assets in poor condition and the strategic removal of air blast circuit breakers at critical stations. System Renewal investments will increase 5.5% over the course of this TSP, with investment in both stations and line refurbishment seeing a 5.7%, and 5.5% increase over the plan, respectively. The objective over the planning period is to return to top quartile reliability performance and this level of spending is designed to accomplish this objective.

System Access

System Access spending over 2020 to 2024 is expected to be be lower compared to historical levels as a number of major load connection projects (Supply to Essex County Transmission Reinforcement, Enfield TS, Runnymede TS, Seaton MTS and Copeland MTS) have been completed or expect to be completed by 2019. Generator connection projects have also been reduced as the IESO generation procurement nears completion.
The main investments over the forecast period include the connection of IAMGOLD and Metrolinx Traction Substations (ISD SA-01, SA-04), and expansion of Horner TS and Halton TS (ISD SA-02, SA-03).

System Service

System Service spending over the 2020 to 2024 period is expected to return to historical 2015 to 2016 actual levels after three years of lower spending in 2017, 2018, and 2019. System Service projects in these three years were not of the same magnitude as the major transmission projects identified in the previous rate applications such as the Midtown Transmission Reinforcement Plan, Guelph Area Transmission Project and the Clarington Project have either been completed or are in the final completion stage.

Spending level increases in 2020 with expenditures on major transmission projects such as: the Lennox TS Shunt Reactors (ISD SS-01), the Wataynikaneyap Line to Pickle Lake Connection (ISD SS-02), the East-West Tie Expansion (ISD SS-04), and the Barrie Area Transmission Upgrade (ISD SS-09) projects. In the 2022 to 2024 period, spending continues as work starts on the Leamington Area Transmission Reinforcement (ISD SS-13) and the Milton SS (ISD SS-07) projects. The East-West Tie Expansion, the Wataynikaneyap Line to Pickle Lake Connection, and the Milton SS projects are identified in the 2017 Long-Term Energy Plan.

General Plant

General Plant spending in 2018 remained in line with historical levels however spending is projected to increase through 2019 and 2020 before decreasing and returning to historical levels in 2021. The increases in 2019 and 2020 are attributed to increased spending in grid operating and control facilities associated with the new Integrated System Operating Centre (ISD GP-01). Spending in 2021 to 2022 declines to historical levels, while spending through 2023 and 2024 declines below historical levels as a result of the completion of investments associated with operating infrastructure that are required to sustain the grid control network (ISD GP-02), the network management system (ISD GP-03), and corporate services transformations (ISD GP-08). Investment in real estate and information technology remains in line with historical levels through 2024.

Investment in transport and work equipment (ISD GP-12) decreases from historical levels due to equipment right-sizing and telematics initiatives which took place in 2017, as described in Section 3.3.3. These initiatives have reduced Hydro One's fleet complement by 10%, resulting in reduced replacement levels in 2017 which persist through to 2024.

3.3.3 (5.4.2, 5.4.3.1) PLAN VS. ACTUAL VARIANCE TRENDS BY CATEGORY

System Access

Over 2015 to 2016, System Access investments were approximately $12 million, and $15 million below planned spending levels, respectively. These variances are attributable primarily to delays in the starting of the Seaton MTS and the Supply to Essex County Transmission Reinforcement projects. The spending for 2017 and 2018 was $9 million and $9 million above planned expenditure due to spending on the Supply to Essex County Transmission Reinforcement and Enfield TS projects.

System Renewal

In each year from 2015 to 2017, System Renewal projects were $115 million, $194 million, $7 million above planned spending, respectively. In 2018, System Renewal projects were $4 million below planned spending.

In 2015, integrated investments at several stations resulted in a net increase of $119 million to address significantly deteriorated and poor condition station assets including investments at Beach TS, Allanburg TS, Buchanan TS, Gerrard TS, and Hinchinbrooke TS. Additional increased costs associated with the timing of the Bruce A 230 kV ABCB replacement project (SR-01) and increased spending on emergency replacements and spare transformer purchases contributed to the variance. Transmission line refurbishments contributed an additional $21 million to the overage to address asset needs on circuits C25H, CxJ and CxZ, Q11S/Q12S, and D2L, but in total was offset by a $25 million reduction in planned spending on underground cable refurbishment due to delays resulting from project complexity and adjusted execution timelines for H2JK and a number of investments.

In 2016, investment in transmission stations saw an overall increase of $147 million to address deteriorated, poor condition assets in addition to projects from previous years that were under construction and had significant portions carry over into 2016 including work at Allanburg TS, Gerrard TS, and Beck 2 TS. Transmission line refurbishments contributed $62 million to the overage due to increased wood pole replacement needs based on poor condition and increased expenditures to replace defective CP/COB insulators to mitigate pu1blic safety risk. However, underground cable refurbishments resulted in a $15 million reduction in planned spending due to the complexity of the required environmental assessments and public consultation.

For 2017 and 2018, System Renewal projects were generally in line with planned spending. The primary driver of decreased capital spending below plan in 2018 was a result of the increased number of catastrophic transformer failures, namely those at Finch TS, Minden TS, and Nanticoke TS that required replacement along with associated restoration efforts to replace damaged and failed equipment, offsetting planned replacement work. Forecast expenditures for 2019 are in line with 2018 levels, maintaining the overall investment levels within the envelope afforded in Hydro One's 2019 transmission revenue cap adjustment application (EB-2018-0130).

System Service

From 2015 to 2016, System Service investments were approximately $32 million, and $39 million below planned spending annually. These variances are due primarily to cancellation of the Preston TS reinforcement project, deferral of the Cherrywood TS capacitor bank project, delay in the Midtown Transmission reinforcement project and the lower expenditures on the Guelph Area Reinforcement project and the Clarington TS project.

For 2017 and 2018, System Service spending was generally in line with total planned spending over that period.

General Plant

General Plant investments were $28 million below planned spending in 2015, $20 million below planned spending in 2016, and $9 million below in 2017.

In 2015, $23 million of the variance was the result of the continued transition to integrated investment planning which encapsulated operating infrastructure needs, and the delayed availability of new technology to meet operating requirements. $6 million was attributed to lower than planned costs associated with renovations and project delays in real estate and facilities investments. The decrease in spending was partially offset by an increase of $2 million in transport and work equipment due to the implementation of the approved telematics technology.

In 2016, reduced operating infrastructure spending contributed $20 million to the variance as a result of the review of the investment strategy due to technology advancements and functionality integration with existing infrastructure. In addition, $4 million of the variance was due to schedule and cost variance of the Integrated System Operating Centre ("ISOC") Project (ISD GP-01). Plans for a new Backup Control Centre ("BUCC") to replace the end of life BUCC were included and approved by the OEB as part of proceedings EB-2013-0416 and EB-2014-0140. The project had a planned in-service date of December 2018. In 2015, Hydro One decided to pursue a revised scope of the BUCC investment and instead, pursue the ISOC, which would increase the scope to include an Integrated Telecommunications Management Centre, Security Operations, an

Integrated Data Centre, and general back office space. The variance is a result of the change in scope and revised project schedule. Real estate and facilities investments under spending contributed an additional $11 million to the variance. However, the spending below plan was partially offset by a $13 million increase in Information Technology spending in 2016 driven by improvements to Hydro One's integrated financial planning and work management systems.

Spending in 2017 was approximately $9 million lower than planned expenditures primarily due to renovations and project delays in real estate and facilities investments ($2 million), lower spending on the ISOC ($2 million) largely due to savings realized during the detailed design phase and lower spending in Information Technology ($2 million).

Spending in 2018 is $36 million below planned expenditures, with a reduction of $25 million in grid operating and control facilities largely due to the ISOC. Hydro One realized there was a shorter construction window than previously estimated and the start date for the ISOC was deferred. Hydro One had reductions of $8 million in operating infrastructure due to redirection of investments, $14 million in facilities and real estate due to a mix of delays in commencement of several projects, as well as, lower than planned expenditures on others, and $7 million in transport and work and service equipment as a result of productivity gains due to right-sizing and deferral of expenditures due to fleet asset optimization and specification review.

These reductions are partially offset by an increase of $6 million in transmission site facilities to accelerate replacement of roofs at critical building on transmission station sites and $13 million in information technology ("IT") primarily driven by advancing spend related to Hardware/Software refresh and maintenance (ISD GP-07), minor fixed asset programs and an increase in common IT investments to make improvements to SAP and work management tools.

3.3.4 (5.4.2, 5.4.3.1) IMPACT OF CAPITAL INVESTMENT ON OPERATIONS, MAINTENANCE AND ADMINISTRATION SPENDING

Hydro One has a number of capital investments that reduce OM&A spending. Several examples of capital initiatives that reduce OM&A costs are listed below.

Hydro One is investing in the replacement of air blast circuit breakers, which are not only the poorest performing breakers on the system, but also contribute approximately $3 million in OM&A spending to maintain the associated high-pressure systems (ISD SR-01). Replacement of these breakers will enable the removal of the high-pressure air systems and the associated spending. On average, it is approximately 10 times more expensive to maintain an air blast circuit breaker and the ancillary components than the equivalent SF6 breaker.

Investment in the sustainment and replacement of obsolete and end of life station assets will result in downward pressure on OM&A spending. The replacement of poor condition oil circuit breakers will eliminate the need for oil sampling, and on high voltage oil circuit breakers - power factor/dissipation testing, also known as “Doble” tests. For transformers, Hydro One utilizes vacuum tap changers in place of oil filled units for replacement units, eliminating the need for future internal preventative maintenance. Replacement units are also deployed with low oil alarms and monitors, which eliminate manual oil level inspections.

Station reinvestment projects (see ISD SR-02) can reduce the number of transformers or breakers due to changes in the operating configuration of a station. Over the 2020 to 2024 planning period, 17 transformers, and 49 breakers have been identified for removal as a result of reconfiguration. The removal of these assets from the system eliminates all future preventative and corrective maintenance costs. Further detailed discussion on OM&A is included in the application throughout Exhibit F.

3.3.5 (5.4.2, 5.4.3.1) FORECAST AND HISTORICAL ASSET REPLACEMENT RATES

Hydro One's planned replacement rates are derived through the processes described in TSP Section 2.1, based on the assessment of the assets and system needs and asset lifecycle optimization (see TSP Sections 2.2 and 2.3). The historical and forecast rate of replacement for transmission stations and lines assets are noted in Tables 3 and 4 below.

The replacement rates shown below are the culmination of Hydro One's asset management and investment planning processes. In the context of System Renewal, for example, these processes have resulted in striking a balance between the asset needs (arising from age, condition, environmental and regulatory compliance), customer needs and preferences, and bill impact. Given the demographic pressures and impending wave of assets that will be at the end of their expected service life ("ESL") within the TSP period, Hydro One identified the following trends for each of the asset groups:

- Transformers – the proposed rate of replacement is largely in line with historical rates, and will ultimately maintain the percentage of the transformer fleet that operates at or beyond ESL
- Breakers – the proposed rate of replacement maintains the percentage of the breaker fleet that is operating beyond ESL at 12%.
- Protections – the proposed rate of replacement maintains protection systems that operate beyond their ESL at the current 27%.
- Conductor – the proposed rate of replacement mitigates the risk by managing the current 5% of conductor fleet that operates beyond ESL. Otherwise, the percentage of the conductor fleet operating beyond their ESL would have been 13% in the next five years which would create a high risk to manage.
- Wood Pole – the proposed rate of replacement maintains system reliability with a customer focus, as majority of wood poles are located in northern Ontario and

supply industrial customers on radial (single supply) feeds. Hydro One will maintain the rate of replacement to mitigate safety and reliability risk.

- Steel Structure – poor condition steel structures that are eligible for coating will be coated proactively at a pace aligning with the OEB's Decision and Order in proceeding EB-2016-0160.
- Insulator – the proposed rate of replacement focuses on public safety, by addressing insulators in critical locations first (road crossings etc.) followed by non-publicly accessible areas.

Table 3 - Asset Replacement Rates - Transmission Station Assets

	Historical				**Bridge**	**Test**			**Plan**	
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Transformer Portfolio										
# of Replacements	21	19	15	26	20	9	23	19	40	17
% of Fleet	2.9%	2.6%	2.1%	3.6%	2.8%	1.3%	3.2%	2.7%	5.6%	2.4%
Circuit Breaker Portfolio										
# of Replacements	31	73	108	148	88	135	105	88	215	95
% of Fleet	0.7%	1.6%	2.4%	3.2%	1.9%	2.8%	2.2%	1.9%	4.5%	2.0%
Protection Systems Portfolio										
# of Protection Replacements	445	627	298	184	453	465	370	503	681	384
% of Fleet	3.6%	5.1%	2.5%	1.5%	3.6%	3.7%	3.0%	4.0%	5.4%	3.1%

Table 4 - Asset Replacement Rates - Transmission Line Assets

	Historical				**Bridge**	**Test**			**Plan**	
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Conductor Portfolio										
kms of Circuit Replacements	201	183	119	51	140	64	483	795	309	475
% of Fleet	0.7%	0.6%	0.4%	0.2%	0.5%	0.2%	1.7%	2.7%	1.1%	1.6%
Wood Pole Portfolio										
# of Replacements	845	850	850	745	560	800	800	800	800	800
% of Fleet	2.0%	2.0%	2.0%	1.8%	1.3%	1.9%	1.9%	1.9%	1.9%	1.9%

	Historical				Bridge	Test			Plan	
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Steel Structure Portfolio										
# of Renewal	300	462	725	1050	220	260	500	500	500	500
% of Fleet	0.6%	0.9%	1.4%	2.0%	0.4%	0.5%	1.0%	1.0%	1.0%	1.0%
Insulator Portfolio										
# of circuit structures	155	2100	3422	3900	3700	3700	3700	3450	3450	3450
% of Fleet	0.1%	1.4%	2.6%	3.1%	2.9%	2.9%	2.9%	2.7%	2.7%	2.7%
Underground Cable Portfolio										
Kms of Circuit Replacements	0	0	0	0	4.7	0	0	0	0	7.2
% of Fleet	0%	0%	0%	0%	1.8%	0%	0%	0%	0%	2.7%

3.3.6 (5.4.3.2) MATERIAL INVESTMENTS

In accordance with Section 2.1.1 of Chapter 2 of the OEB's *Filing Requirements for Electricity Transmission Applications*, Hydro One's materiality threshold is $3 million. The following section describes investments included in this application that are greater than Hydro One's materiality threshold in any one year. It also identifies material investments that require leave to construct in accordance with Section 92 of the OEB Act as well as investments undertaken as a result of directives from the Ministry of Energy, Northern Development and Mines and investments that have been declared as a priority by the Governor in Council.

3.3.6.1 (5.4.3.2) LIST OF MATERIAL CAPITAL INVESTMENTS

The tables below provide a listing of Hydro One's Investment Summary Documents ("ISD"). Note that each ISD includes a priority.

- "**High" Priority** projects represent those that pose the greatest risk to the Hydro One system if not completed. Failure to complete these projects is expected to have significant impacts on the risk profile of the system in the short term. This includes demand-based work to address emergency replacements. This priority of projects also includes those required to ensure compliance with regulatory or legal obligations and customer agreements.
- "**Medium" Priority** projects represent those that pose a risk to the Hydro One system over the planning period if not completed. Failure to complete these projects is expected to have moderate impact on the risk profile of the system over the planning period. If reductions are required and sufficient savings are not available from the Low priority group, the Medium items would be reviewed as well for possible decreases in spending.
- **"Low" Priority** is for those projects ranking among the lowest group in the risk prioritization and optimization methodology. These projects are important to Hydro One but should a reduction in spending be necessary, Hydro One would

look at these projects first for reprioritization. Failure to complete Low Priority projects is not expected to have significant detrimental effects on the system in the near term.

Table 5 - System Access - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
SA-01	Connect New IAMGOLD Mine	24.9	0.0	0.0	0.0	0.0
SA-02	Horner TS: Build a Second 230/27.6kV Station	29.9	0.0	0.0	0.0	0.0
SA-03	Halton TS: Build a Second 230/27.6kV Station	8.0	17.7	6.0	0.0	0.0
SA-04	Connect Metrolinx Traction Substations	6.5	7.9	7.1	1.0	0.0
SA-05	Future Transmission Load Connection Plans	0.0	5.0	24.9	24.9	0.0
SA-06	Protection and Control Modifications for Distributed Generation	3.8	3.1	2.7	2.8	2.8
SA-07	Secondary Land Use Transmission Asset Modifications	55.1	15.0	13.9	15.6	3.9
	System Access Projects & Programs Less Than $3M	**27.6**	**9.4**	**8.5**	**7.8**	**9.2**
Total Gross System Access Capital ($M)		**155.7**	**58.1**	**63.0**	**52.0**	**15.8**
	Less Capital Contributions ($M)	*(130.9)*	*(46.7)*	*(51.3)*	*(39.3)*	*(11.7)*
Total Net System Access Capital ($M)		**24.8**	**11.3**	**11.7**	**12.7**	**4.1**

Table 6 - System Renewal - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
SR-01	Air Blast Circuit Breaker Replacement Projects	107.5	128.4	133.5	129.2	98.7
SR-02	Station Reinvestment Projects	107.0	125.4	120.6	87.9	53.9
SR-03	Bulk Station Transformer Replacement Projects	33.2	51.8	72.5	131.5	113.8
SR-04	Bulk Station Switchgear and Ancillary Equipment Replacement Projects	17.5	32.4	41.4	34.6	49.3
SR-05	Load Station Transformer Replacement Projects	91.2	132.3	129.4	178.5	200.0
SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects	19.2	30.8	47.5	58.4	77.0
SR-07	Protection and Automation Replacement Projects	6.7	8.6	12.7	12.2	21.7
SR-08	John Transformer Station Reinvestment Project	3.5	17.9	25.6	24.0	20.9

SR-09	Transmission Station Demand and Spares and Targeted Assets	44.2	36.4	37.0	37.7	38.3
SR-10	Transformer Protection Replacement	3.8	0.0	0.0	0.0	0.0
SR-11	Legacy SONET System Replacement	4.1	26.0	27.6	28.1	28.1
SR-12	Telecom Performance Improvements	0.0	0.9	5.5	3.7	0.0
SR-13	ADSS Fibre Optic Cable Replacements	7.0	7.1	1.0	0.0	0.0
SR-14	Mobile Radio System Replacement	2.9	6.2	6.1	4.0	0.0
SR-15	Telecom Fibre IRU Agreement Renewals	0.0	2.8	8.5	2.6	1.5
SR-16	NERC CIP-014 Physical Security Implementation	18.0	18.0	18.0	0.0	0.0
SR-17	NERC CIP Transient Cyber Asset Project	3.5	0.0	0.0	0.0	0.0
SR-18	PSIT Cyber Equipment Replacement	1.0	5.0	7.7	7.0	3.4
SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	81.8	122.1	94.5	51.0	75.9
SR-20	Transmission Line Refurbishment - Near End of Life ACSR Conductor	62.2	63.4	111.7	117.8	137.7
SR-21	Wood Pole Structure Replacements	51.0	52.0	53.0	54.1	55.2
SR-22	Steel Structure Coating Program	11.4	21.8	22.3	22.7	23.2
SR-23	Tower Foundation Assess/Clean/Coat Program	11.8	22.3	22.8	23.3	23.7
SR-24	Transmission Line Shieldwire Replacement	12.3	12.6	12.8	13.1	13.4
SR-25	Transmission Line Insulator Replacement	68.3	69.7	66.3	67.6	68.9
SR-26	Transmission Line Emergency Restoration	9.6	9.8	10.0	10.2	10.4
SR-27	C5E/C7E Underground Cable Replacement	2.1	29.8	30.9	32.2	29.2
SR-28	OPGW Infrastructure Projects	5.3	7.5	2.2	6.2	9.7
SR-29	Physical Security ISL Application Replacement	5.0	1.1	0.0	0.0	0.0
System Renewal Projects & Programs Less Than $3M		**77.8**	**67.3**	**60.1**	**44.1**	**41.1**
Total Gross System Renewal Capital ($M)		**869.1**	**1,109.2**	**1,181.1**	**1,181.5**	**1,194.9**
	Less Capital Contributions ($M)	*(3.8)*	*(6.1)*	*(8.3)*	*(4.1)*	*(1.1)*
Total Net System Renewal Capital ($M)		**865.2**	**1,103.1**	**1,172.8**	**1,177.4**	**1,193.8**

Table 7 - System Service - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
SS-01	Lennox TS: Install 500kV Shunt Reactors	32.3	0.0	0.0	0.0	0.0
SS-02	Wataynikaneyap Line to Pickle Lake Connection	24.9	1.5	0.0	0.0	0.0

ISD	Investment Name	2020	2021	2022	2023	2024
SS-03	Nanticoke TS: Connect HVDC Lake Erie Circuits	3.0	10.0	4.0	0.0	0.0
SS-04	East-West Tie Connection	46.3	38.8	22.6	0.0	0.0
SS-05	St. Lawrence TS: Phase Shifter Upgrade	9.0	18.0	9.0	0.0	0.0
SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	5.0	10.0	8.4	0.0	0.0
SS-07	Milton SS: Station Expansion and Connect 230kV Circuits	0.0	2.0	3.0	69.4	119.1
SS-08	Northwest Bulk Transmission Line	8.0	12.9	8.9	0.0	0.0
SS-09	Barrie Area Transmission Upgrade	38.1	28.2	8.5	0.0	0.0
SS-10	Kapuskasing Area Transmission Reinforcement	6.7	3.8	0.0	0.0	0.0
SS-11	South Nepean Transmission Reinforcement	27.5	10.5	0.0	0.0	0.0
SS-12	Alymer-Tillsonburg Area Transmission Reinforcement	10.0	13.1	6.1	0.0	0.0
SS-13	Leamington Area Transmission Reinforcement	4.9	9.7	59.1	63.8	63.8
SS-14	Southwest GTA Transmission Reinforcement	10.3	7.8	6.9	3.9	2.0
SS-15	Future Transmission Regional Plans	0.0	0.0	10.5	19.6	0.0
SS-16	Customer Power Quality Program	3.3	3.4	3.4	3.4	3.5
System Service Projects & Programs Less Than $3M		**9.1**	**8.2**	**9.9**	**14.0**	**15.9**
Total Gross System Service Capital ($M)		**238.3**	**177.9**	**160.3**	**174.3**	**204.2**
Less Capital Contributions ($M)		*(34.2)*	*(29.7)*	*(8.5)*	*0.0*	*0.0*
Total Net System Service Capital ($M)		**204.1**	**148.2**	**151.8**	**174.3**	**204.2**

1

2 **Table 8 - General Plant - Material Capital Investments Proposed**

ISD	Investment Name	2020	2021	2022	2023	2024
GP-01	Integrated System Operations Centre - New Facility Development	32.4	12.7	0.0	0.0	0.0
GP-02	Grid Control Network Sustainment	8.0	6.1	6.3	6.5	6.6
GP-03	Network Management System Capital Sustainment	0.0	7.8	22.4	8.2	0.0
GP-04	Integrated Voice Communications and Telephony System Refresh	0.0	1.9	3.2	1.1	0.0
GP-05	Transmission Non-Operational Data Management System	5.2	5.3	5.4	5.5	1.1
GP-06	Operating Common IT Infrastructure	0.8	2.0	3.7	3.3	2.2
GP-07	Hardware/Software Refresh and Maintenance	2.0	2.0	1.9	1.9	5.8
GP-08	Corporate Services Transformation - HR / Payroll	5.0	1.5	0.0	0.0	0.0
GP-09	Corporate Services Transformation - Finance	1.0	3.0	5.0	6.5	5.0

GP-10	Facility Accommodation & Improvements Service Centres & Admin	8.1	4.9	8.2	16.4	4.3
GP-11	Transmission Facilities & Site Improvements	9.4	9.5	9.6	9.7	9.9
GP-12	Transport & Work Equipment	13.2	13.2	13.3	13.3	13.3
General Plant Projects & Programs Less Than $3M		**30.2**	**24.3**	**15.8**	**11.1**	**10.7**
Total Gross System Service Capital ($M)		**115.4**	**94.4**	**94.7**	**83.6**	**58.9**
Total Net General Plant Capital ($M)		**115.4**	**94.4**	**94.7**	**83.6**	**58.9**

3.3.6.2 (5.4.3.2 D) SUMMARY OF INVESTMENTS REQUIRING LEAVE TO CONSTRUCT

Investments listed in Table 9 below are identified as requiring a leave to construct. Details of the evidence pertaining to the leave to construct are provided within the relevant ISDs.

Table 9 - List of Investments Requiring Leave to Construct

ISD	Investment Name
System Access	
SA-01	Connect New IAMGOLD Mine
System Service	
SS-04	East-West Tie Connection
SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade
SS-07	Milton SS: Station Expansion and Connect 230kV Circuits
SS-09	Barrie TS: Upgrade Station and Reconductor E3B/E4B Circuits
SS-10	Kapuskasing Area Transmission Reinforcement
SS-11	South Nepean Transmission Reinforcement
SS-12	Aylmer-Tillsonburg Area Transmission Reinforcement
SS-13	Leamington Area Transmission Reinforcement
SS-14	Southwest GTA Transmission Reinforcement

3.3.7 (5.4.3.2) INVESTMENTS UNDERTAKEN AS A RESULT OF DIRECTIVES FROM MOENDM/DECLARED AS PRIORITY

The investments listed in Table 10 are undertaken as a result of directives from the Ministry of Energy, Norther Development and Mines or identified as part of the Regional Planning process, as described in Section 1.2.

Table 10 - List of Investments Undertaken as a Result of Directives or Declared as Priority

ISD	Investment Name	Investment Rationale
System Access		
SA-02	Horner TS: Build a Second 230/27.6kV Station	Regional Planning – Metro Toronto
SA-03	Halton TS: Build a Second 230/27.6kV Station	Regional Planning – GTA West
System Service		
SS-01	Lennox TS: Install 500V Shunt Reactors	IESO Letter to Hydro One
SS-02	Watay Line to Pickle Lake Connection	LTEP, Regional Planning – Northwestern Ontario
SS-04	East-West Tie Connection	LTEP
SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	LTEP
SS-07	Milton SS: Station Expansion and Connect 230kV Circuits	LTEP
SS-08	Northwest Bulk Transmission Line	LTEP
SS-09	Barrie TS: Upgrade Station and Reconductor E3B/E4B Circuits	Regional Planning – Southern Georgian Bay/Muskoka
SS-10	Kapuskasing Area Transmission Reinforcement	IESO Letter to Hydro One.
SS-11	South Nepean Transmission Reinforcement	Regional Planning – Ottawa
SS-12	Aylmer-Tillsonburg Area Transmission Reinforcement	Regional Planning – London
SS-13	Leamington Area Transmission Reinforcement	Regional Planning – Windsor-Essex
SS-14	Southwest GTA Transmission Reinforcement	Regional Planning – Metro Toronto

3.3.8 (5.4.3.2) ATTACHMENTS: INVESTMENT SUMMARY DOCUMENTS

GP-01 Integrated System Operating Centre – New Facility Development

Start Date:	Q1 2015	**Priority:**	High
In-Service Date:	Q1 2021	**3-Year Test Period Cost ($M):**	45.2
Trigger(s): Immediate/Short-Term Compliance, Strategic, System Renewal, Reliability, Productivity Enablement, Cost Avoidance			
Outcomes: Improved reliability and availability of emergency activation, response and restoration, mitigation of existing critical risks, sustained monitoring and control reliability, maintenance of regulatory compliance			

A. OVERVIEW

This investment describes the construction and in-servicing of an Integrated System Operating Centre ("ISOC") and enabling the ISOC to serve as the primary operating control centre. The project, which began in 2015, provides for:

- A System Operating Division Control Centre;
- A Backup Integrated Telecommunications Management Centre;
- Primary facilities for Security Operations; and
- A shared integrated data centre and all critical support infrastructures at the preferred Orillia site.

This investment will maximize operational effectiveness, flexibility and scalability for Hydro One and associated lines of business while eliminating the need to duplicate investments at multiple sites and costly critical support infrastructure (e.g. emergency generators, uninterruptible power supplies, telecommunications, etc.).

The Ontario Grid Control Centre ("OGCC") is the current primary operating control centre and also functions as a data centre. The OGCC was built in 2003 and is currently at limited space capacity and in need of remediation to address heating and infrastructure concerns. In the event that the OGCC or its computer systems are rendered unavailable, an alternate facility is required to provide service continuity and maintain compliance with mandatory regulatory requirements.

Infrastructure problems, capacity constraints, and other site issues (e.g. flood risk) are impacting the viability of the existing Back-Up Control Centre ("BUCC") to provide service continuity and to maintain compliance with mandatory regulatory requirements.

The ISOC will serve as Hydro One's primary operating Control Centre. When the ISOC is fully in-service, the OGCC (which is the current primary operating control centre) will be re-designated as the backup centre and the existing BUCC will be decommissioned.

The investment in the ISOC, along with the re-designation of the OGCC and the decommissioning of the BUCC will allow Hydro One to address the deficiencies discussed above. This will ensure that the Company will have the necessary infrastructure in place to provide service continuity, maintain compliance with mandatory regulatory requirements, and will allow the Company to continue to effectively monitor, operate, control the transmission system, and continue to meet customer expectations.

The outcomes of the investment also include improved activation of emergency systems and protocols, response and restoration of power in the event of system faults, mitigation of existing critical risks at the control centres, sustained monitoring and control reliability, and maintenance of regulatory compliance. The projected transmission-allocated[1] costs of the project are estimated to be $45.2 million over the 2020-2024 planning period.

[1] Hydro One has used the approved Black & Veatch Common Asset Allocation methodology outlined in Exhibit F, Tab 2, Schedule 6 of the Application in order to allocate the costs between Transmission and Distribution.

B. NEED AND OUTCOME

Investment Need

Hydro One maintains primary and back up control centres to comply with regulatory requirements and to ensure business continuity remains at a service level that meets customer expectations at all times. These centres are governed by North American Electricity Reliability Corporation ("NERC") standards, the Transmission System Code ("TSC"), Hydro One standards, and other standards identified in the Investment Description section which follows. In particular, the NERC Emergency Operating Procedure standard EOP-008-02, "Loss of Control Centre Functionality", states that the transition period between the loss of primary control center functionality and the time to fully implement the backup functionality is less than or equal to two hours.

Hydro One's current primary control centre, the OGCC, has known deficiencies that include but are not limited to:

- A Heating, Ventilation, and Air-Conditioning ("HVAC") system which cannot handle summer heat loads and is normally complemented by a leased HVAC system;
- Data centre capacity constraints that are impacting business requirements and resulted in third-party lease costs for an off-site data centre;
- A sewage line under the control room which represents a challenge as repairs can only be done if the control room is shifted away from the OGCC for an extended time. This is continuously monitored closely and a repair plan remains a work in progress; and
- The existing facility is at capacity and lacks flexibility and scalability for any future system upgrades.

The inability to affect upgrades/replacements, increase capacity to computer systems and tools and makes necessary repairs to infrastructure, can result in significant disruption in Hydro One's ability to manage the Bulk Electric System ("BES").

The BUCC facility has been in service since 1956. The expectation is that it will not be a viable facility by 2021, due to infrastructure failures, capacity constraints, and inherent site issues that include the risk of flooding. For instance, the 2013 flood event in the Greater Toronto Area resulted in wide spread outage in the region, leading to an estimated unsupplied energy of 1,406,218 MW-minutes and $6.5 million in repair costs. The flood damaged computer room equipment and power supplies, rendering the BUCC unavailable for an extended period of time. The damaged systems that had to be replaced included but were not limited to: servers, server chassis, server racks, uninterrupted power supplies, routers, switches, cabling, and associated cable trays.

The BUCC also does not have the back office space capacity to support operations groups such as outage planning and operations studies and support that are fundamental to the daily operations of Hydro One's transmission network. A prolonged event would require the relocation of headquartered staff to make space for staff relocating from the OGCC, along with the procurement and set up of additional necessary computer equipment that would take time to implement. These challenges would impede the ability to maintain system integrity and reliability.

Furthermore, the BUCC is located adjacent to a major transformer station, exposing the facility to emergency preparedness risk including electrical hazards, environmental hazards such as fire, oil spills and other asset failure hazards (for example, transformer fires have previously rendered the BUCC unavailable). Increasing traffic congestion around the site, situated between two major highways, also compromises the ability to meet the two hour activation timeline mandated under NERC EOP-008-2. Other hazards include the centre's proximity to public storage facilities, gas pipelines, and its location directly below the flight path of a major international airport, increase the risk that the BUCC would become unavailable/inoperable.

In Hydro One's previous OEB rate filing applications, this ISOC investment was planned for a dual primary control and monitoring configuration, but to realize better operating synergies, it was decided that a single primary configuration will deliver more benefits. The updated plan involves making the ISOC Hydro One's primary control centre once it is fully in-service so that the deficiencies at the OGCC will be remedied without impact on real-time operations. The OGCC will then be re-designated as the backup centre. The existing BUCC will then be decommissioned. Incremental costs associated with this updated plan will only be from employee relocation considerations. This amount is forecast to be between $1 million to $3 million. The relocation cost will be budgeted as a one-time OM&A charge, and it is not included in this Investment Summary Document costing.

If the investment is not made on the proposed timeline, there will be an increased risk of future extended outages which will impact Hydro One's ability to effectively monitor, operate and control the transmission system, maintain regulatory compliance, and meet customer expectations

This proposed investment will provide for a new Integrated Telecommunications Management Centre ("ITMC") control room, replacing the existing Backup ITMC ("BUITMC") which will then be decommissioned. Hydro One Telecom, a subsidiary of Hydro One Networks Inc., operates and maintains mission-critical telecommunications services on a 24x7 basis. Hydro One relies on these telecommunications services to monitor and control the BES. The 2013 flood event made the primary ITMC unavailable. Telecommunication services were restored from the BUITMC that is currently located in a shared space at a remote transformer station that cannot accommodate a permanent active installation. This limitation in configuration resulted in delays during the 2013 Flood restoration efforts. The proposed investment is required to address this risk.

The ISOC would also incorporate a centrally located Security Operations Centre ("SOC"), which would provide physical security monitoring services. Hydro One Security Operations is currently reliant on an external third-party for primary and backup physical security monitoring services. Recent NERC trends indicate increasingly stringent security requirements are inevitable. Third-party security costs have been increasing as Hydro One requires additional monitoring and services due to increasing NERC regulatory requirements as it pertains to physical security monitoring of high impact facilities. Hydro One will improve its financial performance if some services are provided internally and third-party costs are reduced or eliminated. The establishment of a centrally located SOC to host all security management systems and servers would greatly reduce the risk of non-compliance with the NERC Critical Infrastructure Protection ("CIP") standard since NERC audit, assessment and compliance would then be conducted internally with a clear framework of ownership and accountability.

Investment Description

This investment involves the construction of a facility for the ISOC, enabling the ISOC to serve as the primary operating control centre. The ISOC will house multiple lines of business through the provision of dedicated control centres, an integrated data centre, and shared back office areas. This facility will be a hardened facility, built to withstand an EF3 tornado, and will reflect emergency preparedness criteria, industry best practices, and physical and cyber security standards. The facility is essential in maintaining the required redundancy in operations centres to ensure the reliability of the BES and associated customer responsiveness (i.e. outage and storm management).

Customers on the transmission system include large industrial companies and Local Distribution Companies, which identified the reliability of the BES as a top priority in the 2017 Transmission Customer Engagement survey. In addition, the ISOC will enable a coordinated approach to all real-time operating functions and continued adherence to NERC EOP-008-2, TSC requirements, and Hydro One standards. Conditions at the BUCC are deteriorating and there is a risk that these NERC requirements will not be met in the near future. The ISOC will allow for the provision of in-house security operations, thereby lessening reliance on costly third party services.

The ISOC design includes the following elements:

Facility:

- Provides the System Operating Division ("SOD") with a new control centre including a control room, back office space and a data centre;
- Provides the operating flexibility that allows Hydro One to accommodate industry modernization and future improvements;
- Mitigates the emergency preparedness risk and risk profile associated with the current BUCC as previously discussed;
- Ensures security requirements, both physical and cyber, including a hardened facility to guard against physical and environmental threats (i.e. tornadoes);
- Provides the ITMC with a new backup operations control centre including a control room, back office and integrated data centre mitigating the current risks at the BUITMC and the risks associated with a failure at the ITMC;
- Provide Security Operations with a headquarter location including a control centre, office space, investigative rooms, emergency operations centre (room) and integrated data centre; and
- Shared and redundant critical support infrastructure.

Site:

Provides a 16.57 acres site in Orillia, Ontario at an overall cost of $3.0 million, of which 49.93% is allocated to Hydro One transmission. The site was selected based on an extensive market assessment conducted in 2015 and was purchased in 2016 as part of Phase 2 of the project. The Orillia site met essential criteria, and included material advantages and associated cost savings in terms of location, current site development activities completed, existing water drainage/retention capability, improved commute and activation times, and significant municipal development charge savings realized through the Industrial Development Charge Moratorium offered by the City of Orillia.

Architecture and IT design:

The detailed design was completed in Q2 of 2017. The transmission portion of the total engineering and IT consultant costs, for the detailed design, was budgeted for $4.1 million.

Connectivity and Telecommunication:

Connectivity at the new ISOC facility allows for communication with OGCC utilizing the Hydro One telecommunication network. The transmission portion cost to establish this communication connectivity is estimated to be $6.7 million.

Network Infrastructure:

An additional $5.3 million (transmission portion only) has been budgeted for Information Technology ("IT") infrastructure. This covers the cost associated with connecting each individual workstation console to the ISOC data centre.

Compliance

Hydro One is required to follow a number of compliance requirements, public policy standards and internal standards relating to reliable system operations. In addition, industry best practices have been incorporated to safeguard reliability and availability of critical systems. The requirements that the ISOC must adhere to include the following:

1. NERC EOP-008-2 necessitating backup activation to be equal to or less than two hours.

a) In a related Federal Energy Regulatory Commission ("FERC") order[2], FERC signalled its concern that the two hour activation requirement is too long and that "it is imperative that full backup functionality occur as soon as possible after the loss of primary control functionality". FERC also noted that "…it may revisit this transition timeframe". This signalled that the new ISOC must take into consideration that activation timelines could be reduced in the future.

b) NERC and FERC also require the backup to be "capable of operating for a prolonged period and providing functionality sufficient to maintain compliance with all reliability standards that depend on primary control functionality." (NERC EOP-008-2, R3)

2. Restoration Participant Attachment as required by the Independent Electricity System Operator ("IESO") administered 'Market Rules' for the Ontario Power System Restoration Plan ("OPSRP"): the BUCC is listed as one of the key facilities which comprise Hydro One's contribution to the Ontario Basic Minimum Power System. Restoration participants are obligated, within the design and safe operation of their facilities, to help restore the grid after a partial or complete system blackout.
3. NPCC-D8 (NPCC Directory 8), "System Restoration" defines the Basic Minimum Power System Requirements, and outlines the redundancy requirements for computer systems, power supplies, and generators at these key facilities.
4. NERC EOP-005-2, "System Restoration from Blackstart Resources" is an obligation for transmission operators/owners to have plans, facilities, and personnel in place to enable system restoration following a disturbance,
5. NERC Critical Infrastructure Protection ("CIP") Requirements – ensuring assets are protected logically (electronic security perimeter) and physically (physical security perimeter).
6. Communications: NERC & IESO Market Rules:

[2] Docket No. RD11-4-000 at 14.

- NERC-COM-001-2 - Telecommunications
- Chapter 2, Appendix 2.2, Section 1.1.4- Technical Requirements: Voice Communication, Monitoring and Control, Workstations and Re-Classification of Facilities;
- Chapter 2, Appendix 2.2, Section 1.2.3 – Transmitter Submission to the Energy Management System;
- Chapter 5, Section 12.1.1 – Voice Communications Methods;
- Chapter 5, Section 12.1.6 & Section 12.2.12 – Alternatives During Loss of Communications;
- Chapter 5, Section 12.2.3 – Required Voice Communication Facilities;
- Chapter 5, Section 12.2.4 – Voice Communication Reliability;
- Chapter 5, Section 12.2.11 - Voice Communication Monitoring and Testing; and
- Chapter 5, Section 12.3.2 - Required Data Communication Facilities.

Additional Design Criteria

In addition to the above requirements, the following industry best practices have been incorporated into the ISOC design:

- Designed for increased security protection;
    - Improved system security and redundancy; and
    - Provides adequate setback and building wall enforcement to protect against small explosives; and
- Multifunctional Facility / Business Continuity
    - Increased building utilization (multipurpose, real time, and simulation);
    - Operational flexibility and scalability (modular expansion); and
    - Emergency Preparedness criteria – facility separation for common mode failure.
- High Availability / Reliability

- Employing the Uptime Institute guiding principles for a Tier III facility[3]; and
- Provides for redundancy in computing, communications, cooling and power.

- Emergency preparedness risk considerations were factored into site selection and facility design, mitigating the current risk the BUCC is exposed to (i.e. not in a transformer station, flight path, etc.).

Outcomes

The integrated strategy behind the ISOC facility reduces third-party costs, optimizing financial performance by also eliminating the need for additional sites and facilities that would otherwise be required. By building one centralized site to house all stakeholders, the following synergies will be realized: negating the need for multiple designs, development, sites, facilities (buildings), critical support infrastructure, future maintenance maximizing capital investment, limiting overall rate impacts.

All proposed tenants, including various lines of business departments such as the System Operating Division, Hydro One Telecom, Security Operations, and Power System IT, among others, require costly critical support infrastructure and IT investment to meet an availability target (99.95% uptime) commensurate with the criticality of the systems and functions they support. These requirements are prescribed by Hydro One internal reliability standards PP-66400-002-R1 and guided by industry best practices (Uptime Institute Availability - *Tier levels*, as outlined in Internal Power System Monitoring and Control Reliability Requirements PP-66400-002-R1 sections 4.1.2 and 4.1.8). With the current ISOC strategy, the critical support infrastructure is shared by the tenants and represents an incremental cost to achieve it rather than replicating the installations that would be required to support several sites across Ontario.

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[3] A Tier III data centre facility requires no shutdowns for equipment replacement and maintenance by including redundant power and cooling equipment and redundant delivery paths into the design. Uninterruptable Power Supplies, Computer Room Air Conditioning units, and standby generators are some of the components providing increased margin of safety to protect against disruptions.

The ISOC provides for:

- Enhanced monitoring, control and coordinated customer response (SOD, ITMC, Security and Emergency Preparedness) for all system vulnerabilities (i.e. system events, telecommunication events, cyber events or physical threats through integrated communication within the ISOC facility).
- Shared enhanced building protection design and security (physical facility hardening to protect against severe weather or man made threats);
- Shared redundant backup generator power supply and other emergency supplies;
- Enhanced site location for improved activation response, adherence to emergency preparedness criteria, and other business operations;
- Enhanced centralized security operations, improved monitoring and analysis trending for proactive response, and situational awareness for coordinated resolution; and
- An Emergency Operations Centre for Business Continuity and Emergency Preparedness will also be provisioned as part of the SOC

The following table summarizes the anticipated benefits as a result of this project:

Customer Focus	• Improve the reliability and availability of emergency activation, response and restoration if system fault events are experienced. • Reduce rate impacts from a single integrated solution as compared to multiple standalone investments. • Retiring of the current SOD BUCC arrangements and removal of the risk of costly remedial efforts in the event further failures are experienced.
Operational Effectiveness	• Mitigates the critical risks (infrastructure failures, capacity constraints, location and activation timelines etc.) that exist at the SOD OGCC and BUCC and the BUITMC. • Monitoring and control reliability will be sustained under all system contingency scenarios reducing compliance risk and improving customer responsiveness and operational capability.
Public Policy Responsiveness	• Satisfy regulatory requirements for physical protection, cyber security and activation timelines responsiveness. (See *Appendix A* and *Compliance* sections of this document for further details).

Financial Performance	• Allow the deficiencies at the OGCC to be addressed in a planned manner that facilitates better cost control. • Reduce the risk of costly mitigation in the event additional failures are experienced at the main BUCC (2013 flood event resulted in $6.5 million in repair work).

C. EXPENDITURE PLAN

Key considerations affecting the final cost of the project consist of the following:

- Availability and reliability standards include the need for redundancy in system and building architecture to maintain the existing Hydro One target of 99.95% availability. To achieve a higher reliability, additional facility redundancy support will be implemented at the ISOC such as the Uninterruptable Power Supply, multiple utility power supply, and multiple lines of communication. The largest cost element revolves around the data centre and critical support infrastructure, and the *Tier* or *redundancy* level can weigh heavily on the required investment. Given the criticality of the control centre functions, with leading industry advice, a Tier III+ level was recommended and designed. The industry standard for this type of critical facility is actually Tier IV, which some other utilities have chosen to build to. Due to the high cost associated with building a Tier IV facility, and after a meeting with various Hydro One internal stakeholders and IT experts, it was decided that a Tier III+ design would suffice for Hydro One's purposes. This category includes investment in the telecommunications network required to connect the new ISOC to the OGCC and field assets for monitoring and control.
- Security requirements impose additional cost considerations ensuring the facility can withstand both natural and human events (i.e. tornado, adequate setback from security perimeter). Included in this consideration are prescribed regulatory requirements for six sided secure perimeters, cyber security, site access and monitoring of critical assets. The six sided secure perimeters is a requirement from NERC with respect to any space that is designated as a Physical Security Perimeter (“PSP”) area. This standard requires that the four walls, ceiling, and flooring surrounding the area must

be protected, monitored and secured to avoid trespassing and other security concerns. For example, if the door allowing for access to the PSP area is held open for an extended period of time, it is required that an alarm is sounded and the incident is tracked accordingly.

Costs have been managed through an extensive and thorough assessment with various third party industry experts, internal subject matter experts relating to industry best practices, and cost saving initiatives (such as the *free-cooling*[4] design), alternative option assessment for independent project elements (site selection, industry comparators) and integration of solutions for various business units, functions and needs across Hydro One at a single site.

An independent cost consultant has provided a Class A +/- 5% cost estimate on the construction of the facility. Hydro One requested an update to the cost estimate in late 2018 to understand changing economic conditions. Skilled trade labour rate escalations, new foreign tariff structures, and competition for local construction resources resulted in an increase to the cost estimate. The updated cost estimate was then used to evaluate vendor bids through the RFP process.

The ISOC project started in 2015 and will continue until anticipated in-service in 2021. Prior year spending (Table 1) indicates the total costs incurred prior to the test period.

[4] Free cooling design is a way to optimize overall cooling/energy cost in the data centre.

Table 1 – Total Project Costs

($ Millions)	Prior Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital* and Minor Fixed Assets	34.6	32.4	12.7	0.0	0.0	0.0	0.0	79.8
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**34.6**	**32.4**	**12.7**	**0.0**	**0.0**	**0.0**	**0.0**	**79.8**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**34.6**	**32.4**	**12.7**	**0.0**	**0.0**	**0.0**	**0.0**	**79.8**

D. ALTERNATIVES

Alternative 1: Status Quo/ Use Offsite Leased Space

Hydro One SOD maintains the existing control room, and Security Operations maintain existing security arrangements. A new offsite leased data centre facility (to mirror capacity of the OGCC data centre based on a 20-year lease and initial setup costs) could be provisioned and additional office space would be required and furnished for prolonged activations. This alternative includes additional leased space for the BUITMC control room and compute needs. The total cost of this option is estimated to be $83.1 million, of which the transmission portion would account for 49.93%.

This alternative has been rejected as the current SOD BUCC and the BUITMC do not meet operational requirements:

- The current facility imposes a high level of risk to both regulatory compliance and, Hydro One's reputation and customers, if any failures are experienced;
- This alternative fails to provide for the SOC need for an adequate primary control centre, and fails to address the third party risks of Security Monitoring;

- Even with extensive investment in the existing facilities, this option does not adequately remediate all operational effectiveness risk factors (e.g., electrical hazards due to proximity to TS, traffic congestion adversely impacting activation, basement flooding, and power capacity constraints);
- This alternative cannot accommodate current or projected growth, requiring future investments;
- This alternative would require the relocation of the existing compute space and critical support infrastructure, currently housed at the BUCC, to a new leased space to be shared with the BUITMC; and
- This alternative cannot mitigate all known risks due to site conditions, size and location. In the event of a prolonged activation, some existing staff of the BUCC facility must leave to make space for operating activities, and even if this arrangement can be made, there is insufficient onsite parking, workspace, and basic facility infrastructure for the overflow of staff.

Alternative 2: *Build a modified version of ISOC on the preferred Orillia Site*

There are multiple build configurations which were considered as alternatives to the recommended investment:

1. Removing the Telecom Control Centre (reduction of $22.2M), and/or
2. Removing the Security Operation Centre(reduction of $11.5M),

Depending on which scenario(s) are selected, the estimate for these alternatives ranges from $126.1M to $148.3M, which the transmission portion would have been 49.93%. . These alternatives were rejected as analysis showed that the recommended ISOC alternative provided the best long term value and efficiency of risk mitigation for Hydro One and its customers.

Due to the importance of the ITMC, the identified need for a new BUITMC and the financial performance that would be foregone, this removal of the BUITMC was rejected.

The exclusion of the SOC was rejected, because it fails to maximize financial performance through synergistic lines of business occupancy and maximize use of shared critical infrastructure. Bringing SOC services to the ISOC will reduce security monitoring service OM&A cost by approximately $0.6M on an annual basis. This SOC exclusion also fails to leverage operational effectiveness synergies for operational response to security threats, both physical and cyber. By co-locating physical security monitoring (i.e. SOC) with the other lines of business, opportunities for collaboration on physical risk mitigation will be optimized. The risk of third party contractors for physical security monitoring will be eliminated.

Alternative 3: Acquire an existing facility that could be retrofitted / utilized to accommodate SOD Control Centre, BUITMC and an integrated Data Centre

A market assessment was completed that reviewed potential sites against identified requirements for size, location, travel times, power infrastructure, telecommunications and occupancy. This also included an internal assessment of Hydro One owned sites. At the completion of the assessment, it was determined that no suitable site was available in the market or within Hydro One owned locations. As a result, this alternative was excluded from further consideration.

Retrofitting an existing facility was also considered in connection with this alternative. In order to provide the environment and critical support infrastructure required for data centre reliability, continuous (24x7) control rooms, and security considerations (including dual power supply and telecommunications expansions), extensive investment would be required. At the time of the assessment, no suitable site/facility was available and as such this option was removed from further consideration.

Alternative 4: Initiate Build of the Integrated System Operations Centre (“ISOC”) (*Recommended*)

This alternative provides for:

- A SOD Control Centre;
- A BUITMC;
- Primary facilities for Security Operations; and
- A shared integrated data centre and all critical support infrastructures at the preferred site.

This alternative will maximize operational effectiveness, flexibility and scalability for Hydro One and associated lines of business while eliminating the need to duplicate investments in multiple sites, and costly critical support infrastructure (emergency generators, uninterrupted power supplies, telecommunications, etc.). This alternative is estimated at a cost of $159.8 million, of which, the transmission portion would be 49.93%.

This option involves building the ISOC to serve as the primary operating Control Centre. When the ISOC is fully in-service, the OGCC, which is the existing primary operating control centre, will be re-designated as the backup centre and the current BUCC will then be decommissioned.

Further details about the project are included in Appendix A.

A detailed option comparison is included in Appendix B.

E. EXECUTION RISK AND MITIGATION

- Construction commencement is contingent on the required OEB approvals and if not planned accordingly, could pose project schedule risk. This has been mitigated through a schedule adjustment that will initiate commencement once the OEB has provided a decision on both Transmission and Distribution portions of the investments.
- Municipal approvals pose risk to the project schedule. During the current detailed design phase the municipality has been consulted throughout the process, thereby mitigating the risk of future change requests or delay for approvals. Building permits are needed for construction. This ensures compliance with zoning requirements, health, fire, structural safety standards and other building standards.
- Site development and environmental risk may result from the discovery of adverse subsoil conditions. This risk has been mitigated through several borehole assessments of subgrade soil conditions to determine: (a) foreign objects; (b) soil contaminants; and (c) suitability of soil cohesion for adequate foundation strength and no notable issues have been discovered.
- Construction risk results from change requests, proponent's lack of performance and increased costs. These risks have been mitigated through plans for Hydro One and the external designer to monitor construction site activities throughout construction. This will ensure issues are discovered in a timely manner and addressed as soon as possible and that required contract quality is delivered.
- Alignment of dependent sub-projects has been identified as a potential risk. A delay in delivery of communication path connectivity to the control network would delay future *in-service* date and commissioning activities. This risk is mitigated through early commencement of this activity to ensure adequate lead times.
- Factors affecting priority are those identified in the *Investment Need* section that describes the increased reliability risk. These factors have been reviewed and reprioritized as *high* given the cost for remedial efforts such as those resulting from the 2013 flood in Toronto and the impacts on operations and Hydro One customers.

APPENDIX A – DETAILED PROJECT DESCRIPTION

This investment, formerly known as the Backup Control Centre – New Facility Development, has expanded to include other operational synergistic lines of business that require facilities to perform similar functions (operating, monitoring, control and response functions) that are critical to support SOD and to secure Hydro One's assets. An integrated solution was sought to ensure costs are minimized, maximizing the effective utilization of critical infrastructure, office space and the site and reducing customer rate impacts. Below is a description of the SOC and the ITMC identified investment need.

The BUITMC facility, in-service since 1950, requires extensive setup during activation and cannot accommodate back office support staff and regulatory security requirements for access control for critical computing equipment due to physical space limitations. The current HVAC is not adequate for net new occupancy or equipment and lacks the necessary facilities should a prolonged activation be required. The ITMC is a mission-critical element in ensuring that telecommunications network is available and in providing first level support in the event of any communications failure. Without the telecommunication connectivity from the OGCC to the stations, the OGCC is unable to monitor and control the BES. In the event the ITMC cannot meet its service objectives, and Hydro One experiences an issue with telecommunications paths, SOD will be unable to monitor or control the respective field assets. The ITMC requires a new Backup Control Centre to alleviate the risk at the current location.

A SOC and an Emergency Operating Centre are required to provide a primary site for operations, monitoring and coordinated response for physical security threats and are imperative for business continuity. Currently, Security Operations are dispersed across the province and are reliant on third party services. In the event the current vendor cannot meet service obligations, an eventuality that has occurred historically, Hydro One will be unable to monitor its critical sites. An integrated security presence at the ISOC will ensure physical threats can be detected, assessed and appropriate response dispatched. If a physical threat goes undetected, catastrophic impacts may result if critical assets are damaged. This has the potential to result in severe impacts to the Transmission and Distribution system networks across the province. In addition, a lack of detection has potential to expose Hydro One to public and employee safety and environment risk.

The current ISOC investment has evolved through a significant collaborative effort with Hydro One SOD, ITMC, Security Operations, industry participants and external subject matter experts. Initiation of this investment was predicated on current asset driven deficiencies/requirements (i.e. documented safety hazards, capability constraints, reliability/performance impacts and risks, failures, condition, age, obsolescence, and regulatory and/or Hydro One standards as described above).

Below is a detailed description of the ISOC investment planning process and execution strategy, which has been developed with the aim to a) fully understand requirements and needs across Hydro One, b) gather leading industry best practices and lessons learned, c) develop detailed programmed space and sizing requirement and assess against industry benchmarks, d) seek project costing from leading industry experts, and e) ensure cost controls and oversight.

Planning Needs Assessment: Phase One

Requests for Proposals (“RFP”) were issued to conduct a market scan and a planning needs assessment. This provided a detailed assessment of sites available in the market that met a set of specific “essential location requirements” and to provide expertise into the conceptualization and documentation of business needs and requirements of SOD, ITMC, and SOC. The main focus was balancing needs and costs against reliability requirements, industry best practices (including feedback from New York Independent System Operator and New England Independent System Operator) and lastly with lessons learned from the Ontario Grid Control Centre (OGCC) build. In addition, business requirements were translated into programmed space requirements based on Hydro One's experience and at the advice of industry experts. A basis of design was developed, capturing the stated requirements and a cost estimate was provided by an external estimator (for building and support infrastructure) and internal Hydro One engineering groups (for Telecommunications and Dual Power and Power System IT). The final basis of design and cost estimate was utilized to initiate the subsequent detailed design phase.

The sizing of the ISOC is predicated on duplicating the OGCC current functions. The new ISOC facility will be able to continue all day to day functions indefinitely.

Security Operations sizing was predicated on defined needs of operators, support staff, an investigation room and an Emergency Operations Centre (which will utilize a shared conference room when required).

The ITMC Backup Control Centre duplicated the current primary centre exclusively, including control room space, data centre requirements and provisions a back office support compliment to ensure adequate facilities are available for prolonged activation redundancy and assurance of operations.

Detailed Design and RFP: Phase Two

At the completion of the planning needs assessment phase, a detailed design phase commenced with the objective to provide all required documentation, designs and costing to tender the end state solution for construction. During this phase, all drawings, facility programing (space definition), IT architecture etc. were completed, including site procurement (~$3 million) and a final estimation. This information was packaged and ready for submission for RFP for the construction phase. RFPQ was completed in December 2017. The official RFP documents were issued to the shortlisted vendors in 2018.

Hydro One sought to pre-qualify a select number of vendors, in a competitive open market process, who demonstrated "required competencies" (e.g., proven large project construction experience, defined safety/environmental programs, change control process controls, demonstrated ability to deliver large construction projects on time and to budget, etc.) required for the construction of the ISOC. Pre-qualified vendors were required to offer input with respect to areas which could result in increased costs if not addressed before construction and provide a *Guaranteed Maximum Price* proposal to a defined scope of work and schedule, linked to a delivery penalty.

Construction Phase: Phase Three

The current plan is for the successful proponent to commence construction in Q2 2019.

Post Construction award: Hydro One's engineering consultants will monitor on site activities throughout the construction to identify issues early in the stage and solve them as soon as possible, and ensure quality is delivered according to the standards. Hydro One will participate in interactive bi-weekly onsite construction process meetings to gauge progress to requirements and address any potential concerns.

Other Risk Considerations:

The ISOC investment has been identified as a high priority as the historical failure issues at the OGCC/BUCC demonstrate the demand for the ISOC, which will become a critical facility in managing the BES. The project was subsequently prioritized and planned due to risk and considerations described below.

Current BUCC site location risks that will not be remedied include the following:

- Travel time to the current BUCC site location necessitates an interim backup facility to perform limited functions in the event the OGCC or its computer systems are rendered inoperable to comply with the NERC-mandated activation time of two hours. The ISOC will eliminate this risk;

- BUCC structure is landlocked with no expansion potential as the facility is surrounded by a transformer station;
- Current emergency preparedness risks will remain, which will be mitigated by decommissioning the BUCC, and replacing it with the OGCC:
- Adjacent to a major transformer station which exposes the BUCC to the following emergency preparedness risk: electrical hazards, environmental hazards such as fire, oil spills and other asset failure hazards.
- In a congested area in the event of wide spread emergencies i.e. civil unrest, blackout, natural disaster, terrorism at Pearson International Airport, which would negatively affect the mandated two-hour activation timeline.
- Between two major highways (Hwy 427 & Hwy 401)
    - The BUCC is adjacent or close to multiple highways (Hwy 401, Hwy 409 and Hwy 27) so any spills or major motor vehicle accidents could lead to an evacuation.
- Adjacent to public storage facilities.
    - Risk of terrorism and other disturbances as there is insufficient setback with neighbouring businesses.
    - The nature of high profile neighbouring businesses poses additional risk to Hydro One's ability to access and maintain a prolonged activation without further disruption (e.g. 1980s bombing of nearby industrial company).
- Gas pipelines located underneath property.
    - A pipeline failure leading to an explosion or a leak resulting in an evacuation is an example of very high consequence event, but carries a low probability.
- In a flight path (Pearson International Airport).
    - There are over 1,100 daily flights in and out of Pearson International Airport.
    - Given the proximity to the runway, an airplane crash during take-off or landing is an example of a very high consequence event, which could render the BUCC inoperable, but carries a low probability.

- Facility risks that could render the BUCC or critical equipment unavailable for an extended period of time, eliminating redundancy of critical monitoring and control of the transmission system include:
  - Basement flooding where computer rooms, power rooms, telecom rooms, switchgear, and SONET communications are currently located;
  - Failures of critical support infrastructure including; the fire panel, HVAC, emergency backup power (generator);
  - Inability for expansion and a high cost for retrofit / maintenance activities;
  - Relocation to the main floor of the equipment located in the basement of the facility is not a viable option given the space required for Computer rooms, telecommunication gear (SONET), Uninterrupted Power Supply units, switchgear etc.;
  - Competing demands for physical space, power, cooling from multiple tenants; and
  - Electrical station service is undersized.
- ITMC's current backup centre, the BUITMC has the following documented risks and constraints;
  - Located in a shared space with an inability to expand;
  - Requires extensive setup during activation as the facility cannot accommodate a permanent active installation;
  - Cannot accommodate current back office support requirements;
  - Cannot meet security requirements for access control for critical computing equipment;
  - The current HVAC is not adequate for net new occupancy or equipment;
  - Lacks the necessary facilities should a prolonged activation be required; and
  - ITMC is a mission-critical element in ensuring that the System Operations telecommunications network is available and in providing first level support in the event of any communications failure.

Hydro One's Security Operations are currently reliant on an external facility that is owned and operated by a third-party creating corporate and regulatory risks under NERC CIP standards, given that Hydro One lacks a contingency site that is capable of monitoring the physical security of its sites and assets. Should the facility or third party services no longer be available to Hydro One due to factors outside of Hydro One's control, Hydro One will not be in a position to monitor the real-time security (including door alarms, motion sensors etc.) of its critical sites, creating both a security and public and employee safety risk. Such an occurrence would also lead to a regulatory non-compliance violation with NERC Standards and possible sanctions, financial penalties and risk to corporate reputation.

APPENDIX B – DETAILED ALTERNATIVE COMPARISON

Detailed Alternative Comparison

Alternative	Description	Cost ($)	Size (ft^2)	Site (Acres)	Cost / ft^2	OM&A**	Comments/Additional Considerations
Alternative One: Status Quo	Maintain existing facilities. (BUCC remediation activities, lease new data hall space, lease for BUITMC).	$83.1M*	18,921	N/A	N/A	N/A	No provision for SOC. Existing BUCC location, space, and site constraint risks remain. Significant difficulties for prolonged activation. Includes a leased space for BUITMC, leased Data Centre space for SOD and remedial work to retrofit office space to better accommodate prolonged activation.
Alternative Two	Build SOD BUCC and Data Centre.	$126.1M* - $148.3M*	95,420 - 99,716	16.41	$1,322 - $1,487	$2.4M yearly and one-time charges of $3.6M	Site, SONET, Dual Power and critical support infrastructure included. This includes the preferred site and all critical support infrastructures including but not limited to: telecommunication, Dual Power, redundant generation, UPS, cooling, shared office and common space
Alternative Three	Acquire an existing facility for BUCC and BUITMC and integrated Data Centre	Not available. Building specific market scan by Andrew Thompson and Associates (ATA) indicated no suitable site for consideration at time of assessment. Hydro One owned sites were reviewed internally; however also found that no suitable site or facility existed that meet the business requirements.					

Alternative	Description	Cost ($)	Size (ft^2)	Site (Acres)	Cost / ft^2	OM&A**	Comments/Additional Considerations
Alternative Four	Initiate Build of ISOC.	$159.8M*	126,200	16.41	$1,266	$3.4M yearly and one-time charges of $7.6M	Provides a SOD primary control centre, BUITMC, and primary SOC including shared integrated data centre, and back office support staff area. Current lifecycles for critical applications respected, alleviating addition IT requirements to enable primary operability. This option assumes that direct SOD operating staff would be moved to the new ISOC and the current OGCC used a Backup.
Ontario Grid Control Centre (data for comparison purposes)		$154.4M	68,000	9.25	$2,271	$1.5M yearly	Presented in 2018 dollars (originally $118M investment in 2003). Provided for comparison.

*The Transmission portion of this total is 49.93% of the total cost.

**The OM&A cost estimates are the full total cost and these have not been adjusted to show the transmission portion only.

Data Centre Construction vs. Leased Data Centre

In addition to the alternatives discussed above, Hydro One retained an engineering firm, Morrison Hershfield to conduct a comparison between the option of construction versus a comparable co-location or leased data centre option. This ensured that the most cost effective means of providing needed Data Centre space is to build/acquire a new facility. The data centre space is the largest cost consideration in the overall project total. The Morrison Hershfield assessment was based on a 15 year term at market prices in the Greater Toronto Area ("GTA"). The GTA was utilized for this study as it provided a much larger pool of lease options with the required reliability / Tier level standards. The results of the 2016 study shown below indicate that the co-location/lease option ($122.1 million), based on the current design criteria, far exceed the cost of the build option ($73.2 million) ($30 million in Capital + Incremental annual OMA at $2.5 million escalated at 2% per year for 15 years, $43.2 million).

	IT/POWER MRC*	**Annual Cost of Rent**
Year 1	$ 341,144.00	$ 4,093,728.00
Year 2	$ 372,529.25	$ 4,470,350.98
Year 3	$ 406,801.94	$ 4,881,623.27
Year 4	$ 444,227.72	$ 5,330,732.61
Year 5	$ 529,725.56	$ 6,356,706.73
Year 6	$ 529,725.56	$ 6,356,706.73
Year 7	$ 578,460.31	$ 6,941,523.75
Year 8	$ 631,678.66	$ 7,580,143.93
Year 9	$ 689,793.10	$ 8,277,517.17
Year 10	$ 753,254.06	$ 9,039,048.75
Year 11	$ 822,553.44	$ 9,870,641.24
Year 12	$ 898,228.35	$ 10,778,740.23
Year 13	$ 980,865.36	$ 11,770,384.33
Year 14	$ 1,071,104.97	$ 12,853,259.69
Year 15	$ 1,169,646.63	$ 14,035,759.58
	Total 15 Year Spend	$122,636,866.99

**MRC = Monthly Recurring Charges include IT load rent, estimated power charges and PUE of 1.6.*

***Pricing in this table and this section are 2016 dollars.*

Other factors that affected this consideration are: a) no co-location facility provides NERC certified space which would require additional upfront capital cost in the first year, and b) many facilities have policies that dictate access, upgrade, expansion and security for the facility without renter input which exposes Hydro One's critical equipment to further risks.

Comparisons to Similar Facilities at Other Utilities

In a separate study, Hydro One asked Morrison Hershfield to compare the ISOC build cost with other critical utility builds that they are familiar with and the findings are presented in the table below. SaskPower was used as the reference utility for the comparison per below.

ISOC Breakdown	**Est. Cost**	**ft^2**	**Report Findings of Morrison Hershfield ("MH") on Build Comparisons**
Building Shell Cost	$30M	120,534	Includes shell and basic Mechanical Electrical Power services. This is considered at the bottom of the range of $250/ft^2 -$1000/ft^2 for hardened facilities of this type, which equals the cost per square foot for SaskPower's most recent facility design. Variance consisted of EF3 Tornado rate vs. EF4 for SaskPower with less office space and did not have Control Room space. Average generic office space range from $150 -250/ft^2. dependent on finish and furnishings.
Data Centre Cost	$30M	11,990*	SaskPower's estimates cost per ft^2 for data centre space was $3,000/ft^2. and it is MH's conclusion that $2,502 is within range of similar facilities. A similar telecom project in 2015 with a similar Tier level as the ISOC was $2575/ft^2.
ISOC Total	$159.8M**	126,200	This includes Building Shell, Outdoor Yard and Data Centre.

**Included support galleries (cooling, power distribution).*

***Note: The Transmission portion of this total is 49.93% of the total cost.*

Lastly, Hydro One reviewed a number of utilities investments in facilities and data centre development projects to ascertain the reasonableness of the ISOC scope as compared to the rest of the industry. Below is a table summarizing these findings; which show the ISOC is in line with the cost per square foot for comparable projects.

Industry Comparators	Description/Name	Cost ($M)	Size (ft^2)	Year Built	Adj. Cost to 2018 $ (CPI)	Cost (2018 $) / ft^2
New York Independent System Operator	NYISO Control Center	$59.4M	64,000	2014	$64.22M	$1,003
American Electric Power	Transmission Operations center	$57.2M	83,500	2007	$71.46M	$856
ISO-New England	Windsor Backup Control Centre	$50.7M	70,000	2014	$54.81M	$783
Pacific Gas & Electric	Distribution Control Center	$52.0M	37,674	2015	$56.27M	$1,494
	Distribution Control Center	$37.05M	24,000	2014	$40.05M	$1,669
	Distribution Control Center	$46.8M	50,000	2016	$49.95M	$999
First Energy	FirstEnergy Tx Control Centre	$58.5M	70,000	2013	$64.24M	$918
BC Transmission Corporation	System Control Modernization Project	$133M	113,022	2008	$159.34M	$1,410
	System Control Centre (building ONLY)	$40M	64,584	2008	$47.92M	$742
	Backup Control Centre (building ONLY)	$30M	48,438	2008	$35.94M	$742
Average Cost :				-	-	$1,141
Transmission Portion of ISOC.		$79.8M	63,851.5	2021	$79.8M	$1,250
Proposed ISOC Cost Comparison		$159.8M	126,200	2021	$159.8M	$1,266

Converted from USD to CDN at an exchange of 1 USD to 1.3CDN

Note: The ISOC is comprised of Distribution, Transmission, ITMC and SOC.

Site Assessment

As per the table below, the average cost per acre for the sites South of Barrie are higher than the costs per acre for the sites North of Barrie. In light of the foregoing, the City of Orillia was chosen as a primary location for the ISOC, given its relative location compared to the OGCC, the City size, access, lodging, development and emergency services, including the OPP headquarters. Communities further away were ranked lower due to distance, access to emergency services, development and lodging, winter driving hazards and relative site suitability among other factors.

Ranking	Community	# of Sites	Ave. Cost / Acre
1	City of Orillia	4	$114,935 - $181,200
2	Town of Bradford	3	$346,636
3	Town of Collingwood	3	$135,469
4	Town of Midland	6	$90,000
4	Town of Penetanguishene	3	$87,500
5	Town of Alliston (New Tecumseth)	3	$273,900
6	Town of Newmarket	2	$850,000
7	Town of Orangeville	1	$215,000
8	East Gwillimbury	6	$400,000
9	Angus	1	$80,000
10	Innisfill	0	$ -
11	Schomberg (King Township)	1	$475,000
12	Wasaga	0	$ -

Note: An assessment of internal Hydro One TS sites was reviewed against available acreage and emergency preparedness criteria and was determine that there was no existing Hydro One site that could accommodate the proposed facility. This represented a departure for previous assumptions with impacts of land purchase and support infrastructure that must be extended to the preferred site.

GP-02 Grid Control Network Sustainment

Start Date:	Q1 2020	**Priority:**	High
In-Service Date:	Program	**3 Year Test Period Cost ($M):**	20.5
Trigger(s): Strategic, Cost Avoidance, System Renewal			
Outcomes: Cost Savings, Regulatory Compliance, Replacement of End of Vendor Support Hardware			

A. OVERVIEW

The Grid Control Network is a computer network which allows Hydro One controllers located at the Ontario Grid Control Center ("OGCC") in Barrie ON to continuously monitor and control the Hydro One grid. Information from the Grid Control Network is also passed on to and utilized by external parties, such as other utility control centers, customers, and the IESO.

This program involves the replacement of both end of vendor support and components which are approaching end of vendor support of the Grid Control Network. It also migrates the Grid Control Network to a new and simplified network topology. The new network topology removes hub sites as well as Local Control Computers ("LCC") and Local Maintenance Computers ("LMC").

Hub sites were necessary in the past to act as a regional consolidation point for Supervisory Control And Data Acquisition ("SCADA") information from Hydro One stations. Over the last 20 years the need for hub sites has diminished due to two reasons:

1. The majority of Hydro One stations now have local protocol conversion, a necessary step to transmitting SCADA information to Hydro One's OGCC. When hub sites were first deployed they performed protocol conversion for the Hydro One stations connected to it because the equipment at Hydro One stations was unable to perform this protocol conversion.

2. Telecom circuits have migrated from older point to point connections to modern IP based routable circuits. These newer circuits do not have the same geographic limitations.

LCCs and LMCs are separate Windows based computers used in Hydro One stations. The LCC function is to provide local control of the primary power equipment within the station. The LMC function is to interface with protection and control equipment within the station in order to assist field staff with commissioning and troubleshooting activities. The new network topology migrates the function of the LCC into the station gateway. The function of the LMC has been replaced by the Transient Cyber Asset ("TCA") – a secure USB based operating system issued to field staff, used in conjunction with their corporate laptops. The removal of the LCC and LMC from Hydro One stations is preferred because:

1. It removes the need to update the Microsoft Windows operating system at Hydro One stations.
2. It reduces the amount of equipment which needs to be commissioned and maintained at Hydro One stations.

Gateways are a critical component within the Grid Control Network because they perform the necessary protocol conversion describe above as well as act as a concentration point for SCADA information. The majority of Hydro One's gateways will lose vendor support on June 30, 2022. Other existing hardware – Remote Terminal Units ("RTU") have already lost vendor support, and are targeted for replacement. RTUs are important in the Grid Control Network because they interface with the primary yard equipment at a station to execute control operations initiated by the OGCC. Proactive phased replacement of this hardware is necessary due to the critical importance of the Grid Control Network to the daily operation of Hydro One's transmission system. Unreliability of the Grid Control Network due to a lack of vendor support would pose operational risks.

The migration of the Grid Control Network topology to a new, simplified topology would allow Hydro One to eliminate hub sites (which as explained below, are no longer necessary and add unnecessary processing delays) thereby ensuring Hydro One satisfies the IESO Market Rules[1] that require high performance telemetry measurements have data measurement/equipment status change available at the IESO communications interface in less than two seconds.

This program will impact approximately 40 hub sites and 300 stations. One existing hub site will remain at Manby TS in order to accommodate the requirements associated with certain minor Hydro One transmission assets, as well as its transmission connected customers.

B. NEED AND OUTCOME

Investment Need

The Grid Control Network provides monitoring capabilities and remote control of the assets at Hydro One stations to the OGCC and Backup Control Center ("BUCC"). It is critical to Hydro One's real time operation of its transmission grid and is necessary to ensure safe, reliable and efficient power delivery.

This investment is required to: (i) replace elements of the Grid Control Network that are at or approaching end of vendor support, including: RTUs, LCCs, LMCs and gateways, and (ii) facilitate the migration of the Grid Control Network to a new network topology.

(i) <u>Replace Grid Control Network elements</u>

As described above, gateway hardware within the Grid Control Network will lose vendor support on June 30, 2022. It is impossible to predict when the existing gateways will fail.

[1] IESO Market Rules, Chapter 4, Appendix 4.21 – IESO Monitoring Requirements: Transmitter Performance Standards.

If the gateways are left to run until failure, a large portion of the gateways at existing Hydro One hub sites may fail at the same time, raising the cost to replace many gateways concurrently.

Furthermore, Hydro One also has an installed base of legacy RTUs which are well beyond end of vendor support and in need of replacement. Proactive phased replacement of this hardware is necessary due to the criticality of the Grid Control Network to the daily operation of the transmission system. Unreliable performance of the Grid Control Network would pose operational risks and challenges for the OGCC.

At the station level, the Grid Control Network allows centralized control of primary yard equipment (such as a circuit breaker, or disconnect switch) from an LCC. More specifically, the LCC is a Microsoft Windows based computer which allows local field staff to monitor and control station assets from centralized locations within the station. The Microsoft Windows operating system software for existing LCCs, which requires regular updates, will lose vendor support by January 14, 2020. This program will replace the LCC with a Human Machine Interfaces ("HMI"). HMI's are software feature enhancements that will be purchased for the new station gateways. The HMI will replace the functionality previously provided by the LCC, thus eliminating the need for the LCC. The proposed HMI within the station gateways are superior to the LCC as they do not have the same end of support issues associated with Windows based computers and will instead have the same lifespan as the station gateway hardware.

LMCs are Windows based computers installed in Hydro One stations which help facilitate commissioning and maintenance activities by field staff. As described above, the LMC function has been migrated to the TCA, and they have become redundant. LMCs face the same software lifecycle problems as LCCs. This work will decommission LMCs in Hydro One's stations.

(ii) Migrate to New Topology

From a network perspective, this program will also implement a new and simplified topology for the Grid Control Network, which eliminates all but one existing hub site at Manby TS. The hub sites were put in place when the OGCC was originally built almost two decades ago. Their function is to perform protocol conversion and provide a consolidation point when connecting telecom (Bell S4T4) circuits to Hydro One stations. Over time, Hydro One stations have been equipped with their own protocol conversion and the telecom circuits at stations have transitioned to be IP-based, therefore eliminating the need for information to be relayed through a hub site before reaching the OGCC. Figure 1 provides a diagram of the existing network topology, and the simplified topology to be implemented is illustrated in Figure 2 below.

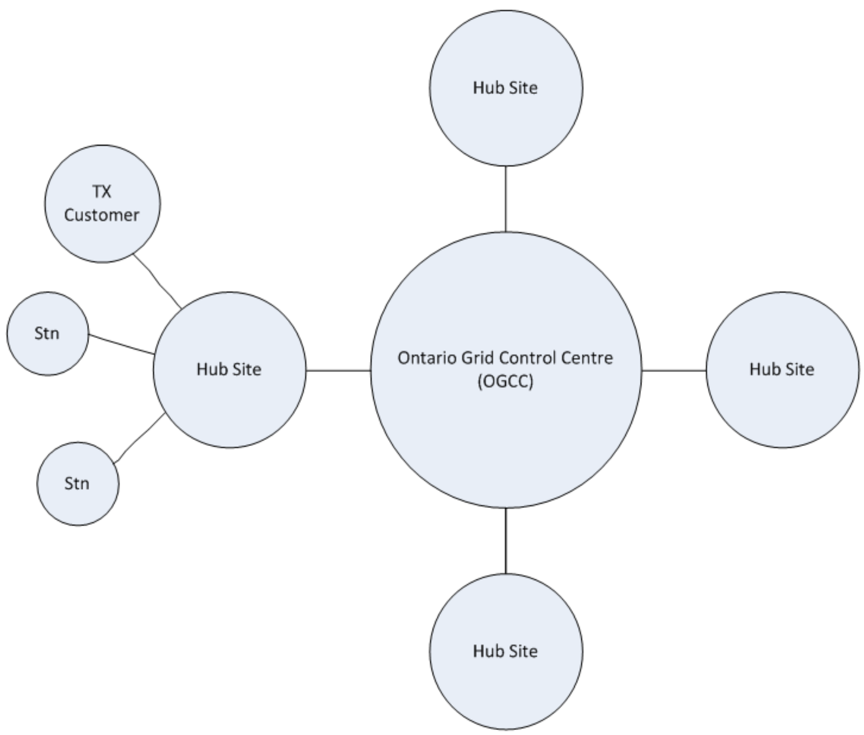


Figure 1 – Existing Network Topology

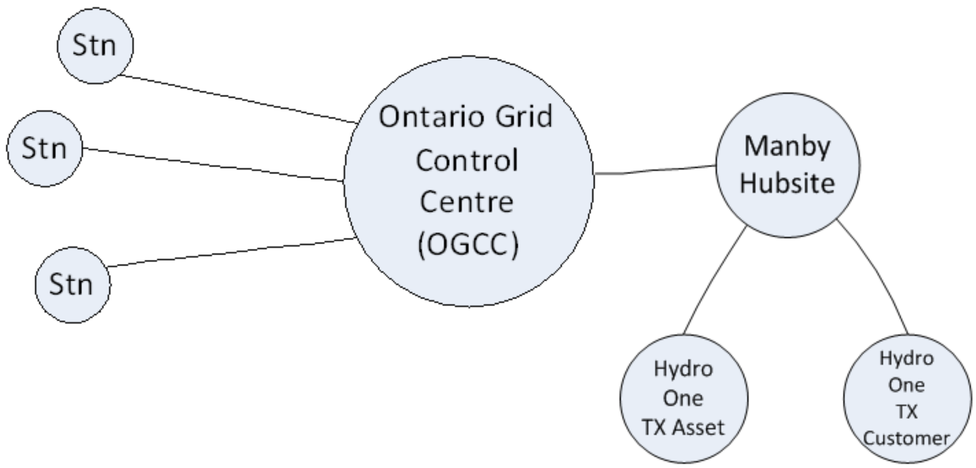


Figure 2 – Simplified "New Proposed" Network Topology

This new and simplified configuration is desirable and necessary because it would allow Hydro One to meet the IESO Market Rules requiring high performance telemetry measurements have data measurement/equipment status change available at the IESO communications interface in less than two seconds. Each additional level of hardware inherently introduces a processing delay. Therefore, by removing the hub site, the processing time of the relevant equipment is reduced, increasing the speed of the high performance telemetry measurements on the whole. Connections to the Manby TS hub site will not have this requirement, because they will be classified by the IESO market rules as medium performance telemetry measurements. The Manby TS hub site will remain solely for the purpose of (i) processing SCADA information from Hydro One transmission assets which currently do not warrant having their own local protocol conversion; and (ii) processing and consolidating SCADA information from Hydro One's transmission connected customers. Additionally, the new network topology is simpler, reducing the potential points of equipment failure and increasing the reliability of the Grid Control Network.

Investment Description

As explained above, this investment entails the replacement of equipment in Hydro One's Grid Control Network that are at or approaching end of vendor support, and the migration of the Grid Control Network to a new architecture. At each station there are four major components of work to be carried out as part of this investment:

(1) Upgrading the station gateway with HMI;
(2) Implementation of new Grid Control Network topology;
(3) Removal of LCCs and LMCs;
(4) Replacement of legacy RTU (if applicable).

All components of this work are related, and Hydro One will utilize a "bundling" approach (i.e. perform all components of the work concurrently at a station) in order to reduce costs and shorten timelines. An additional aspect of this program work will be to reroute some Hydro One transmission assets to the Manby TS hub site. These transmission assets which are currently connected to existing Hydro One hub sites are unable to perform their own protocol conversion. This is necessary to ensure that hub sites in our existing network topology can be removed from service, thus realizing the new Grid Control Network topology.

There are approximately 300 Hydro One stations to be addressed through this program work. Every year a list of stations will be addressed based on their criticality to the Grid Control Network. The cost of doing this work at each station will vary depending on its size and complexity of the local network. Program funding levels are expected to be higher in 2020, due to the additional expense of work performed at larger, higher priority stations. Implementing the required changes at these stations will be more costly given there will be more equipment to replace, remove, and test. In general, larger stations that are subject to NERC Critical Infrastructure Protection ("CIP") requirements are given higher priority. Program funding levels remain steady past 2022 to focus on replacing the remaining legacy RTUs. Due to the volume of work, it is not possible to complete all four work components by the end of 2022 at all of Hydro One's stations. Legacy RTU replacement, although important, is less important than the remaining three work components.

Hydro One's objective is to ensure the Grid Control Network equipment is replaced and fully migrated to the new network topology by the end of 2022 (with the exception of the legacy RTUs). This work cannot be deferred largely for three reasons:

1. If the network continues to operate with end-of-support hardware and an issue arises, there will be no support available. The overall reliability of the Grid Control Network would be impacted, which is of critical concern since it is relied upon by the OGCC to operate the transmission system.
2. Hydro One has a large installed base of RTUs in the Grid Control Network that are no longer supported by vendors. Due to their age, these RTUs have a high risk of failure. If repair is not possible with available spare parts, a RTU replacement will have to be engineered as a reactionary project, resulting in a lengthy equipment restoration time.
3. The new network topology will ensure Hydro One is compliant with IESO market rules.

Outcomes

There are a number of significant benefits to performing this work:

1. *Addressing end of life station computers (LCCs and LMCs):*
   LCCs and LMCs currently use either Windows XP or Windows 7. Windows XP is no longer supported by Microsoft. Windows 7 will lose all support on January 14, 2020. LCCs provide the important function of local control of primary yard equipment. They will be replaced by station gateway HMIs. The HMI will allow the continued local control of station primary yard equipment. LMCs support field staff in commissioning and maintenance activities. Their function has been

replaced by the TCA. The elimination of LCCs and LMCs will mitigate Hydro One's reliance on Windows based software at its stations.

2. *Addressing end of life gateways:*

   Gateways are a critical part of the Hydro One Grid Control Network. Vendor support for the gateways installed at the majority of the stations ends June 30, 2022. Gateway replacement will ensure reliability of the Grid Control Network, as well as facilitate the removal of the LCC at Hydro One stations.

3. *Addressing end of support RTUs:*

   RTUs are a critical part of the Hydro One Grid Control network. Hydro One has an install base of approximately 32 older RTUs which are well beyond vendor support. This investment will systematically replace these RTUs with units that are aligned with Hydro One's current design standard. Retired RTUs will be kept as spares until the entire install base is upgraded.

4. *IESO Monitoring requirements:*

   The IESO Market Rules require high performance telemetry measurements have data measurement/equipment status change available at the IESO communications interface in less than two seconds. The new network topology will ensure that this requirement is met by eliminating the processing delay currently introduced through the existing hub sites.

The following table presents anticipated benefits of the investment in accordance with the Ontario Energy Board's ("OEB") Renewed Regulatory Framework ("RRF"):

Customer Focus	• By migrating to the new topology the total amount of equipment in the network is reduced, thereby reducing the possible points of failure, resulting in the network becoming more reliable. This will improve Hydro One's ability to safely and effectively operate its transmission system. As a result, customers will experience fewer and shorter service interruptions.
Operational Effectiveness	• Migration to the new Grid Control Network topology allows Hydro One to meet IESO monitoring requirements. • When a hub site has its gateway files reconfigured the information collected from all of its remote stations becomes unavailable. As stations are migrated off the hub sites such that information is relayed directly to the OGCC, loss of availability will only be experienced by the station being worked on. This will improve system performance by reducing the number of stations impacted by routine station work.

C. EXPENDITURE PLAN

Through this investment, a certain number of stations will be addressed each year in a phased manner, so as to complete the required work at approximately 300 stations by the end of 2022. The estimated costs shown below have been determined on a per unit basis, with reference to the volume of equipment at each station. The per unit cost was estimated based on historical costs of the same work performed at previous stations.

Larger stations that are more critical to the Bulk Electrical System have been prioritized. The target date to complete the migration to the new network architecture is the end of 2022. Funding levels remain steady in 2023 as the focus of the program shifts resources on legacy RTU replacement.

Table 1 - Total Investment Cost

($ Millions)[1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	0.0	8.3	6.3	6.5	6.7	6.8	0.0	34.6
Less Removals	0.0	0.3	0.2	0.2	0.2	0.2	0.0	1.0
Gross Investment Cost	**0.0**	**8.0**	**6.1**	**6.3**	**6.5**	**6.6**	**0.0**	**33.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**8.0**	**6.1**	**6.3**	**6.5**	**6.6**	**0.0**	**33.6**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown
[2] Includes Overhead at current rates.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred option:

Alternative 1: Status Quo

Alternative 1 is to maintain existing Grid Control Network equipment until the work described by this investment can be bundled as part of other integrated station work. The current integrated station investment practice at Hydro One is to evaluate the need to perform work at each station on a seven year cycle. Under this option, end of vendor support equipment would not be replaced in a timely manner. Operating equipment without vendor support reduces the reliability of the Grid Control Network, which is critical to the daily operation of the transmission grid. Additionally, replacement parts for failed end of vendor support components will become harder to obtain over time. For these reasons, the status quo alternative is not recommended.

Alternative 2: Replacement of Grid Control Network elements without Vendor Support

Alternative 2 is to only replace the elements of the Grid Control Network that are no longer supported by vendors, without addressing the migration of the Grid Control Network to its new network topology. This alternative is not recommended, as it will impede Hydro One's ability to meet the IESO Market Rules for high performance telemetry. Additionally, Hydro One will not benefit from the increased reliability that could be achieved by the reconfiguration of the Grid Control Network, and will not realize the cost efficiencies associated with executing both components of this investment at the same time.

<u>Alternative 3: Replacement of Grid Control Network elements without Vendor Support and migration of the Grid Control Network to its new network topology (*Recommended*)</u>

The recommended alternative is to replace the elements of the Grid Control Network that are at or approaching end of vendor support and migrate the Grid Control Network to its new network topology. The existing station gateways will be replaced with versions that incorporate HMIs, and LCCs and LMCs will be removed. By the end of 2022, all eligible Hydro One stations will be migrated to the new network architecture. From that point forward, the program will focus on legacy RTU replacement.

This alternative minimizes Hydro One's operational risk by proactively replacing equipment in the Grid Control Network prior to expiry of vendor support for both hardware and software and replacing end of vendor support RTUs. This alternative would allow Hydro One to meet the IESO Market Rules for high performance telemetry data. It is cost and time effective to perform both aspects of the investment at the same time because the equipment, engineering and commissioning work are closely related.

E. EXECUTION RISK AND MITIGATION

The major risk associated with the execution of this program is the ability to obtain the project outages necessary for field commissioning. Cancellations may arise due to higher priority projects or unforeseen system contingencies. The strategy for risk mitigation will be to apply for project outages as soon as possible.

GP-03 Network Management System Capital Sustainment

Start Date: Q1 2021		**Priority:**	High
In-Service Date: Q3 2023		**3 Year Test Period Cost ($M):**	30.2
Trigger(s): Immediate/Short-Term Compliance, Preventative Maintenance /System Renewal, Reliability			
Outcomes: Regulatory Compliance, Maintenance of Performance and Reliability			

A. OVERVIEW

The Network Management System ("NMS") is a critical operating tool used to control switching operations and alarm monitoring at Hydro One's control centres; the Ontario Grid Control Centre ("OGCC") and the Back Up Control Centre ("BUCC"). The current NMS application software, server hardware and operating system are forecasted to be out of the vendor support window by 2023. All NMS end of vendor support components require an upgrade before reaching the end of vendor support. This upgrade is necessary to maintain required levels of NMS performance, reliability, availability and regulatory compliance. The projected costs of the project are estimated to be $38.3 million over the 2020-2024 planning period.

B. NEED AND OUTCOME

Investment Need

This investment provides for an upgrade of the NMS, a critical operating tool used for the monitoring and control of the Hydro One transmission system. The NMS system includes the application software and associated licenses, hardware and infrastructure, operating system, databases, and front end processors. The NMS application is used to monitor the status (e.g. open, closed, loading) and condition (e.g. alarm annunciation) of the transmission system and its assets, and to control and operate the assets to change system configuration or restore supply to customers after a contingency from the OGCC and/or the BUCC. This includes the execution of maintenance outage requests by field staff, customers, and the Independent Electricity System Operator ("IESO"). The reliable operation of the Ontario Bulk Electric System ("BES") is dependent on the consistent high availability and reliable performance of the NMS.

Without this investment, the continued high availability, high performance, and security of the NMS would not be assured. Alarms may not annunciate if the NMS system is impeded operationally or rendered unavailable. Failure to clear a fault or isolate a faulted element from the system in a timely manner, could result in a wide spread interruption in the BES due to the cascading effect of protection systems. One example of the potential impact of a delayed response is the 2003 Northeast Blackout, ultimately attributed to control room operation and tool issues.

Upgrades to the NMS are required prior to reaching end of vendor support for the software, hardware components, and operating system to ensure that Hydro One will receive the appropriate level of vendor support including software patches to maintain compliance to North American Electricity Reliability Corporation ("NERC") Cyber Security. The current application software, Alstom Energy Management System ("EMS") version 2.6, server hardware and existing operating system will all be out of the vendor support window in 2023.

Implementation of the NMS upgrade is also triggered to maintain compliance with regulatory standards. These standards are described below:

<u>NERC Reliability Standards</u>

NERC TOP-001-4 R10 and R13, govern the standards for monitoring and frequency of real-time assessments of the transmission system.

<u>IESO Hydro One Operating Agreement</u>

Operational Responsibilities under Part 2 of the IESO Hydro One Operating Agreement, including responsibilities under Section 4.2 govern: the availability and capability of equipment; the connection and disconnection of equipment to the IESO-controlled grid; and actions or recommendations regarding control voltage, loading, and configuration of facilities.

<u>OEB Transmission System Code</u>

OEB Transmission System Code Section 5.4 sets out a transmitter's performance requirements under emergency operations conditions.

NMS alarm monitoring capabilities facilitates situational awareness of changing conditions that may affect operation of the BES. NMS remote operation and control of assets minimize the impacts of an emergency situation. Upgrade of the NMS is required to continue these capabilities.

Investment Description

This investment will upgrade the NMS software and provide additional upgrades to the server operating system, database software and all end of vendor support monitoring and control computers, network and storage hardware. This investment will provide capacity for emerging transmission system requirements, create the opportunity to leverage a new baseline functionality and ensure that the NMS remains a fully vendor supported system.

This project investment has significant customer impacts as it allows for Hydro One control room staff to monitor customer connection status, coordinate customer outage requests, and restore or investigate events impacting customers. The NMS upgrade will also allow Hydro One control room staff to efficiently coordinate system operations and explore improved operating availability.

This investment will maintain required levels of NMS performance, reliability, availability and regulatory compliance by upgrading all NMS end of vendor support components; (i) power system, operating system, database software, and (ii) NMS specific infrastructure hardware for continued sustainability. The project has been scheduled based on information technology lifecycles with consideration of software, operating system, and server hardware lifecycles.

Outcomes

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Allows for Hydro One control room staff to monitor customer connection status, coordinate customer outage requests, and restore/investigate events impacting customers.
Operational Effectiveness	• Allows for Hydro One control room staff to efficiently coordinate system operations. • Enable improved operating availability by allowing Hydro One to have two active control centres.
Public Policy Responsiveness	Allows Hydro One to meet the obligations of: • OEB Transmission System Code (Section 5); • Operational Responsibilities as outlined under Part 2 of the IESO Hydro One Operating Agreement, including responsibilities under Section 4; and • NERC standards, NERC TOP-001-4 R10 and R13
Financial Performance	• Avoid expensive extended support costs for end of vendor support NMS application.

C. EXPENDITURE PLAN

This is a recurring investment. The budgeted cost is based on historical NMS investments and is in line with Hydro One's 2015 NMS upgrade, which cost $38M. The final costs will be determined nearer to the investment date, at which point the products offered and the associated costs will be available. To increase cost estimation accuracy and to reduce project execution risks, the development phase will provide the following deliverables:

- vendor statement of work cost estimates; and
- architecture for the main upgrade environments for more accurate hardware cost estimates.

Final costs of the project will be influenced by any change in available technologies, costs associated with infrastructure support and the market price at time of purchase. Technological uncertainties can be a challenge when forecasting for future capital projects. Hydro One is continuously monitoring technological developments and industry best practices to ensure the most cost effective solution.

The investment schedule was derived by understanding that the existing NMS system will be end of life in 2023 and working backwards on a 3 year implementation schedule.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	0.0	0.0	7.8	22.4	8.2	0.0	0.0	38.3
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**0.0**	**7.8**	**22.4**	**8.2**	**0.0**	**0.0**	**38.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**0.0**	**7.8**	**22.4**	**8.2**	**0.0**	**0.0**	**38.3**

[1] *Includes Overhead at current rates.*

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking:

<u>Alternative 1: Status Quo</u>

This alternative maintains the existing NMS application beyond the end of vendor support. Hydro One rejected this alternative because it would expose the company to reliability and sustainment risk as the current NMS will no longer be supported by the vendor beyond 2023. The lack of vendor support would negatively impact the ability to recover from a system failure. Maintenance costs for extended repairs or replacement components would be higher and more difficult to procure as the technology becomes obsolete. NMS failure would hinder control room monitoring and control capabilities, impeding the operational effectiveness of the OGCC and rendering Hydro One non-compliant with NERC requirements.

The NMS is an essential tool that helps Hydro One meets a number of NERC requirements as a transmission owner/operator. Failure of this system would risk non-compliance with NERC requirements, such as NERC TOP-001-4 R10 and R13. Therefore, this alternative is not recommended.

Alternative 2: New Software Application

This alternative proposes the current system be replaced with a new application from an alternative vendor when the existing NMS application reaches end of vendor support. This alternative has been rejected as Hydro One has many customizations to optimize use of the Alstom EMS suite and therefore cannot switch to another vendor product without significant risk and cost. Integration with other mission critical systems, such as the Control Room Information System, and many years of development of OGCC staff expertise and work processes would be jeopardized. As such, this alternative is not recommended.

Alternative 3: Upgrade NMS Software and pace ancillary upgrades

This alternative proposes upgrading the NMS Software but delaying or pacing upgrades of the accompanying server operating system, database software, and related hardware.
This approach is not advisable because it would require additional testing, labour costs, and outages on the NMS system. The risk on the existing production level system would also be elevated. While Hydro One does maintain redundancy on the NMS system, the redundancy is a requirement of NERC and even the redundant system is subject to availability scrutiny and auditing. There is not enough capacity in the current hardware setup to allow for the rollout of a new NMS application.

Alternative 4: NMS Capital Sustainment Project (*Recommended*)

It is recommended that Hydro One proceed with the NMS replacement to ensure continued system reliability and sustainability. Under this alternative, when the existing NMS has reached end of life in 2023, the NMS will be replaced with the updated version, with expected benefits including functional enhancements and improved technological capabilities. This alternative maintains operational effectiveness and the continued reliability of the daily operating, monitoring and control functions of Hydro One's transmission business. Unlike alternatives 1 and 2, the proposed investment mitigates the risk of control room downtime, interruption of work execution and planned outages that can negatively impact Hydro One customers.

E. EXECUTION RISK AND MITIGATION

To reduce project execution risk, proof of concept NMS console(s) will be designed and tested prior to full deployment, including use of the proof of concept NMS console in parallel with the current system prior to the final transition to the upgraded system. This approach provides for more testing opportunities and allows for non-conformances to be corrected prior to deployment into service. Furthermore, leveraging the lessons learned from the previous NMS upgrade project, completed in 2015, product maturity risk will be minimized by avoiding the installation of a product that is not yet in a production release status. Instead, Hydro One will wait for another utility to first implement the new product and review the project success with that utility to learn from their implementation experience. As a member of the North America Transmission Forum, Hydro One attends meetings and conferences where these experiences are shared.

GP-04 Integrated Voice Communications and Telephony System Refresh

Start Date:	Q1 2021	**Priority:**	High
In-Service Date:	Q4 2023	**3 Year Test Period Cost ($M):**	5.1
Trigger(s): Immediate / Short-Term Compliance			
Outcomes: Minimized Customer Interruption, Prompt Restoration to Normal Operating Conditions, Efficient Communications, Maintenance of Regulatory Compliance			

A. OVERVIEW

The Integrated Voice Communications and Telephony System ("IVCT") Refresh investment is to upgrade the IVCT system software prior to end of vendor support. This is a critical system to the Hydro One transmission network that provides voice communication managements between control centers, field staff, customers, the Independent Electricity System Operator ("IESO") and emergency services. The existing system is custom designed to meet the needs of Hydro One. The software is anticipated to be out of vendor support by 2023. Without vendor support, risks include interrupted voice communications that could delay response times in an emergency or outage restoration. As safety and restoration response times are highly valued and regulated, these drivers trigger the need for this investment. The proposed investment would replace application software and associated phone system hardware at the control centres. The projected costs of the project are estimated to be $6.3 million over the 2020-2024 planning period.

B. NEED AND OUTCOME

Investment Need

This investment replaces the IVCT, which is a critical system that provides voice communication management between the Ontario Grid Control Centre ("OGCC"), Backup Control Centre ("BUCC"), and the IESO, Hydro One field staff, connected customers and emergency services. The IVCT system provides integrated access and intelligent call routing via multiple communication platforms (i.e. mobile satellite phone, Iridium satellite phone, mobile radio) that efficiently manage thousands of daily control room calls.

The IVCT system ensures continued public policy responsiveness by allowing Hydro One to comply with various regulations. These include North American Electric Reliability Corporation ("NERC") communication standards (COM-001-3) and multiple IESO Market Rules that require redundant voice communications, and emergency communications that ensure constant communications paths, as outlined in the Outcome Summary table below.

The end of vendor support for this software is a key date, and the IVCT software will require upgrading prior to becoming unsupported. Although there is currently no announced end-of-support for components of the IVCT, based on forecasted vendor support schedules and hardware lifecycles, the IVCT system will likely require replacement by 2023.

The IVCT is based on commodity hardware provided by CISCO. This includes network-related devices and general purpose computing devices (servers). Typically, these systems have a lifespan of five years, but Hydro One has been successful in extending the life of similar assets in other areas such as the Network Management System, to about seven to eight years by strategic sparing of components, however the software in the system must remain vendor-supported. As new technologies are developed, support for older versions and the ability to purchase spare or replacement hardware becomes more difficult and costly. Also, supporting software products beyond their lifecycle poses increased risk to operations.

The IVCT is a core communication tool for the control room. On average, 2,582 calls are processed through the IVCT per day. Backup emergency communication systems are insufficient to perform regular management of planned activities. A loss of voice communication between the OGCC staff and field staff, the IESO, and Hydro One customers, could result in a negative impact on: wide-spread reliability; finance for Hydro One and its customers; restoration of power after a contingency or planned outage; public and employee safety and the execution of planned outages and work activities; and effective operation of the BES in Ontario.

The IVCT is custom designed to meet Hydro One's Governance and Compliance requirements ("NERC CIPv5") and to be auditable to NERC CIPv5 mandates. These and other unique and custom designed elements include the following:

- The IVCT provides a backup system that is completely separate in terms of physical location, hardware and software across all levels;
- The IVCT has as an operational uptime of 99.99% per year;
- The IVCT is capable of planned or unplanned operational failover between primary and secondary systems at each site;
- PSTN Interface: Public Switched Telephone Network ("PSTN") represents the primary means by which Hydro One field staff, customers and organizations such as the IESO contact Hydro One. Time sensitive, safety sensitive, and mission critical communications require that the PSTN interface be reliable, appropriately sized, and capable of delivering the connectivity required to perform the OGCC mandate;
- Incoming Call Management: The IVCT is responsible for answering and directing all inbound communications to the OGCC, BUCC, or other locations as required. In this role, it assures that callers reach the correct grid operating function in a timely and efficient manner via IVR, and allows System Operating Division ("SOD") staff to prioritize and manage their workload based on the information input by callers;
- Media Voice Prompts: The IVCT System provides navigation instructions for incoming callers through system media prompts;

- Emergency Calls - Inbound: Callers are able to identify their call as an emergency that is placed as priority to be immediately processed by OGCC Dispatchers and Controllers;
- Call Recording: The IVCT is responsible for recording all voice communications traffic, including telephone and radio communications;
- Contact Management ("Rolodex"): The IVCT Rolodex provides users with a rapid interface for making calls via a touch screen interface, and plays an essential role in improving operator efficiency due to the large number of contacts that are required to interact with daily;
- Control Room Site Maps: Provides a visual representation of control room layout, with IVCT consoles, as well as sector queues, displayed as clickable targets for softphone features such as calling and call-forwarding;
- Site In-Out Logging: Site In-Out Logging is a Hydro One policy that tracks the arrival, onsite, and departure status of visitors to stations and restricted areas in situations where they are onsite but do not require interaction with Control Room staff. Upon arrival at a station, visitors are able to register their entry via the toll free IVR system, obtain confirmation that they have logged in at the correct station, and leave a call back number. Similarly, on departure from a station, visitors again call the toll free number, and via the IVR log out of a site;
- Reporting: The IVCT provides a facility for the creation of reports based on activity and audit logging; and
- Outbound Autodialer: The IVCT Autodialer performs five different types of callouts: Planned Maintenance Outages, Planned Outage Cancellation, Verification of Fixes, Informational, and Estimated Time of Resolution. However, the IVCT also allows custom callouts and ad hoc campaign workflows. The Autodialer has the ability to accept and process voice prompts from the customer and update Hydro One systems based on those voice prompts.

These custom elements illustrate the need to maintain the existing IVCT system. If replaced with a generic system, in order to serve the same purpose, external processes would be required to recreate these functionalities and a means to integrate the IVR system would need to be designed, requiring substantial investments of time and money. These factors and others make IVCT utilization beyond vendor-supported lifecycles untenable.

EB-2017-0049, ISD GP-23 describes the distribution portion of this investment.

Investment Description

Hydro One currently has two control centres: the OGCC and the BUCC. The IVCT is a critical system that provides voice communication management between the OGCC and BUCC, the IESO, Hydro One field staff, connected customers and emergency services. The IVCT system provides integrated access and intelligent call routing via multiple communication platforms and is used on a continuous (24/7) basis at both sites as well as within the Operating Planning department.

A failure of the IVCT system will impact work execution, customer outages, responsiveness, and the ability to effectively dispatch for emergencies. Due to the critical nature of the IVCT system and the impact of a failure on daily operations, this system is planned to be replaced based on forecasted vendor lifecycle schedules. Furthermore, failure of the IVCT system would severely curtail the ability to monitor and mitigate system events, leading to negative impacts on customer satisfaction and operational effectiveness.

This investment will upgrade the application software, and associated phone system hardware at the OGCC and BUCC which will be relocated to the Integrated System Operating Centre ("ISOC") when it is completed in 2021. This investment is scheduled in consideration of the vendor's forecasted software and server hardware lifecycles.

Outcomes

This investment will ensure reliability of the IVCT system, which enables efficiency in daily control room operations, minimizes customer interruption, and supports prompt restoration of power equipment, while meeting regulatory requirements. The current features of the IVCT system include a user-friendly touchscreen interface, quick dial functionalities, and a customized rolodex contact database, which will be preserved. Additional features to help controllers do their job more efficiently will be available with the new system, such as automated voice-to-text capability. The IVCT will allow Hydro One to continue to meet its obligations under the IESO Market Rules and NERC.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• This investment helps to ensure a timely and efficient response to failures, unplanned outages, or imminent risks to the transmission system to minimize customer interruption and prompt restoration to normal operating conditions. Customer engagement has indicated that most transmissions customers value prompt restoration as "extremely important". • Supports system reliability by maintaining a communication medium between control room and customers. • A low call-handling time minimizes the impact of business interruptions and enhances customer experience.
Operational Effectiveness	• Supports system reliability by maintaining a communication medium between the control room and field staff. • Allows OGCC and BUCC staff to more efficiently coordinate maintenance work, and system events with LDCs, generators and customers on the transmission system.

Public Policy Responsiveness	• Allows Hydro One to meet Market Rules, including, but not limited to:
	    o Chapter 2, Appendix 2.2, Section 1.1.4
	    o Chapter 2, Appendix 2.2, Section 1.2.3
	    o Chapter 5, Section 12.1.1
	    o Chapter 5, Section 12.1.6 & Section 12.2.12
	    o Chapter 5, Section 12.2.3
	    o Chapter 5, Section 12.2.4
	    o Chapter 5, Section 12.2.11
	    o Chapter 5, Section 12.3.2
	• Allows Hydro One to meet NERC-COM-001-3.
	• Allows Hydro One to meet NERC CIPv5
	• Allows Hydro One to meet Transmission System Code, section 10.1.

Financial Performance	• Promotes efficient communications to minimize restoration times during planned and unscheduled events.

C. EXPENDITURE PLAN

Costs have been determined based on estimates utilizing historical IVCT investments. Based on lessons learned from previous IVCT projects, this proposed budget takes into consideration all relevant costs (i.e. license fees, interest/overhead, and other miscellaneous charges). The best available predictor of the technology costs are past costs and performance. It is not possible to predict, with much certainty, what products will be available and at what cost, this early in the planning horizon. Utilization of a more refined estimate method to determine cost will result in estimates that will no longer be relevant for a project with a start date of 2021.

The OM&A cost for the current IVCT system is approximately $0.7M annually. Hydro One will strive to reduce these costs with the new IVCT system.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	0.0	0.0	1.9	3.2	1.1	0.0	0.0	6.3
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**0.0**	**1.9**	**3.2**	**1.1**	**0.0**	**0.0**	**6.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**0.0**	**1.9**	**3.2**	**1.1**	**0.0**	**0.0**	**6.3**

[1] *Includes Overhead at current rates.*

D. ALTERNATIVES

<u>Alternative 1: Status Quo</u>

This alternative maintains the existing IVCT system beyond end of vendor support for the software and hardware. Hydro One has been successful in extending the life of similar assets in other areas by strategic sparing of components, as long as the software in the system remains vendor-supported. Even if the hardware has become obsolete, as long as the software remains supported, the equipment can continue to be used with minimal risk, as software fixes can be obtained from the vendor, and hardware can be replaced by drawing down spares. There is the potential to negotiate extended support arrangements (at additional OM&A cost) with the vendor for some of the IVCT software, but the software associated with the hardware is typically tied to the end of vendor support of the hardware itself. Hence the need to upgrade by this time a**s** this will expose Hydro One to reliability risk as the current IVCT system will no longer be supported by the vendor. In addition, the ability to recover from a system failure will be negatively impacted and extended repairs or replacement components will pose higher maintenance costs and be more difficult to procure.

A failure of the IVCT system will interrupt control room communication efforts, impede the operational effectiveness of the OGCC or the BUCC and could render Hydro One non-compliant with various NERC and Market Rules requirements. Therefore, this alternative has been rejected.

<u>Alternative 2: Replacement with an Off-the-Shelf Generic Phone System</u>

This alternative proposes that the current system be replaced with generic phones after the existing IVCT system reaches end-of-life. A generic phone system does not have the required functionality for control room operations such as a "rolodex of frequent calls", call recording capabilities to meet NERC compliance requirements, and an Interactive Voice Response ("IVR") system to direct and prioritize incoming calls. For the same functionality, external processes must be recreated for this alternative and a means to integrate the IVR system must be designed.

Due to the aforementioned issues and concerns, and the inability of this alternative to provide the needed functionality and integration with key elements, such as IVR, this alternative has been rejected.

Alternative 3: IVCT System Refresh (*Recommended*)

It is recommended that Hydro One proceed with a similar IVCT system replacement to ensure continued system reliability and sustainability. This alternative plans for the IVCT system replacement starting in 2021, leveraging newer technologies when the existing IVCT system has reached end-of-life. Hydro One is not currently aware of an announced end-of-support for any component in IVCT. End-of-support announcements are not always made sufficiently in advance to support a five-year planning cycle. Past experience must therefore inform the anticipation of this investment need. To meet the forecasted end-of-life and in-service target in 2023, the project must start in 2021. This will maintain the operational effectiveness and reliability of the OGCC and BUCC by maintaining these critical communication channels. This will also mitigate the risk of control room downtime, work execution delays, planned outage cancellations and the resulting negative impacts on Hydro One customers that these incidents cause.

E. EXECUTION RISK AND MITIGATION

Prior to the full deployment of the new IVCT system and to reduce project execution risk, a pilot IVCT system will be designed, installed and tested in parallel with the existing system. An experienced system integrator, with expertise in deploying similar IVCT systems, will be retained to oversee the project.

Functional enhancements and new technologies, such as automated voice-to-text capability, will be individually evaluated through a cost-benefit analysis closer to the project start date to ensure that value to customers can be demonstrated. Timing of this review is required prior to project commencement, as technologies and improved functionality today may have evolved significantly by 2021.

GP-05 Transmission Non-Operational Data Management System

Start Date:	Q2 2020	**Priority:**	High
In-Service Date:	Q4 2024	**3 Year Test Period Cost ($M):**	15.9
Trigger(s): Immediate/Short-Term Compliance, Productivity, Strategic, Corrective Maintenance, Preventative Maintenance			
Outcomes: Automatic collection and real-time processing and archiving of Non-Operational data, Condition-Based Maintenance			

A. OVERVIEW

The Transmission Non-Operational Data Management System project will leverage the capabilities of existing technology by connecting existing monitoring devices to a centralized and integrated data management system. Data will be collected centrally and used for monitoring, reporting and analysis. The project consists of hardware and engineering development at the substation level to ensure interfacing of all substation devices and components and the collection and processing of non-operational data. Software and hardware integration at the Central/Enterprise level will also be required to ensure processing and archiving of all substation non-operational data, and to connect, interface and exchange data with external programs which will facilitate analytics, reporting and visualization. A pilot project has been developed and is underway which will assess the most effective implementation of the project moving forward. Based on this pilot project, a data acquisition and management system ("the system") will be chosen or developed.

This project provides the necessary framework to enable the automation and use of enhanced technology to realize costs reductions related to maintenance activities and dispatching field personnel, perform condition-based maintenance, and provide access to detailed and accurate information to be used in analysis and modeling. The system also provides an essential foundation to pursue future initiatives and provide system controllers with additional operational awareness, allowing for proactive control actions to avoid equipment failure and minimize customer impacts. The Non-Operational Data

Management System will build on and enhance Asset Analytics ("AA") accuracy and dependability by including previously unavailable monitoring device data in the asset risk modeling.

B. NEED AND OUTCOME

Investment Need

In an effort to reduce OM&A costs, Hydro One is embarking on an initiative to implement a Transmission Non-Operational Data Management System. Non-operational data is defined as data, in a variety of formats, generated during the operation of the transmission and distribution grid that is not continually utilized by the Ontario Grid Control Centre ("OGCC") for real-time operating processes. While this data is not required for the real-time operations of the Hydro One transmission system, the collection of this data will provide the platform to empower various lines of business to pursue efficiencies and streamline business processes, such as moving from time based maintenance to maintenance based on condition which will result in OM&A savings as well as increase in reliability by minimizing the possibility of catastrophic asset failure. This data can also be utilized to support or supplement real-time operating processes and decisions.

Figure 1 depicts a conceptual diagram of the envisioned Transmission Non-Operational Data Management System.

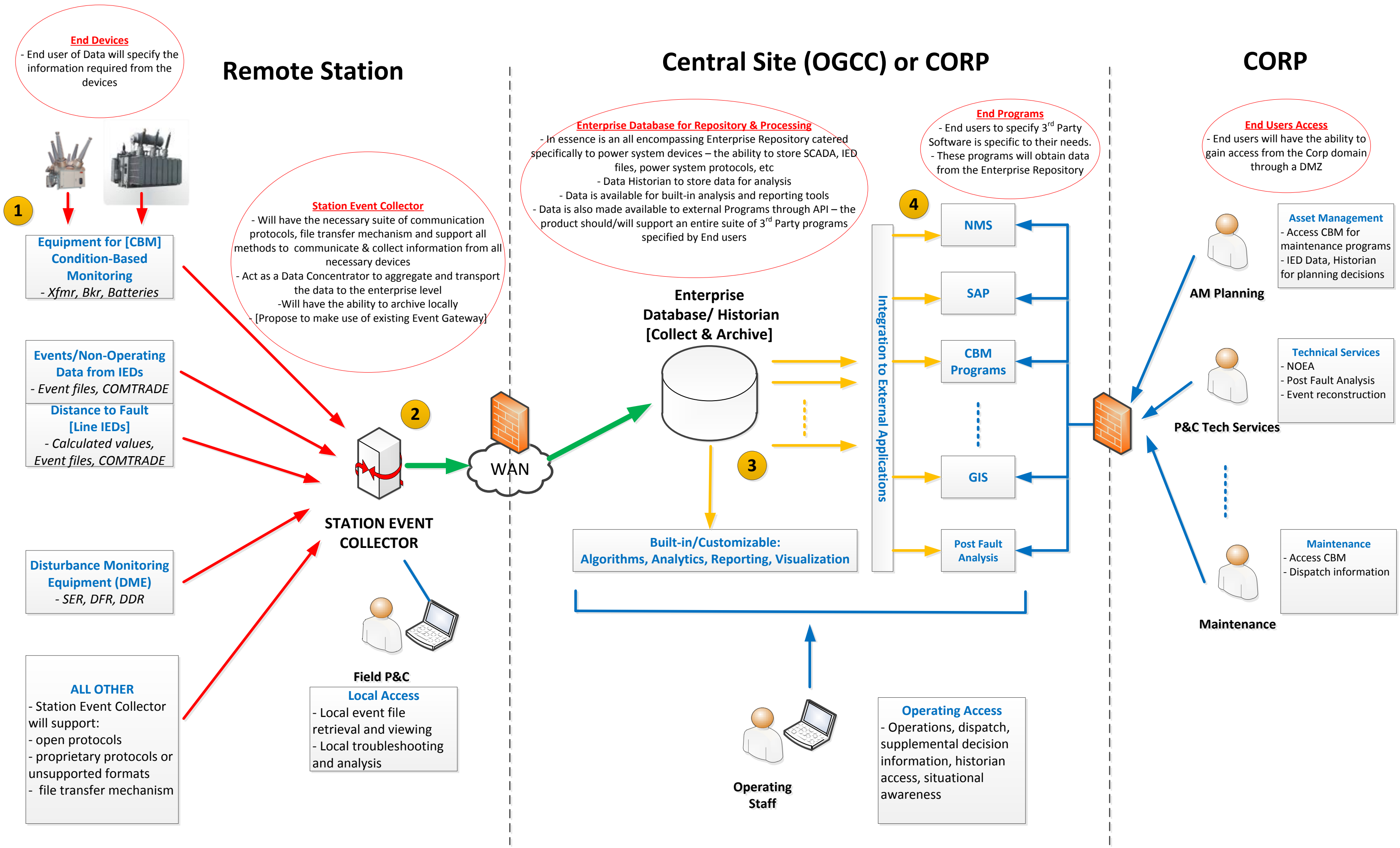


Figure 1 - Transmission Non-Operational Data Management System

There are essentially four sub-components which collectively make up the system:

1. Remote Station Collection: The Remote Station Collection are end devices that act as data sources for the Station Event Collector.
2. Station Event Collector: The Station Event Collector is a data concentrator for non-operational data coming from various end devices. It will be required to support the necessary suite of communication protocols, file transfer mechanisms and support all methods to communicate and collect information. As a data concentrator, it will be required to aggregate and transport the data to the Database/Historian at the Enterprise level.
3. Enterprise Database/Historian: The Enterprise Database/Historian will collect and archive all non-operational data from the various "enabled" substations. It will have the ability to create customized dashboards, perform analytics, generate reports, annunciations, trending, and will include alerting capabilities via methods such as alarms and emails.
4. Interface: The interface will allow the data from the Database/Historian to connect with external applications to enable users across the corporation to effectively access and utilize the data.

This initiative provides the necessary framework to enable automation and use of enhanced technology to realize cost reductions related to maintenance activities and personnel dispatch. The system also provides an essential foundation to pursue future initiatives.

The assets to be monitored will include, but are not limited to: transformers, breakers, capacitors, reactors, batteries, Intelligent Electronic Devices ("IEDs") such as protection relays, buildings, cables and lines. Examples of data that will be collected and aggregated in the system include:

- For Breakers: I^2T (a measure of energy dissipation), duty cycles, number of operations, and other measures of mechanical health;

- For Transformers: Gas measurements, bushing conditions, partial-discharge measurements, temperatures and tap-changer movements;
- For Lines: Distance to fault calculations; and
- For Disturbance monitoring: Sequence of Events, digital fault and waveforms and dynamic response measurements.

The availability of this additional information will make Hydro One processes more efficient and effective and will aid in: real-time operating decisions, life cycle management decisions for power system assets, and post fault analysis and event reconstruction efforts.

The deployment of the Transmission Non-Operational Data Management System will allow Hydro One to realize the following benefits:

<u>Condition-Based Maintenance ("CBM"):</u> Currently, Hydro One's maintenance activities for station assets are completed at pre-determined time intervals or are performed reactively. In contrast, a CBM approach monitors the current condition of the assets to gauge when maintenance activities are necessary. Information collected through the monitoring process, such as indications of deteriorating performance, are used to determine the frequency and specific type of maintenance activities that are required. This strategy optimizes station maintenance resources and activities. Cost savings are expected to be realized in the form of reduced maintenance activities, less frequent dispatching of staff for manual data sampling and retrieval, and fewer unplanned activities.

The predictive approach, incorporating non-operational data and analysis, will allow assets to be operated beyond their estimated service life if the data being collected supports continued use. This will result in an increased useful life of assets and optimized performance outputs.

Automated Non-Operational Data Collection from Substation Devices: Currently, the protection IEDs serve only two purposes: power system protection and reporting of real-time operating information. However, these devices have the capability to provide additional non-operational data through sensing and calculating functions. Programming the IEDs to collect this information and having the ability to access data remotely such as: Distance to Fault data and system logs for post-fault analysis would provide savings by eliminating manual processes and the need to dispatch personnel and would improve employee safety by reducing road time.

For example: Distance to Fault data can be used to dispatch line crews to the approximate fault location with a higher degree of accuracy. This will provide savings by reducing resource intensive inspections and patrols, performed via airborne helicopter fly-by inspection or ground based visual line inspection. Similarly, when a disturbance on the power system occurs, system data needs to be collected for proper fault analysis, a process which currently requires the dispatch of field personnel for manual data collection. Automating this collection method would enable savings by eliminating the need to dispatch personnel and improve employee safety by reducing travel to stations some of which are quite remote.

Averting Catastrophic Failure: A non-operational data management system, as proposed, is expected to deliver financial and labour efficiencies stemming from averting serious power system failures, which would have resulted in environmental impacts and extended customer outages. For example: several utilities (i.e. Alectra, PG&E and AEP) have been able to avert major transformer failures with the use of non-operation data. The transformer monitoring provided a warning that the transformer was about to fail. The utilities were able to preemptively remove the transformer from service prior to failure, resulting in cost savings in damages and mitigating outage impact to customers.

In another example, the oil of a 75/125 MVA 230 kV-27.6 kV transformer was monitored for gassing vs. load and oil temperature. The monitoring provided an indication of increased transformer gassing, which is a signal of potential impending failure. The utility was able to preemptively react and repair a manufacturing defect in the transformer at a cost of $100,000, averting up to $2 million in damages if the unit had failed catastrophically or with serious internal damage to the windings or core.

AEP also provided three examples in just two years (between 2014 and 2016) in which transformer failure was averted due to operating action taken after analyzing non-operational data. In each case, measurements indicated issues with the transformer and the transformer was taken out of service while manual testing was performed to confirm the indications. When the results were confirmed further testing was conducted to assess whether the unit could be repaired or replaced. In each case, the online measurement indications provided sufficient warning to take the transformer out of service prior to failure, avoiding significant costs and damage in each event.

A significant portion of the cost for this investment could be offset by the avoidance of a single major disaster such as a transformer explosion. The cost of the replacement transformer itself may be up to $1 million, while costs of environmental clean-up, reputational damage, labour required to remove the destroyed transformer and install the new transformer, associated extended outages and possible damage to the station surroundings would also be significant. The total expected cost associated with a single transformer explosion could easily amount to several million dollars.

Regulatory Compliance:

A Non-Operational Data Management System will support compliance with NERC PRC-005-6 *Protection System, Automatic Reclosing, and Sudden Pressure Relay Maintenance* in relation to station battery maintenance through the use of battery monitors to allow for reduced visual time based maintenance as battery monitoring would be real-time.

Hydro One uses two types of station batteries: Vented Lead-Acid ("VLA") and Valve-Regulated Lead-Acid ("VLRA"). All batteries associated with components of a protection system DC supply that are Vented Lead-Acid Batteries or Valve-Regulated Lead-Acid Batteries require time-based maintenance programs within certain specified maximum maintenance intervals according to Table 1-4(a) and Table 1-4(b), of NERC PRC-005-6.

However, the specified time-based maintenance activities for NERC compliance can be completely eliminated if adequate remote monitoring of this data (non-operational in nature) is in place. Certain monitoring functions may be used in lieu of periodic maintenance, as specified in Table 1-4(f) of NERC PRC-005-6. Monitoring functions that may eliminate the need for periodic maintenance include monitoring and alarming of the battery charger voltage to detect charger overvoltage and failure, electrolyte level monitoring and alarming, unintentional dc ground monitoring and alarming, and monitoring and alarming of battery string continuity, among others. By requiring a specified set of non-operational data to be monitored and alerts to be provided based on specific criteria, this standard allows for the elimination of station battery maintenance. Effective implementation of the Non-Operational Data Management System to provide monitoring and alerts based on these criteria will eliminate the need for field personnel to provide regular on-site inspections, will result in a more comprehensive understanding of battery condition, and will provide a more efficient means of NERC compliance. Cost analysis performed for battery maintenance (specific for NERC PRC-005-6 compliance) determined that installing online monitors on NERC impacted sites will generate an estimated cost savings of $760,500 per year.

<u>Foundation for Future Initiatives</u>: The Non-Operational Data Management System will also provide an essential foundation for future initiatives. Once developed, this infrastructure will allow for additional metrics and models to be implemented to assist in better decision-making by using a predictive approach for maintenance planning resulting

in improved levels of asset performance. For example, when the system is first implemented, distance to fault data will be assessed based on calculated IED values applicable only to permanent faults for radial lines. In the future, additional models could be implemented in order to calculate multi-ended lines, transient faults, correlations with weather / lightning data, and other scenarios. Another example is the opportunity to augment and enhance the capability of AA, currently used by planners for assessment of asset condition. The use of non-operational data can be used to model asset condition with increased accuracy.

This project is assigned a high level priority since it will result in OM&A savings and efficiencies related to labour and processes. The movement towards a CBM approach is in line with the regulator's expectation of managing and replacing assets based on actual condition rather than age.

Investment Description

The investment scope includes the development and implementation of several components, which are expected to be executed in parallel. Hardware and engineering development will be required at the substation level to ensure interfacing of all substation devices and components and the collection and processing of non-operational data.

The Database/Historian component will reside at the Central/Enterprise level where all data is aggregated, rather than at the Operations level where typical power system work occurs. This will permit the data to be accessed across the corporation, but will also require certain steps to be taken at the Central/Enterprise level.

- Software and hardware integration at the Central/Enterprise level will be required to ensure processing and archiving of all substation non-operational data. Installation of addition software/hardware is anticipated.
- Software and hardware integration at the Central/Enterprise level to connect, interface and exchange data with external programs which will facilitate analytics,

reporting and visualization. This will enable several Lines of Business ("LOB") to make practical use of the collected data to realize efficiencies and make better decisions for the maintenance and management of transmission system assets. Installation of addition software/hardware is anticipated.

The implementation plan will involve a staged approach. Criteria will be established to prioritize which processes would benefit most from the automatic collection and analysis of non-operational data. In prioritizing and pacing the implementation of this system, the following factors will be considered:

- Stations in which station battery maintenance is performed for NERC PRC-005-6 compliance will be prioritized, as implementation of this project will completely eliminate the need for maintenance on these systems.
- Stations will also be prioritized where:
    - DME equipment is already in place;
    - many equipment sensors are already installed; and/or
    - there is high spending on power system equipment maintenance.
- The overall plan will be to implement the system at as many stations as possible.

The decision for recommending the proposed alternative is based on the delivery of cost savings for process and personnel efficiencies as well as allowing Hydro One to realize a CBM approach to maintain and manage power system assets. Currently, approximately $900,000 is spent yearly on dispatching field personnel to retrieve non-operational data. The goal is to reduce this expense as much as possible. The ultimate savings due to implementation will depend on what issues will arise, at what frequency, and at which stations.

Outcomes

The following table presents anticipated benefits of the investment in accordance with the Ontario Energy Board's ("OEB") Renewed Regulatory Framework ("RRF"):

Customer Focus	• Improvements to reliability are expected as other utilities which have implemented a similar Non-Operational Data Management System have prevented catastrophic failure of power system equipment such as transformers, thereby avoiding potential lengthy outages.
Operational Effectiveness	• Access to non-operational data will offer additional insight into power system assets condition, which will facilitate a more proactive approach to CBM resulting in improved reliability and a reduction in the cost of maintenance and asset failures. This will also result in improvements in SAIDI and reduction in OM&A as remote access to station data will eliminate the need to dispatch personnel during line fault events.
Financial Performance	• Cost savings are expected to be realized by shifting from time-based maintenance to condition-based maintenance, as well as through the efficiencies of minimizing or eliminating manual processes.

C. EXPENDITURE PLAN

The estimated costs have been assessed on a preliminary basis and will be revised according to the final assessed need. The ultimate cost of the project will depend on several factors:

- An evaluation of whether existing corporate systems meet the functional requirements or if a new system is required to be implemented. Accordingly, there may be additional upfront costs to facilitate new hardware, software, and licensing.
- Each substation currently has different levels and vintages of devices. The total project costs will be impacted by the extent of data integration required at each station and the requirement of installation of any additional remote sensing devices.
- Additional software packages may need to be purchased if evaluation deems it more cost effective than developing in-house algorithms. Potential costs associated with the purchase of software packages or the labour efforts required to develop in-house algorithms will be assessed if and when a need for new software is assessed.

Since the Non-Operational Data Management System will provide the foundation for future initiatives, there may be additional feature enhancements, modifications, or rectification required as future initiatives are implemented. The primary focus of this project is to build the foundation for the system and integrate as many substations as possible into the system. Future initiatives will be funded at a later time or through additional funding.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	0.0	5.2	5.3	5.4	5.5	1.1	0.0	22.6
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**5.2**	**5.3**	**5.4**	**5.5**	**1.1**	**0.0**	**22.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**5.2**	**5.3**	**5.4**	**5.5**	**1.1**	**0.0**	**22.6**

[1] *Includes overhead at current rates.*

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking:

<u>Alternative 1: Status Quo</u>

Alternative 1 is to continue with time-based maintenance schedules and manual collection of substation non-operational data. This alternative has been ruled out, as this solution is less efficient and more expensive in the long run than the alternatives.

<u>Alternative 2: Improve Existing Systems</u>

Alternative 2 is to make improvements to existing non-operational systems which are segregated in nature. The current system was developed without anticipating the potential to develop CBM or system integration. Automation of some of the non-operational systems is possible but the remainder will still require either manual intervention or personnel dispatch to retrieve data due to limitations of the existing technology. This alternative has been ruled out, since the existing systems do not have the archival, analytic or integration capabilities for systems which would properly facilitate the CBM approach and enable remote access of data collected at the stations.

Alternative 3: Full Implementation of Non-Operational Data Management System (Recommended)

This alternative includes the full implementation and development of a Non-Operational Data Management System. The implementation and development program will include Remote Station Collection, Station Event Collector, Enterprise Database/Historian and a component of integrating the system.

This alternative allows Hydro One to realize a full CBM approach to maintaining and managing transmission system assets and allows remote access of data collected from devices at the station. This alternative has been recommended since it will deliver cost savings stemming from process and labour efficiency gains and it aligns with RRF outcomes as demonstrated in the outcome summary above.

E. EXECUTION RISK AND MITIGATION

A potential risk affecting the delivery and completion time of this project is the difficulty in integrating several different data systems into one common data management system, due to interoperability challenges. Hydro One will mitigate the integration risks by limiting the initial roll out to a pilot site(s) and applying the lessons learned through that process to the broader roll out that follows. A pilot project has been developed which will determine the implementation path going forward. From 2020 onward, the final project will be implemented and rolled out.

GP-06 Operating Common Information Technology Infrastructure

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Q4 2024	**3 Year Test Period Cost ($M):**	6.4
Trigger(s): Immediate/Short-Term Compliance			
Outcomes: Continued support for key customer applications, maintained IT facilities supporting critical grid operations, maintained compliance with regulatory requirements, cost effective management of IT lifecycles, and improved asset performance			

A. OVERVIEW

This investment involves the systematic replacement of common Information Technology ("IT") infrastructure for the Hydro One critical network operating systems used to facilitate business operations. Hydro One adheres to an IT industry standard practice of managing its assets through a lifecycle program in order to ensure vendor support continues to be available and the likelihood of failure is minimized. This investment is driven by the need to maintain current reliability and service levels with the continued support of mission critical applications in order to serve Hydro One customers in the most cost effective manner possible while maintaining compliance. While a number of factors may drive product replacement, product lifecycles and available support agreements established by vendors are the major determining factors for product replacement. The investment will result in continued support for key customer applications, maintenance of the required IT facilities to support critical grid operations, maintained compliance with regulatory requirements with regards to cyber security and reliability, cost effective management of IT lifecycles, and improved asset performance. The projected costs of the project are estimated to be $12.0 million over the 2020-2024 planning period.

B. NEED AND OUTCOME

Investment Need

This investment will sustain the IT common infrastructure which is the shared platform for the Hydro One critical network operating Enterprise Information Systems ("EIS"). EIS is the combined hardware and software IT system(s) used to facilitate business operations. The use of a shared IT platform used by multiple systems is technically more efficient and maintains a lower total cost of ownership as compared to multiple discrete instances to support specific systems. This translates into less sustainment and total system component purchases.

However, failure of any individual component has the potential to cause cascading system impacts including the failure of critical applications and the business functions they support, removal of system redundancy, and the possible unavailability of the Ontario Grid Control Centre ("OGCC") and/or computer systems. Resulting impacts on customers and work execution may include:

- Cancellation or delay of outages involving planned field work, causing customer inconvenience, and work delays, rescheduling, reprioritization and rework;
- Unresponsive outage management, lack of communication with customers and staff, safety risks, and an inability to respond to emergency events; and
- Backup activation which limits full business function and hinders critical response.

The common IT infrastructure consists of many subcategories of both hardware and software. The lifecycles for different IT product are influenced by a number of factors, including North American Electric Reliability Corporation ("NERC") security patch standard compliance, market performance of current products as evaluated against competitive products, technology innovation and development and the drive to replace existing products as they mature and are supplanted by newer and functionally superior technologies. As new technologies are developed, support and the ability to purchase spares or replacements for previous versions become more costly and difficult to source. Extended support agreements may be available for certain products at the end of their vendor support window, but historically, the extended support costs are significantly more expensive than standard market products. Product replacement parts also become scarce and inflated in price outside the vendor support window and there is an increased risk of non-compatibility with more current devices. Furthermore, supporting products beyond their vendor assessed lifecycle poses increased risk to operations. Loss of vendor support means potential security vulnerabilities are not addressed creating non-compliance, the potential for reduced availability of parts, and increased complexity when the system requires upgrading.

These factors and others make utilization of products beyond their lifecycles untenable. Each device is interdependent and future replacement technology attributes are almost always unknown, pacing and prioritizing is a continuous effort. The process of assessing device compatibility at the end of its lifecycle requires careful architectural consideration to ensure that system reliability and performance standards are consistently being met.

Investment Description

This investment is comprised of multiple asset groupings, and is required to maintain the viability of the common IT infrastructure for Hydro One network operating computer applications. These include the Network Outage Management System, Network Management System, Outage Response Management System, and Distribution Management System. These applications are leveraged by both Transmission and Distribution at both the OGCC and the Back-up Control Centre (“BUCC”). However this investment represents the Transmission portion exclusively. Hydro One has used the approved Black & Veatch Common Asset Allocation methodology in order to allocate the costs between Transmission and Distribution.

The common IT infrastructure consists of both hardware and software and is further defined into subcategories, which include:

- Data storage (devices that retain, retrieve and archive digital computer data);
- Computer servers (processors that fetch, decode, execute and write data in response to system processes and inquiries);
- Computer consoles (used by control room staff to interface with applications);
- IT networks (a series of communication paths interconnecting devices); and,
- Operating Systems/Applications/Software (i.e. VMware, a virtualization of servers/desktops), Citrix (presentation software), Windows Server and Desktop operating system.

Each of the above subcategories can include hundreds of individual hardware and software products and/or assets. The lifecycle of the various components are dynamic, and can at times be interdependent, influencing other components. The hardware is generally problem-free, however lifecycle management means keeping it in a supportable state as dictated by the vendor.

Hardware lifecycle is an ongoing evaluation for all current and future IT investments. All devices are current to the year they were "*lifecycled*" (when they were last replaced or updated) and there is no single project that replaces everything at the same time in any given year. Therefore, the equipment age distribution will always vary. Lifecycle planning forecasts in each category have leveraged historical trends, however, careful consideration regarding the lifecycle replacement and transferability of the infrastructure will be determined as Hydro One moves to the Integrated System Operations Centre ("ISOC") (described in ISD GP-01) beyond 2021. Considerations of the relocation of assets to the proposed ISOC facility may influence decisions on the timing and implementation of certain asset renewals, including data storage, compute servers, computer consoles, IT networks and operating systems/applications/software.

Outcomes

These investments will provide cost conscious ongoing product support and dynamic lifecycle management for all common IT infrastructure assets.

The following table summarizes the anticipated benefits as a result of this project:

Customer Focus	• Provides continued support to key customer applications such as the Network Outage Management System and the Network Management System, which support emergency storm response, communication, and outage coordination. • Minimizes customer risk and associated impacts of system outages.
Operational Effectiveness	• Provides the required IT facilities to holistically support mission critical grid operations, applications, systems, and their functions. • Decreases risk of reduced performance, or an inability to meet service levels in the event of a failure.
Public Policy Responsiveness	• Ensures mission critical grid operations, applications, and systems are supported with the current, compatible and supported IT infrastructure to maintain reliability and availability targets and meet regulatory requirements with regards to cyber security and reliability.
Financial Performance	• Provides cost effective management of IT lifecycles with current and supported common IT infrastructure. • Reduces OM&A expenditures and negates the need for costly extended support. • Improves asset performance, and the ability to recover from a failure. Grid failure can impose significant costs from the disruption to business function operational, increased labour cost for emergency break fix needs and other remedial efforts. These systems are used by Operating to monitor and control the Bulk Electric System and to manage planned and unplanned outage work in a proactive way.

C. EXPENDITURE PLAN

This group of investments is estimated based on historical costs, subject matter and industry expert input, and ongoing assessment. The cost estimate will be adjusted for the project scope, local condition and market pricing at the time of the investment.

Controllable costs have been minimized through the continued use and shared costs of common platforms, maximizing space, storage, and networking; maintaining current versions/latest technologies to maintain or reduce OM&A costs; and bundling of work to minimize outages or impacts to grid operations. Competing technologies are evaluated based on cost analysis and overall, the common IT platform requires less maintenance effort and a lower cost of acquisition as compared to multiple discrete components.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	1.7	0.8	2.0	3.7	3.3	2.2	0.0	13.7
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**1.7**	**0.8**	**2.0**	**3.7**	**3.3**	**2.2**	**0.0**	**13.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.7**	**0.8**	**2.0**	**3.7**	**3.3**	**2.2**	**0.0**	**13.7**

[1]*Includes Overhead at current rates.*

D. ALTERNATIVES

Alternative 1: Status Quo

This alternative is to maintain status quo: do nothing and continue to use the existing IT infrastructure. As each device represents an important interconnected component of the common IT infrastructure, not proceeding with these lifecycle replacements could result in the following:

- A diminished capacity to serve and to meet customers' expectations;
- Regulatory non-compliance with potential financial penalties;
- Possible loss of one or more mission critical applications;
- Significant increase in system maintenance costs;
- Loss of the original equipment manufacturer/vendor support;
- Increased likelihood of system failures, and an inability to recover from these;
- Increased system security vulnerability to cyber-attacks;
- Potential to strand future application upgrades and enhancements; and
- Risk of higher cost of remedial efforts in the event of a failure.

Alternative 2: Maintain Supported IT Infrastructure (Recommended)

Lifecycle infrastructure management, based on industry best practices and vendor support schedules, ensures the continued viable operation of common IT infrastructure assets. There are a number of factors that drive hardware refresh – vendor supportability being a primary driver. Hydro One adheres to an IT industry standard practice of managing its assets through a lifecycle program ensuring vendor support is available and decreasing the likelihood of failure. There are other important considerations as well, including hardware age, the general availability of supported replacement parts, reliability requirements, and experience with similar initiatives/projects. However, lifecycles and available support agreements are the major determining factor for product replacement and are determined by the individual vendors. The dynamic architectural model requires Hydro One to plan and replace devices with the appropriate current technology and involves consistent assessment of available technologies and their versatility and compatibility with current and future needs. It is recommended as the only viable option. This option offers the following benefits:

- Continued availability and compliance with reliability standards;
- Current market product maintenance and vendor support;
- Original Equipment Manufacturer ("OEM")/vendor provided updates and software patches;

- OEM/vendor available replacement parts; and
- Improved ability to recover from random failures.

Through systematic replacement of common IT infrastructure, Hydro One can sustain business functions by ensuring that tools and systems used to support grid operations are functioning as designed and are fully vendor supported. This provides the assurance to Hydro One customers that IT failures are minimized and systems are returned to service in a timely fashion. This approach maintains Hydro One's commitment to customer satisfaction by ensuring responsiveness through system availability.

E. EXECUTION RISK AND MITIGATION

Replacing *end-of-life* infrastructure assets is recommended as best practices in order to maintain Hydro One's currently supported, compatible, and redundant IT infrastructure and equipment. The ongoing dynamic processes to cost effectively assess, prioritize, and stage each product in its respective category must remain in focus by the Hydro One Power System IT architecture team at all times in order to achieve success in each individual project. The driving focus behind these processes is to maintain current reliability and service levels with the continued support of mission critical applications whose function is to serve Hydro One customers in the most cost effective manner possible while maintaining compliance.

GP-07 Hardware/Software Refresh and Maintenance

Start Date:	Q1 2020	**Priority:**	High
In-Service Date:	Program	**3 Year Test Period Cost ($M):**	6.0
Trigger(s): Productivity			
Outcomes: Operational effectiveness, reliability of enterprise & customer applications, reduced risk of failure			

A. OVERVIEW

This investment plan involves the replacement of aging hardware and the upgrade and patching of existing enterprise applications. The planned investments relate to the implementation of Enterprise Resource Planning ("ERP") applications and related tools including SAP, further Information Technology security access control and monitoring capabilities, middleware and databases, productivity tools, and server upgrades to keep the data center infrastructure vendor supported and to make improvements to the disaster recovery platforms. These investments are required in order to ensure continued operational effectiveness, maintain the reliability of critical customer applications and build contingency so as to ensure that critical systems are available and can survive a system failure. The proactive investment approach reduces the risk of prolonged system outages and reduces the costs of unplanned investments to resolve failures. The projected costs of the project are estimated to be $13.7 million over the 2020-2024 planning period.

B. NEED AND OUTCOMES

Investment Need

Hydro One makes significant investments in enterprise technology to ensure the reliability and availability of business critical systems. This investment plan achieves this through the replacement of aging hardware and the upgrade and patching of enterprise applications. Most notably, Hydro One has made significant investments in SAP, Microsoft and a Geographic Information System ("GIS"). These enterprise systems enable meter data aggregation, some billing, and settlement activities. The enterprise systems also provide the backbone of business operations within finance, human resources, supply chain management as well as asset and work management for the field staff. Asset Management is responsible for defining the investment plan for Hydro One's distribution and transmission networks, and the management of these investments. Work management is responsible for the execution of projects and programs. The reliability of these systems is critical to keeping Hydro One's business running effectively. The investment plan maintains the Enterprise systems at service levels aligned with business criticality as defined in Exhibit B, Tab 1, Schedule 1 (TSP), Section 2.3.3.3.

In addition to ensuring operational effectiveness, the investment plan ensures critical customer applications and supporting systems are reliable and available to customers. Key systems and the data generated will always be available (99.5%) to customers and employees involved with the delivery of our customer service programs and work management programs linked to Hydro One customer satisfaction goals Key Performance Indicators ("KPI"s). For example, Customer Satisfaction is a KPI on the Hydro One Corporate Scorecard. Hydro One therefore strives to ensure the customer supporting systems such as Microsoft CRM, Customer Information Services, and Itron are reliable and available. Microsoft CRM enables the management of customer information, projects and customer communications; Customer Information Systems enables the effective execution of customer settlements; Itron enables the aggregation of meter data in support of customer billing. Further, SAP Work Management Systems enable timely connection of customers and demand related activities.

Assets included in these systems are mainly application software and the associated hardware (servers and storage). The primary enterprise application is SAP. SAP is a vital component in supporting a variety of customer services such as settlements and some billing functions. SAP is the source of truth for the data and is the information system that drives all of these customer actions.

Investments are required to build contingency so as to ensure that critical systems are available and can survive a system failure (result of a manufacturer bug, security patch, etc.) of any single supporting technology component. Investments in supporting technology components include telecom, Information Technology ("IT") hardware and software. Leveraging these investments with effective vendor maintenance means that the assets can be fixed and/or replaced expeditiously in the event of failure. To that end, Hydro One adheres to an IT industry standard practice of managing its assets through a lifecycle program ensuring vendor support is available and decreasing the likelihood of failure. Funding decisions are made based on software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives/projects.

Investment Description

In 2020 to 2024, the planned investments relate to the implementation of ERP applications and related tools including SAP, further IT security access control and monitoring capabilities, middleware and databases, productivity tools, and server upgrades to keep the data center infrastructure vendor supported and to make improvements to the disaster recovery platforms. New applications are driven by business needs and technology requirements. Existing applications that are approaching end of vendor support are upgraded to current versions and the supporting hardware is either refreshed or maintenance is extended. Investment related to hardware and server upgrades is variable by project and the complexity of the architecture. Where possible, Hydro One upgrades and refreshes hardware concurrently.

Refreshes for applications that are currently in sustainment are funded from this investment. The only exception is if the refresh is going to drive new functionality that can be tied to a business case. In that case, the investments will be treated separately and not included in the cost estimates. The cost estimates for this program are based on "like for like" refreshes of applications already in sustainment. The refresh activity is part of maintenance and supportability of that application asset. Any new functionality required by the business requires a business case that would drive the additional release of funds.

Lastly, a system being refreshed in order to accommodate its inclusion into the Disaster Recovery Program (“DRP”) would also be funded by this investment.

Assets are replaced as they approach end of life. At the time of replacement, investments are sized in order to support future demand and growth as well as ensuring the architecture is redundant and thus remains available to users in the event of a disaster (for example, investment is required to ensure critical systems have disaster recovery capabilities), thereby building contingency into the new asset investment.

Outcomes

This proactive investment approach reduces the risk of prolonged system outages and reduces the costs of unplanned investments for problem resolution. This investment in IT system reliability enables general employee productivity as it will allow internal users to have access to the tools they require to work and minimize downtime. The investment also enables customer satisfaction through increased availability of enterprise wide applications and, outage management systems.

The following table summarizes the anticipated benefits as a result of this project:

Customer Focus	• Ensure IT Hardware / Software is supported and reliable to prevent information gaps for customers. • Performance and Stability of IT Hardware / Software directly impact ability to service customers in a timely manner (i.e.: Outages, Billing Inquiry, Program Enrollment, etc.)
Operational Effectiveness	• Maintain the reliability of IT Hardware/Software to allow applications / systems to function as designed and provide Hydro One employees with the information they require to perform their daily work.
Public Policy Responsiveness	• Maintain efficacy of the IT systems that interact with market participants and support the IESO in its market oversight mandate.
Financial Performance	• Overall costs are minimized, by reducing the potential for costly outages and unplanned refreshes or upgrades.

C. EXPENDITURE PLAN

Estimates are driven by historical costs, which are determined by the inherent lifecycle of the devices. In order to calculate the cost estimations, Hydro One reviews the past actual spend over a 3-5 year period. As assets “cycle” at the same rate and are managed under an asset lifecycle program, future investment needs can be projected based on historical investments. The forecasted spending in 2020-2023 is lower than historical levels as some of the future spending was advanced to 2018-2019. In 2024 the spending is forecasted to return to sustainable levels in line with historical spending.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years[1]	2020	2021	2022	2023	2024	Forecast 2025+[1]	Total
Capital[2] and Minor Fixed Assets	-	2.0	2.0	1.9	1.9	5.8	-	13.7
Less Removals	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Gross Investment Cost	**-**	**2.0**	**2.0**	**1.9**	**1.9**	**5.8**	**-**	**13.7**
Less Capital Contributions	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Net Investment Cost	**-**	**2.0**	**2.0**	**1.9**	**1.9**	**5.8**	**-**	**13.7**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown
[2] Includes Overhead at current rates.

D. ALTERNATIVES

Alternative 1: Delay Refresh

This alternative would defer replacement of assets due for refresh and maintain the status quo. This alternative was rejected as it would create additional issues caused by increasing failure rates of the systems.

Extending the timeline of the current life-cycle asset refresh strategy and delaying replacement of assets takes Hydro One out of line with industry practice and significantly increases risk to the business in the following areas:

- Increases in employee dissatisfaction and decreased productivity due to frequent and/or prolonged service outages;
- Degraded regulatory relationship from disruptions to market operations of IT systems that interact with market participants;
- Decrease in customer satisfaction due to failure of enterprise wide applications such as SAP, ihub/Tivoli, Microsoft Exchange, mobile applications, customer billing, relationship management, and call centre systems; and

- Productivity declines due to the high unit cost of supporting and servicing applications without vendor support.

Alternative 2: Refresh Per Plan (Recommended)

This proposed alternative would replace servers within life cycle guidelines. A number of factors drive the refresh of an application. This investment covers the capital costs, including Professional Services, to build new Web/Database/Application and Infrastructure servers along with all relevant data migration, Operating System, hardening, and decommissioning activities. There are a number of factors that drive hardware refresh – vendor supportability being a primary driver. There are other important considerations as well, including hardware age, and the general availability of supported replacement parts. Additional application functionality or performance considerations will also drive a refresh. Assets will be replaced in line with vendor support timelines, or**,** if there are new business requirements that require new functionality and/or increased performance of an asset, Hydro One will evaluate a refresh or replacement of an asset.

Server hardware is refreshed every 3-7 years based on hardware type. Hardware refresh is required to support enterprise applications from a performance/capacity and overall availability perspective to meet both customer and business expectations. Hardware refreshing per scheduled plan allows for sustainment costs to be favourably negotiated due to technology improvements being implemented as part of new deployments.

From an application perspective, today's business demands performance levels that are only offered by the latest server hardware and network technologies. From a technology perspective, the entire IT market continues to virtualize and optimize key areas that are common across all data-centres – virtualizing server compute, storage and network. Through the virtualization of our IT assets, IT becomes more responsive and agile to evolving business needs. As such, replacing old hardware with new technologies enables us to reduce our physical asset footprint and move to an increasingly virtual environment. This not only decreases our cost of maintenance but also increases our ability to service the business. Refreshing the current aging hardware allows for greater scalability and higher server densities, since it is possible to run additional virtual servers with a smaller hardware footprint.

E. EXECUTION RISK AND MITIGATION

No unique concerns are foreseen with completing the Hardware/Software refresh program beyond generic project risks, such as schedule delays, business disruption, and system outages. Any project risk is mitigated through stakeholders and modification of scope to reach desired business outcome. Through project governance, risks are proactively communicated, evaluated, and managed by project/program leadership and/or a steering committee, when applicable.

Any risks around resourcing, with respect to specific skillset requirements, will be addressed with systems integrators prior to awarding the project. The award will ensure proper expertise is maintained during the life of the project and is well documented as part of the execution scope.

GP-08 Corporate Services Transformation – HR/Payroll

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Q2 2021	**3 Year Test Period Cost ($M):**	6.5
Trigger(s): Strategic, Productivity			
Outcomes: Increased operational effectiveness, superior performance, consistent processes, cost savings			

A. OVERVIEW

This investment involves the implementation of a new Human Resources ("HR") and Payroll solution developed with SAP SuccessFactors as the main enabling technology platform. HR and Payroll are currently experiencing a number of operational challenges and have identified a number of improvement opportunities in the operations. Delivery of HR and Payroll services currently rely on the use of manual and MS Excel-based processes built around a relatively customized SAP system and near end-of-life or legacy systems. The proposed new solution offers improvement in HR and Payroll-related processes and will reduce the need for outsourcing to third parties. The projected costs of the project are estimated to be $6.5 million over the 2020-2024 planning period.

B. NEED AND OUTCOME

Investment Need

The HR and Payroll organizations are seeking enhancements to their operating models to better serve staff as well as stakeholders. Improvements are being sought to address the following areas: (a) changing workforce demographics and expectations; (b) the company's increasing use of a more flexible workforce (e.g. through hiring halls); (c) elimination of process and system-related inefficiencies (due to a significant degree of customization on the current system and manual & paper-based processes); and (d) the ability to process payroll, travel and board transactions efficiently and accurately. Meanwhile, SAP is re-architecting its solutions and support structure, with on-premise ERP-ECC applications no longer supported after 2025. SAP's HR module and functionalities will be transitioned from the ECC-based HR System to cloud-based SuccessFactors applications.

HR and Payroll are currently experiencing a number of operational challenges and have identified a number of improvement opportunities. The 2017 HR Effectiveness Survey conducted by HR in relation to HR services identified further process and operational improvements that can be enabled by a robust and modern technology platform. Examples of the improvement opportunities include: (a) payroll processing cost savings; (b) reduction in manual processes with respect to master data maintenance, error corrections and timesheet entries; and (c) automation in the areas of scheduling, employee ID creation and authentication management.

Delivery of HR and Payroll services currently rely on the use of manual and MS Excel-based processes built around a relatively customized on-premise SAP system and near end-of-life or legacy systems (e.g. PeopleSoft, Lotus Notes). Substantial portions of these functions are currently outsourced to a third party (Inergi) and Hydro One is in the process of renegotiating such agreement in view of the expiry of the existing outsourcing agreement in 2019.

While the switch to the new solution will not necessarily eliminate the need for third party outsourcing, the new platform and solution offers improvement in HR and Payroll-related processes – many of which are currently being provided by Inergi. As such, it would provide Hydro One with strategic leverage and negotiating power with Inergi should it decide to renew the contract or with other third party outsourcing service providers such as ADP or Ceridian should the company elect to change the service provider.

Investment Description

This investment involves the transformation of HR and Payroll processes with SAP SuccessFactors as the main enabling technology platform. Implementation of the project will be broken down into logical work streams aimed at achieving the following objectives and business outcomes: (a) Optimizing Talent Management and HR Performance; and (b) Time and Payroll Optimization and HR Modernization.

The technology architecture and solution will serve as the key enabler to the business transformation and will include key SAP SuccessFactors modules on HR as well as Time & Attendance applications. Overall, the scope will include:

- Implementation of new HR and Payroll business processes and technologies required to build capabilities and flexibilities across the in-scope functions; the in-scope functions include all core HR functions currently handled through the existing on-premise SAP HR system such as recruitment, organizational management, employee master data management, time & attendance and payroll processing.
- Formulation and implementation of new HR and Payroll operating models that will leverage the HR, Time & Attendance and Payroll Processing technology solution as the basis for improving the delivery of the HR and Payroll services in an integrated manner; and
- A technology architecture and solution that is aligned with Hydro One's IT Strategy and enterprise standards and leverages the investments made in other technology solutions such as the mobile platform.

Outcomes

The following table summarizes the anticipated benefits as a result of the project:

Operational Effectiveness	• Optimize standardized SAP processes, increase operational effectiveness through simplified user interfaces, superior performance and more consistent processes such as: o Enterprise-wide – provides leverage for outsourcing negotiations with the third party and provides a platform to support new Corporate cultural values through better in-sights-driven analytics; o Time and Attendance-related – moving to positive pay (without planned time) improves accuracy of employee pay, reducing unknown overpayments; o Manager and Employee Productivity – simplifies time entry and approval process and reduces administration burden, increasing employee productivity, and accelerates on-boarding time to make new employees productive, earlier; and o Data-related – enables more detailed data capture and reduces the risk of over payment by improving processes and strengthening controls.
Financial Performance	• Drive opportunities for cost savings and productivity gains such as: o Payroll Processing Cost Savings – Reduction in overpayments and improvements in process efficiencies with process automation and standardization; o Process Standardization Cost Savings – Improvements in process efficiencies with process standardization for HR and Payroll; o Process Automation Cost Savings – Improvements in process efficiencies with process automation for HR and Payroll; o Hydro One Full Time Equivalent Cost Savings – Reduction in cost for minor enhancements and support; and o Application Landscape Rationalization and Maintenance Cost Savings – Application elimination and reduction in costs to complete minor enhancements and support.

C. EXPENDITURE PLAN

The estimated project implementation cost includes the costs for the System Integrator, Inergi (as they are currently managing and supporting the existing system) ,and SAP (for Software Licenses and QA services) as well as Hydro One costs (for Project Management, Change Management, and Security). These costs were an output of the Discovery and Assessment work done by PwC in collaboration with HR, Payroll and IT. In addition there will be recurring software licensing & maintenance costs, but these are covered by IT's sustainment OM&A budget and are not within the scope of this investment.

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	1.7	5.0	1.5	0.0	0.0	0.0	0.0	8.2
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**1.7**	**5.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**8.2**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.7**	**5.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**8.2**

[1] Includes Overhead at current rates.

D. ALTERNATIVES

Alternative 1: Status Quo

This alternative contemplates no changes being made to the current HR and Payroll operating models. This alternative was rejected as it does not address the operational challenges currently faced by these departments. Maintenance of the status quo also means that the realization of associated benefits of the improvements identified will not be achieved.

Alternative 2: Cloud-based Solutions

Alternative cloud-based solutions (such as Workday, Oracle Fusion etc.) were considered. However, Hydro One has already made a substantial investment in SAP and the cloud-based SAP SuccessFactors platform. Additional investment in any of these alternative solutions will result in much higher systems integration costs and other costs as the existing SAP HR technology infrastructure would need to be replaced in its entirety. Therefore, this alternative was rejected.

Alternative 3: Transformation of HR and Payroll models (Recommended)

The recommended alternative is to pursue HR and Payroll transformation with SAP SuccessFactors as the main enabling technology platform. This will ensure that the solutions will be consistent with the company's IT Strategy of transitioning from a highly customized solution towards standard SAP processes and functionalities, leveraging industry best practices and providing a more cost effective solution. To facilitate execution, the implementation will be broken down into logical work streams aimed at achieving the following objectives and business outcomes: (a) Optimizing Talent Management and HR Performance; and (b) Time and Payroll Optimization and HR Modernization.

E. EXECUTION RISK AND MITIGATION

Following Project Approval by the Executive Leadership and the Project Governance bodies, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted on a quarterly basis thereafter. This is a line of business project that will be led and owned by the appropriate lines of business, supported by proven SAP and IT solution project execution methodologies and standards.

Key factors (medium-level risks) associated with the project include:

a) Possible underestimation of the degree of organizational change a transformational initiative of this type actually entails. *Mitigation*: A comprehensive Organizational Change Management ("OCM") strategy will be developed and implemented from the outset of the project. The strategy will include: (a) ensuring the OCM is involved in the project at an early stage in the process; (b) undertaking a comprehensive stakeholder assessment; (c) critical assessment of the impact of the new process and systems to the current functions and organization involved; (d) a comprehensive training strategy and plan; and (e) a proactive and effective communication plan.

b) Outcomes of Labour Relations' re-negotiation of collective agreements Society of Engineering Professionals (2019). Procedures and solutions within the scope of this project will touch on processes driven by existing collective agreements. As such, significant changes to the agreements may pose constraints with respect to the implementation of the target solutions (particularly with respect to time & attendance, payroll, travel and lodging), which could put the achievement of the anticipated project benefits at risk. *Mitigation*: Union representatives and other relevant stakeholders will be engaged from the outset of the project.

c) Decision on Payroll Operating Model prior to Inergi contract renewal in 2019. *Mitigation*: Hydro One's Payroll team and key stakeholders will be engaged throughout the project. As the Payroll Operating Model and contract with Inergi are reviewed, the impact(s) of these on the HR Operating Model and the activities within the project work streams will be monitored on an ongoing basis.

GP-09 Corporate Services Transformation – Finance

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Multiple	**3 Year Test Period Cost ($M):**	9.0
Trigger(s): Strategic, Productivity			
Outcome: Operational efficiencies, process simplification, improved data and decision-making, reduced inconsistencies in reporting			

A. OVERVIEW

The company requires an upgrade to its Finance function to provide greater capability and flexibility to respond to increasing demand for accurate and timely reporting, ensure data integrity, provide better planning and analytics, and efficiently/effectively service its internal and external stakeholders. To achieve this, Finance needs to include processes for transaction processing, planning, reporting and analysis that optimize standard SAP processes, leverage industry best practices and take advantage of capabilities provided by new technologies. These improvements will enhance overall end-user experience, drive productivity gains and realize sustainable cost savings. The projected costs of the project are estimated to be $20.5 million over the 2020-2024 planning period.

B. NEED AND OUTCOMES

Investment Need

This investment is required in order to migrate to the new S/4HANA platform being developed by SAP prior to losing support on the existing applications in 2025.

Hydro One currently uses multiple systems to enable Finance perform its functions and provide service to its stakeholders. Such systems include SAP Business Intelligence (“BI”), SAP Enterprise Resource Planning Central Component (“ERP-ECC”), SAP Business Planning and Consolidation (“BPC”) and MS Excel. Over the past 10 years, Hydro One has consolidated over 130 applications, and the functions they performed, into SAP, which resulted in Information Technology (“IT”) and business process savings, such as reduced manual effort with respect to transaction processing, report generation and data reconciliation. However, there are still process inefficiencies, data integrity issues, long reporting cycle times and complexities and high cost in managing and supporting such systems.

To support the business, Hydro One's Information & Solutions Division ("ISD") needs to have: (a) strategic options on IT architecture and support model; (b) capability to develop and deploy new advanced planning and analytics with reduced effort and shorter timelines; (c) advanced capabilities for managing and analyzing big data sets and applying advanced algorithms and robotic trends.

SAP has, over the past three decades, created a platform that can be configured to perform any one business function in multiple ways. While "best practice" has always been built into every SAP transaction, user interpretation of what data needs to be inputted has led to inconsistent transaction processing and erroneous or missing data. In addition, SAP is currently re-architecting its solutions and support structure and shifting its product development efforts towards their new S/4HANA platform. This new platform promises to deliver core ERP-ECC capabilities in one place with one underlying data store, thus providing their customers with a centralized and streamlined system, with greater computing power, flexibility and data integrity. As a result, SAP has announced that their on-premise ERP-ECC applications will no longer be supported after 2025. There are some alternatives that Hydro One can consider. However, if Hydro One continues to be on SAP, all business functions using SAP will ultimately have to migrate to the new S/4HANA platform prior to 2025.

Investment Description

Finance as well as the upstream and downstream functions currently relies on the relatively customized on-premise SAP ERP systems as well as a significant number of manual and MS Excel-based workaround processes. A substantial portion of these functions are also currently outsourced to a third party (Inergi) and Hydro One is in the process of renegotiating such agreement in view of the expiry of the existing outsourcing agreement in 2019**.** The switch to S/4HANA per se will not eliminate the need for Inergi. However, the new platform and solution offers more power, analytics capability, streamlined processes, reduced manual effort, among other things; a lot of which is currently being provided by Inergi. As such, it would provide Hydro One with strategic leverage and negotiating power.

The Finance transformation project, as enabled by the new S/4HANA platform, will include:

- Re-engineering (as required) of relevant business processes to build target capabilities and flexibilities across the in-scope functions, move towards standard SAP processes, and leverage industry best practices. This will result in more efficient processes, reduced manual effort, shorter cycle-time, enhanced data integrity and greater reporting and analytics capability;
- A new Finance Operating Model that will leverage S/4HANA functionalities, enhanced computing power and better end-user interface; and
- A technology architecture that is aligned with Hydro One's IT Strategy and enterprise standards and leverages the investments made in other technology solutions (such as the mobile platform). As Hydro One relies significantly on SAP, the IT strategy is to be aligned with the SAP roadmap and standards, including mobility solutions.

S/4HANA is a real-time ERP suite that can form the digital core of the business. The promise of S/4HANA includes:

- Simplified functionality, with the elimination of redundantly-mapped business requirements which make promoting innovation difficult and cause data integrity issues and manual workaround processes;

- Simplified data structure eliminating data redundancy and providing end-users with faster access to data to generate real time reporting, ultimately reducing the time to close the books by 10 – 20% according to SAP estimates;
- An in-memory platform that provides better system performance. Additionally, new systems provide the ability to facilitate predictive forecasts and dynamic simulations using real time data to provide greater reasonability to the numbers. Embedded predictive algorithms and simulation capabilities enable management to better and proactively monitor and forecast business needs; and
- An intuitive, role-based user interface (SAP Fiori) structured on advanced design principles and simplified system landscape.

While the initial focus during the earlier years of the planning horizon will be the relevant finance modules and functionalities, the later part of the planning period will look into the upstream and downstream modules (e.g. those related to customer, enterprise asset management, supply chain, etc.) required to optimize full integration and realization of overall business benefits.

Outcomes

This investment will yield operational efficiencies, improved decision-making through real time reporting, process simplification and better data driven by standard and consistently performed transactions and better user adoption due to a simpler and more modern interface.

The following table summarizes the anticipated benefits as a result of the project:

Operational Effectiveness	• Increase operational effectiveness through simplified user interfaces, superior performance and more consistent processes. • Drive opportunities for cost savings through leaner processes and in-platform planning and reporting.
Public Policy Responsiveness	• Improve capability to meet statutory reporting requirements.
Financial Performance	• Reduce the inconsistencies in month end reporting through simpler user interfaces and consistent process execution.

C. EXPENDITURE PLAN

The underlying premise is that S/4HANA will help Hydro One fine-tune the current system investments, not reinvent them. This will extend the investment in the current SAP ERP that was implemented in phases between 2008 and 2013.

Hydro One will also initiate an open competitive bid process for the implementation stage of the investment so multiple vendors will be able to submit their proposals. There will be a need for a System Integrator. In addition, specific vendors for specific requirements will be required. Inergi will also be involved as they are currently managing and supporting the existing system. SAP of course will provide the Software Licenses and QA services as required. There could also be hardware requirements depending on the final strategy. Hydro One will select the most qualified vendor that best meets Hydro One’s evaluation criteria and budget.

The strategy is to have a phased implementation. Core Finance functionalities will be the focus for the initial year, followed by Logistics and Enterprise Asset Management modules. The last module to be implemented will be the Customer-related module. This approach enables Hydro One to implement the core functionalities as soon as possible, while at the same time making the most of recent investments - particularly on Move-to-Mobile and Customer-related modules

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	1.0	1.0	3.0	5.0	6.5	5.0	0.0	21.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**1.0**	**1.0**	**3.0**	**5.0**	**6.5**	**5.0**	**0.0**	**21.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.0**	**1.0**	**3.0**	**5.0**	**6.5**	**5.0**	**0.0**	**21.5**

[1] *Includes Overhead at current rates.*

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking:

Alternative 1: Status Quo

This alternative would require Finance to continue to use/rely on the current BI and ECC platforms in conjunction with other applications to produce financial statements and conduct reporting. This platform will reach end-of-life status by 2025 and will put the company at risk due to loss of vendor support, which would then require Hydro One to invest heavily on resolving any future issues or implementing fixes on its own. In addition, Finance will continue to perform its functions at a sub-optimal level and give up the opportunity to generate cost savings and productivity gains.

Alternative 2: Replace SAP with an alternative software system

This alternative would replace the current SAP BI platform with competing Enterprise Resource Planning ("ERP") software and/or adopt a multi-vendor approach by replacing the various business functions with Commercial Off-The-Shelf ("COTS") applications.

However, there could be differences in functionalities to those offered by SAP. This alternative is not justifiable due to the investment Hydro One has currently made in SAP technology, that would be lost if a replacement platform was adopted. In addition, moving to a new non-SAP platform would entail changes to processes and significant training/change management requirements. Therefore replacing the existing systems with COTS applications would not be justifiable.

Alternative 3: Finance Transformation enabled by S/4HANA (Recommended)

The recommended alternative is to pursue Finance Transformation, with S/4HANA platform as the technology enabler. This will ensure that the solution will be consistent with the company's IT strategy, and contribute to the objective of moving towards standard SAP processes rather than reliance on extensive customization. The investment will also leverage industry best practices and aim for the most cost effective solutions. In addition, it will assure continued vendor support over the long-term to keep IT costs in check and ensure ongoing timely performance.

S/4HANA has a streamlined user interface which has been built upon the same design concept that most mobile applications use which is to present the user with exactly the data they require and limit input options. Training will be required for use of the new interface, and all components of the solution as well as corresponding process changes. However, the interface is much more user-friendly than the existing solution. On the S/4HANA, platform business functions or processes have been simplified resulting in less time required to perform the associated processes and with improved data quality.

A major architectural shift in S/4HANA Finance is the use of what they refer to as the Universal Journal, which would serve as a single source of truth with respect to financial elements of a transaction. Currently, each module or sub-ledger has its own master data elements, which poses a lot of reconciliation challenges between modules. The database structures have been greatly simplified. SAP has done away with the sub ledger/ledger design thus increasing performance. As part of the implementation, baseline performance metrics will be determined against which performance of the new solution will be measured.

E. EXECUTION RISK AND MITIGATION

Following the project approval by the Executive Leadership as recommended by the Project Governance structure, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project milestones. The following are the risks that the project plans to address and manage:

Solution Complexity

The S/4HANA delivery is expected to be a complex implementation and finding the right skill set to support successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience & expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP, and Enterprise Architecture resources. All of these resources are integral to success of the project. To mitigate this risk, the eventual Implementation Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Any combination of these risks could result in a project in-servicing delay. To minimize the risk, solid project governance will be applied taking into account the relevant lessons-learned from other similar projects.

Change Management

As this initiative is transformational, there will be significant change which will impact both Finance (and potentially other Lines of Business), Investment Summary Documents and Inergi. To mitigate the risk, Hydro One Change Management Organization will be engaged throughout and a robust change program will be part of the scope of the project.

GP-10 Facility Accommodation & Improvements Service Centres & Admin

Start Date:	Q1 2020	**Priority:**	Medium
In-Service Date:	Program	**3 Year Test Period Cost ($M):**	21.2
Trigger(s):	Safety, Reliability, Immediate/Short Term Compliance, Strategic, Corrective Maintenance, System Renewal.		
Outcomes:	Lower maintenance costs, improved operational performance, regulatory compliance, enhanced health & safety, reduced risk of component failure, improved life cycle management, adaptability		

A. OVERVIEW

This investment entails improvements or additions to existing field facilities and/or the construction of new facilities as needed. The impacted field facilities include administration centres, operation centres, warehouses, heliports/helicopter hangers, fleet garages, as well as the head office and other Hydro One office spaces. Without the necessary capital repairs, upgrades and replacements, facility conditions will deteriorate to the point where Hydro One's operational efficiency and personnel safety become impaired. Through this program, Hydro One expects to achieve the following: lower maintenance costs, improved operational performance, regulatory compliance, enhanced health and safety, reduced risk of asset failure resulting in business disruptions, and adaptability to accommodate known or anticipated changes to the business. The projected costs of the project are estimated to be $41.9 million over the 2020-2024 plan period.

B. NEED AND OUTCOME

Investment Need

The field facilities that need to be addressed through this investment include administration centres, operation centres, warehouses, heliports/helicopter hangers, fleet garages, and all sites that are not transmission stations (including the head office and other Hydro One offices). This capital work program is designed to addresses field facilities with respect to required improvements, building additions and new facilities, as based on Hydro One's operational requirements and overall building and site condition.

This program ensures that essential and supportive improvements are made to field facilities to minimize building and site related risks, including in terms of health and safety and equipment protection, meeting operational requirements, and promoting efficiencies in facility maintenance and operations over the long-term.

Capital investment in field facilities is periodically required in order to continue to provide appropriate and adequate accommodations for core work programs and changing requirements of the various lines of business. This investment need is driven by the following key factors:

- Deteriorating facilities that require increased maintenance for components in poor condition, to the point where it is more cost effective to replace the component;
- Compliance with current regulatory requirements, such as the *Accessibility for Ontarians with Disabilities Act* and the *Ontario Building Code*;
- Expanding work programs;
- New accommodation needs;
- Evolving work practices;
- Improved health and safety by providing adequate and appropriate space for employees and equipment;
- Improved security; and
- Work efficiency and productivity.

More than 40 per cent of Hydro One’s field facilities are estimated to be more than 40 years old. These facilities are largely undersized, inadequately configured and underperforming relative to current operational requirements, resulting in increased operating costs for maintenance and repair and areas of inefficiencies in facility and business operations.

This program focuses on facility work in the areas of improvements, additions or new facilities. Work will be prioritized and executed on a project basis. Expenditures are limited to the extent required to support business operations in delivering work programs, in alignment with network requirements arising from operational plans and strategies, supporting customer needs, corporate and government policy and regulatory compliance.

Without the necessary capital repairs, upgrades and replacements, facility conditions will deteriorate to the point where operational efficiency and personnel safety become impaired, which will adversely impact Hydro One's ability to carry out its core business and serve customers in an effective manner.

Investment Description

The key program work activities include:

- Addition and/or renovation of existing facilities and the acquisition or development of new facilities to address existing and/or new accommodation requirements;
- Replacement of major building system/components, including roof structures; windows and cladding; Heating, Ventilating and Air Conditioning ("HVAC") systems; electrical, lighting and control systems; and other crucial/fundamental structural elements and building systems that are at end of life based on regular building condition assessments, and monthly inspections of various components; and
- Site-related replacements and additions, including drainage; asphalt, fencing; and septic/well (servicing).

Table 1 shows the expected annual volumes of work, based on project type, anticipated over the 2019-2023 period with New Facilities and Major Renovations accounting for the bulk (approximately 40%) of the program costs.

Table 1 – Net Investments by Category for 2020-2024 in ($ millions)

	2020	2021	2022	2023	2024
New Facilities and Major Renovations	2.7	0.1	3.3	11.4	2.8
Site Improvements (asphalt; drainage; servicing; fencing; security)	1.9	1.1	1.5	0.1	0.1
Building Envelope (roof; windows/doors; cladding)	2.1	2.4	1.5	3.4	-
Mechanical & Electrical (HVAC; lighting; generators)	0.4	0.4	0.6	0.3	0.5
Minor Building Renovations and Furniture	1.1	0.9	1.3	1.0	0.9
Total Net Investments:	8.1	4.9	8.2	16.4	4.3

May not add due to rounding.

Outcomes

Benefits associated with this investment are expected to be realized through a number of areas, such as lower maintenance costs, improved operational performance, regulatory compliance, enhanced health and safety, reduced risk of component failure resulting in business disruptions, improved life cycle performance and adaptability to address known or anticipated changes in business requirements.

This investment will enable Hydro One to achieve the following:

- Meet the current operating requirements of the various lines of business;
- Align commitments (e.g. facility leases) and investments with known and emerging operating requirements and corporate business decisions;
- Effective facilities maintenance through timely replacement of major building systems/components; and
- Enhanced health and safety of employees.

The following table summarizes the anticipated benefits as a result of this project:

Customer Focus	• Improve the ability of the lines of business to address customer needs through facilities that are commensurate with operational requirements.
Operational Effectiveness	• Maintain and improve operational effectiveness of the lines of business through timely and strategic facilities investments.
Public Policy Responsiveness	• Compliance with government policy and regulatory/licensing directives (e.g. Accessibility for Ontarians with Disabilities Act).
Financial Performance	• Cost effectiveness realized through regular condition assessment and timely intervention prior to asset failure. • Cost efficiency realized through facilities investments that align with current and emerging operating requirements and business decisions.

C. EXPENDITURE PLAN

The development of facilities and resulting final cost of a project are influenced by various factors beyond the typical realm of design, such as market, regulatory and site/building conditions/factors. Regulatory and site conditions are somewhat predictable through assessment, which is initiated at the outset of a market. In contrast, the market is highly influential on the final cost depending on availability of suitable sites, market opportunity and competing demand. These market factors could have a significant negative or positive impact on the cost of the project. Therefore, early planning, examination of alternatives and implementation serve to optimise opportunities and neutralise market forces.

The cost for the development and/or renovation of field facilities is controlled where applicable through template design, consistency of application, and the adoption of consistent commercial building standards and practices. Specifically, Hydro One recognises that its operational needs for facilities is relatively the same across the province and seeks maintain a consistent approach and leverage proven design that is cost predictable in construction and maintenance. More so, these facilities are to be developed to prevailing industry building standards for the planned use to ensure an appropriated level of investment, facility performance and maintenance cost.

The program costs outlined below are forecast to be needed to fund required improvements of existing field facilities and the development of new accommodation solutions through renovation, expansion and the acquisition or development of new field facilities as required by the company's work programs. Projects can be multi-year, and in certain instances will depend on the successful identification and acquisition of development sites and in all instances contingent on obtaining the requisite regulatory (including municipal planning) approvals.

Table 2 - Total Investment Cost

($ Millions)[1]	**Prev. Years**	**2020**	**2021**	**2022**	**2023**	**2024**	**Forecast 2025+**	**Total**
Capital[2] and Minor Fixed Assets	0.0	8.5	5.3	8.6	16.8	4.4	0.0	43.6
Less Removals	0.0	0.4	0.4	0.4	0.4	0.1	0.0	1.7
Gross Investment Cost	**0.0**	**8.1**	**4.9**	**8.2**	**16.4**	**4.3**	**0.0**	**41.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**8.1**	**4.9**	**8.2**	**16.4**	**4.3**	**0.0**	**41.9**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown
[2] Includes Overhead at current rates.
[3] The annual investment cost fluctuations are due the cost of new facilities that are only periodically initiated in support of the transmission program.

D. ALTERNATIVES

Alternative 1: Status Quo

This alternative is to effectively defer future investment to a minimum in an attempt to continue to operate within the current, out-dated field facilities.

This alternative is not sustainable. Without the necessary capital repairs, upgrades and replacements, facility conditions will deteriorate to the point where operational efficiency and personnel safety become impaired. Any incidents arising from such risks would hamper Hydro One's ability to operate its business and serve customers. For example, a roof failure at an office building will result serious safety concerns as well as displaced staff, which will result in the need for alternate office space, increased costs, and inefficiencies. This alternative would require additional operating expenses for maintenance repairs, including for HVAC systems and roofing systems. Due to the unacceptable risks and cost consequences stemming from this alternative, it is not recommended.

<u>Alternative 2: Update Field Facilities (Recommended)</u>

This alternative would bring field facilities to an acceptable state of repair and make strategic additions or replacements according to a cost-benefits analysis. The cost-benefits analysis is undertaken during the development of the business case for the project, and incorporates relevant considerations such as trends in maintenance costs and the frequency of trouble calls in relation to the particular equipment and components.

The spending requested herein is an estimate of the work to be performed over the planning period. The management of field facilities entails an on-going comparative evaluation of alternatives, including the expansion and/or renovation of existing facilities, the lease or purchase of suitable facilities and greenfield developments against maintenance of the status quo condition. The specific work to be executed from year to year will be scoped and finalized based on the specific circumstances of each project. The objective is to pursue the most cost effective strategy that addresses operational requirements and mitigates risks. Operational considerations are for both existing and future requirements. Consideration of future requirements incorporates potential changes to the business. Each project will be subject to analysis and approval based on its benefits prior to implementation.

An overarching consideration is to maximize the value of existing field facilities through ongoing operations, maintenance and sustainment investments in line with operational requirements. Where facility and/or operational condition and requirements warrant an examination of facility alternatives, the objective is to derive the greatest net assessable benefit to the company.

E. EXECUTION RISK AND MITIGATION

Cost certainty for new operating centres is established through the use of a scalable template design and experience from recently completed projects. Developments are completed in accordance with applicable commercial standards and practices.

Development of new facilities will in many instances depend on the availability of suitable sites and ability to obtain municipal approvals, which can be managed through advance planning and acquisition. Development interests are cultivated by leveraging coordination with applicable municipal officials and departments, and effectively utilizing the services of the real estate and development community. In this regard, advance planning and engaging the right parties can allow risk to be mitigated by obtaining the requisite approvals ahead of time and proactively managing the often lengthy regulatory timelines involved in the development of sites and.

GP-11 Transmission Facilities & Site Improvements

Start Date:	Q1 2019	**Priority:**	Medium
In-Service Date:	Program	**3 Year Test Period Cost ($M):**	28.5
Trigger(s): Preventive Maintenance/System Renewal, Corrective Maintenance, Strategic, Productivity, Immediate/Short-term Compliance, Safety			
Outcomes: Maintain and/or improve system reliability, maintain and improve operational effectiveness, compliance with government policy and regulatory requirements, cost effectiveness realized through regular condition assessment and timely investments			

A. OVERVIEW

This investment pertains to the improvement and replacement of Transmission Station ("TS") Facilities, which includes building assets and facilities' infrastructure. This investment mitigates system reliability and safety risks associated with deteriorating and/or failing building assets, site infrastructure, and environmental risks associated with non-compliance; for items such as septic systems and release of halocarbons into the environment from aging Heating Ventilation and Air Conditioning ("HVAC") systems. The planned investment involves replacement of essential building assets and site improvements including but not limited to the building envelope, roofs, HVAC systems; required for sensitive transmission system protection and control equipment, building auxiliary systems, cranes, and elevators at Hydro One TSs. The investment will also help optimize capital expenditure through timely and cost-effective maintenance of operating requirements, and compliance with government policy and regulatory requirements. The projected costs of the project are estimated to be $48.1 million over the 2020-2024 plan period.

B. NEED AND OUTCOME

Investment Need

Aging TS facilities across the province require funding to provide for necessary improvements, asset additions, and refurbishments. This funding requirement is also driven by evolving work programs and a dynamic regulatory environment.

On-going building condition assessments provide insight into the overall condition of key facilities assets at TS's in addition to monthly building inspections and annual roof inspections. Furthermore, regular maintenance is carried out on key Facility assets at regular intervals to help maintain their life cycle until replacement. Based on analysis from the condition assessments and other inspections, a capital investment profile has been developed which determines projected end of life for certain building attributes. Without continued investment, the TS Facilities will deteriorate, resulting in increased operating and maintenance costs and potentially compromise the operational integrity and reliability of the electrical equipment, negatively impact work efficiency and effectiveness, and increase the likelihood of health and safety incidents.

The main drivers for this investment continue to be:

- End of life replacement of building assets components;
- Equipment and overall infrastructure that have exhausted their operational life and/or are technologically obsolete, resulting in higher maintenance costs due to scarcity of replacement parts and technical operating knowledge in maintaining and servicing such equipment;
- Higher failure rates due to mechanical/structural issues;
- Stringent regulatory requirements (e.g. building code, fire code, etc.); and
- Maintaining health, safety, and environmental standards by mitigating associated risks associated (for example, investment in well water facilities such as cisterns and septic cisterns for stations that are not on municipal services).

The planned investment entails site improvements and replacement of essential building assets that are now exhibiting diminishing returns when their maintenance costs surpass their serviceable life expectancy and replacement costs. The assets contained in this investment portfolio support the core business in Transmission and Distribution and directly and indirectly impact system reliability, regulatory compliance, and business operations. Direct impact to system reliability would entail projects like roof replacements for relay buildings and other critical buildings that provide support to the network. Indirect impact would be timely replacement of an HVAC system that maintains a serviceable temperature range for the critical equipment contained in the building. HVAC failure in this case would result in equipment failure which would then have a negative impact on supply reliability. In instances where the building asset investments are more incremental, indirect benefits will be realized through improved reliability and reduced maintenance. Changes in the business have also created the need for renovations and/or expansion of existing facilities to accommodate the need for increased staff at specific transmission stations.

This investment mitigates the following corporate risks:

- Reliability: This work program mitigates any system reliability risk associated with failed building assets and site infrastructure necessary to sustain regular operations at TS facilities. Failing to address building asset components such as leaking roofs, lack of cooling for relay rooms, and other end-of-life assets beyond service maintenance life can pose as a moderate reliability risk. While a failed roof or failed HVAC can force an entire station from service, there are systems in place to prevent roof failures, including bi-annual roof inspections to assess condition, which triggers remediation or replacement based on condition assessment. The risk of failure is mitigated through scheduled inspections, maintenance and corrective repairs.
- Regulatory: The Ministry of the Environment, Conservation and Parks and other regulatory bodies stipulate requirements for items such as septic systems and

release of halocarbons into the environment from aged HVAC systems that have reached end of life, as well as a requirement to remove light ballasts containing polychlorinated biphenyls ("PCB") by 2025. In the absence of funding, the regulatory risks associated with these items will be increased and result in potential fines for non-compliance and higher remediation costs for measures taken under emergency situations. The risk is mitigated through regular inspections and maintenance which help reduce risk of end of life failures, and facilitates addressing asset performance in a timely systematic manner.

- Safety: Safety risks posed by aging buildings are mitigated by maintaining the assets through regular inspection, timely replacement before failure, and incorporating safety by design where possible. This approach will minimize likelihood of any equipment failures and accidents and ensure operations remain uninterrupted.
- Customer and Shareholder Service/Value: Incidents resulting from failed assets/components erode customer confidence and relations, service level targets, and affects shareholder value through unplanned costs and reduced revenue.

Investment Description

The facilities department currently manages infrastructure at approximately 331 TSs, which also include facilities serving the accommodation needs of various lines of businesses, in support of the transmission program.

The key investment activities at TS facilities pertain to:

- The replacement of major building system/components, including roof structures; windows and cladding; heating, HVAC systems; electrical, lighting and control systems; and other crucial/fundamental structural elements and building systems that are at the point of failure.
- Site replacements and additions, including drainage; and septic/well (servicing); and water treatment upgrades to improve quality and reliability of water supply,

including conversions to municipal supply that will only occur when financially prudent and when municipal services are extended to the property;

- The addition and/or renovation of existing facilities and the acquisition or development of new facilities to address existing and/or new accommodation requirements;
- Buildings additions and major facility renovations; and
- Dealing with environmental issues that may arise such as mold.

Life cycle optimization practices pertaining to this program are mainly related to analyzing current condition assessment data, past performance, and field input along with detailed building condition assessment that provides insight into remaining life of the asset. Building condition assessments are performed on a five year cycle, while roof inspections are performed annually, and building inspections performed monthly.

Condition/point of failure is assessed based on condition ratings derived from building condition assessments and regular maintenance inspections and based on experience for similar asset components. Site replacements will occur only when condition assessments confirm that the asset is at end of life. Building upgrades that are not associated with a condition assessment include interior modifications such as changes to accommodate disabled employees, or modifications to create work space for additional staff as a result of organizational changes.

Table 1 below shows the number of projects performed on a historic and anticipated basis over the planning period. These projects address replacement of near end-of-life TS facility infrastructure that constitutes the bulk of the program spending. The program has been ongoing since 2015.

Table 1 - Historical and Anticipated Building and Site Improvements

Project	2015	2016	2017	2018	2019	2020-2022
Building Envelope-Roofs	15	9	13	66	15	15
Building Systems - HVAC	6	13	12	10	12	12
Yard Works & Building Structures,	9	6	15	10	15	15

Based on historic spend and conditions, forecasted investment levels are expected to remain relatively stable, reflecting the anticipated costs in the costs table at the end of this document.

There were 66 roof projects in 2018. This increase was a result of a corporate drive to reduce number of roof related outages at TSs. Due to additional funding available, 44 additional critical roofs that accelerated from 2019-2021 in 2018.

Outcomes

Proper maintenance of existing TS facilities results in:

- maintaining system reliability,
- Ensuring operational requirements are addressed in a timely and cost effective manner,
- Maintaining adherence to corporate policies and regulatory requirements.
- Compliance with regulatory requirements and corporate policies;
- Cost effective maintenance of existing TS facilities through timely replacement of major building systems/components prior to failure; and
- Enhanced health & safety of employees operating within TS facilities.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Support of system performance and reliability and the ability of the lines of business to address customer needs through facilities that are commensurate with operational requirements.
Operational Effectiveness	• Maintenance and improvement of operational effectiveness of the lines of business through timely and strategic facilities investments that are aligned with operational requirements.
Financial Performance	• Cost savings realized through the broad consideration of facilities alternatives. • Cost effectiveness realized through regular condition assessment and timely investment prior to failure. • Cost efficiency realized through facilities investments that align with current and emerging operating requirements.

C. EXPENDITURE PLAN

On a yearly basis, the program elements and historical average costs are approximately:

Roofs - Replacements and Capital Repairs (Coating)	~$4M
HVAC	~$2M
Site Works - Septic, drainage, paving	~$2M
Accommodation/Upgrades (including PCB removals)	~$4M

These historical estimates call for a funding envelope of a minimum of $12 to $13 million per year. However, the investment plan currently calls for an average award of $9.5 million per year during the 2020-2022 test period. These cost reductions are possible, but come at a significant cost. The opportunity to achieve the required reduction can be derived from various scenarios:

- Core program elements may be implemented only at point of failure, deferring the funding for the capital sustainment program into future years. This approach has been used historically.
- Given the high risk to operational equipment posed by roof failures, funding continues to be applied to roof replacements, but reductions have been implemented with respect to the coating program (~$1.5 million annually), which

serves to extend the life of the roofs by 10+ years before replacement. The benefit of eliminating the coating program is only a short term gain that will result in higher annual maintenance costs and ultimately increase the number of annual roof replacements, thereby exceeding the cost of the coating program if used as a preventative measure.

- HVAC is generally only undertaken at point of failure. HVAC expenditures are typically small and uneven, which does not allow for the ability to achieve reductions with any certainty.

Facilities staff have a subjective element that allows for adjustment to the timing and magnitude of the work which can achieve incremental cost reductions. However, the magnitude of these adjustments is not material and may result in higher costs impacting future capital or maintenance costs.

To control the actual costs of the implemented projects, majority of contracts are awarded on a fixed price basis.

Table 2 below shows the total planned investment costs from 2020-2022.

Table 2 - Total Investment Cost

($ Millions)[1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	0.0	10.3	10.3	10.4	10.5	10.7	0.0	52.3
Less Removals	0.0	0.8	0.8	0.8	0.8	0.9	0.0	4.2
Gross Investment Cost	**0.0**	**9.4**	**9.5**	**9.6**	**9.7**	**9.9**	**0.0**	**48.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**9.4**	**9.5**	**9.6**	**9.7**	**9.9**	**0.0**	**48.1**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown

[2] Includes Overhead at current rates.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking:

Alternative 1: Status Quo- Run to Failure

This alternative is a "run to failure approach" for building assets and site infrastructure at TS facilities. This alternative represents continued operation with the current state of equipment and infrastructure at these facilities, only carrying out capital expenditure reactively after the occurrence of a failure of equipment, assets, or key site infrastructure.

This alternative was rejected as it undermines system reliability, would be a disruption to business operations, and would result in non-compliance with regulatory requirements and corporate policies. A run to failure approach ultimately increases the likelihood of unplanned system outages and emergency situations that will have a negative impact on system performance, operational efficiencies and costs, health and safety, and customer and shareholder service/value. Typically these buildings house critical assets, and would have direct reliability and customer impacts if the roof were to fail or the cooling system that supports critical infrastructure were to fail. Non-compliance with respect to regulatory requirements could also result in orders to comply issued by the Ministry of Labour or other building code violations.

Alternative 2: TS Facilities and Site Improvements (Recommended) - Maximize Life Cycle & Replacement Before Failure

This alternative maintains aging infrastructure by replacing building assets that are not easily serviceable and have exhausted their operational/performance life by carrying out timely and cost effective site improvements at TS facilities. The spending requested herein is an estimate of the work to be performed over the planning period necessary to keep these assets from reaching failure and causing service disruptions and creating potential health and safety risks. Cost estimates are based off of costs from previous similar projects and estimates from building engineers carrying out the building condition assessments. The objective is to pursue the most cost effective strategy that addresses operational requirements and manages risk. Each substantial investment will be subject to analysis and approval based on its cost/operational benefit prior to implementation.

The prime consideration throughout is to maximize the value of existing TS facilities through ongoing operations, maintenance and sustainment investments in line with operational requirements.

E. EXECUTION RISK AND MITIGATION

A potential risk with this type of infrastructure investment is the prospect of going over budget during implementation. To mitigate this risk, contracts are generally negotiated for fixed pricing which also include a competitive bid process to procure the most suitable vendor, when applicable.

Additional potential risks include unavailability of outages that are sometimes required to perform certain types of work such as roof replacement inside a TS. To mitigate this risk, outage requests will be submitted well in advance of the project dates and the required facilities outages will be scheduled in combination with outages required for power assets.

Execution risk is also mitigated through due diligence process by means of detailed upfront job scoping and asset condition assessments that help develop a comprehensive and accurate scope of work.

GP-12 Transport & Work Equipment

Start Date:	Q1 2020	**Priority:**	Medium
In-Service Date:	Program	**3 Year Test Period Cost ($M):**	39.7
Trigger(s): Productivity Enablement and Cost Avoidance			
Outcomes: Optimize fleet service levels, maximize equipment efficiencies, reduce required repairs and minimize equipment downtime, maintain regulatory compliance			

A. OVERVIEW

The Transport & Work Equipment ("TWE" or "Fleet") program involves the replacement of end-of-life fleet vehicles and helicopters. The program is driven by the need to replace these vehicles based on a thorough review of age, mileage and overall condition, and by the requirement to support Hydro One work programs and staffing requirements (including transmission and distribution capital and Operations, Maintenance & Administration ("OM&A") sustainment, development and operations work programs). This program will result in optimized fleet service levels to mitigate potential delays in response time to unplanned customer incidents, such as trouble calls and storm response and optimal levels of availability of fleet vehicles and other specialized equipment to reduce human effort and minimize risk of personal injury in the field. This program will also benefit employees by ensuring that employees have the right equipment to do their job, thereby increasing employee engagement levels, minimizing risk of injury and increasing work satisfaction. This investment will allow for maximum equipment efficiencies and ensure compliance with all codes, standards and regulations to sustainably manage our environmental footprint. The projected costs of the program are estimated to be $ 66.3 million over the 2020-2024 plan period.

B. NEED AND OUTCOME

Investment Need

The investment to replace end-of-life fleet vehicles and helicopters is required to maintain a healthy and optimal fleet to ensure public and employee safety and compliance with laws and regulations, which include CSA 225, the Highway Traffic Act and the Commercial Vehicle Operator's Registration regulations. TWE plays a wide-reaching and integral role in the day-to-day operations, safety and success of Hydro One's business. Availability of TWE has a direct impact on work program delivery.

Hydro One controls and manages approximately 7,000 fleet vehicles which support the Distribution and Transmission business, including Distribution Lines, Stations, Forestry and Construction Services. Fleet vehicles must be maintained at an optimum level to ensure public and employee safety and compliance with laws and Ministry regulations. These regulatory requirements include, but are not limited to, CSA 225, the Highway Traffic Act and the Commercial Vehicle Operator's Registration regulations. A well-maintained fleet lowers day-to-day operating costs, maximizes line-of-business productivity by minimizing downtime and travel time. Optimal investment levels allow for maximum equipment efficiencies and minimize Hydro One's environmental impact, as newer vehicles emit fewer greenhouse gas emissions due to more efficient vehicle mechanics and enhanced technology.

TWE expenditures for 2020 through 2022 are primarily required to accomplish the following:

- Replace end of life TWE based on a thorough review of age, km and overall condition;
- Support the Hydro One work programs and staffing requirements (including transmission and distribution capital and OM&A sustainment, development and operations work programs); and
- Replace end-of-life helicopters.

The identification of vehicles for replacement are based on industry standards (manufacturer's recommendations) for life cycle expectancy, the remaining net book capital value, operating cost drivers and overall condition assessment of the vehicle.

Light vehicles are replaced after the earlier of six years or 180,000 km. Heavy vehicles have several replacement guidelines depending on the type of equipment: service trucks are replaced after six years or 300,000 km, and single axle work equipment is replaced after eight to ten years or 400,000 km. Tandem axle work equipment is replaced after twelve to fourteen years or 400,000 km. Off-Road and Miscellaneous equipment is replaced on a case by case basis focusing on a condition assessment of the equipment performed by our licensed technicians and ongoing line of business need.

Helicopters are replaced on a case by case basis focusing on a condition assessment of the aircraft performed by the Air Maintenance Engineers, as well as a review of the cost of refurbishment versus the cost of replacement.

Investment Description

The TWE Replacement Program involves capital investment to replace existing TWE that has reached its determined end of life.

Fleet asset capital replacement requirements are based on:

1. Industry standards (manufacturer's recommendations) for life cycle expectancy;
2. Operating cost drivers which are linked to the Business Plan and Work Programs.

Key contributors to the 2020-2022 capital replacement programs include:

- The replacement of core transport and work equipment (about 6% annually, based on replacement criteria described above); and
- Replacement of end-of-life helicopters.

The proposed breakdown of Transmission-allocated spending over the test period is summarized in Table 1 below. Fleet Services performs an on-going assessment of equipment needs and the costs indicated per equipment type may be subject to change based on replacement priorities and available funding.

Table 1 - Forecast of Acquisitions for 2020 to 2022 (Tx Allocation) ($ millions)

Equipment Type	2020 Cost	2021 Cost	2022 Cost
Light	3.3	4.1	2.8
Heavy	4.1	3.2	5.1
Off-Road	1.5	1.5	1.4
Miscellaneous	0.6	0.7	0.2
Service Equipment	1.0	1.0	1.0
Helicopter	2.7	2.7	2.8
Total [1]	**13.2**	**13.2**	**13.3**

Light– cars, SUVs, pickups, vans
Heavy– service trucks, highway tractors, radial boom derricks (RDB), bucket trucks
Off Roads – rubber tire, tracked equipment
Miscellaneous – boats, chippers, tensioners, manlifts, forklifts
Service Equipment – snowmobiles, ATVs, managed Fleet Services.
[1]Total investment costs are based on average unit costs and relate to approximately 400 units annually

Outcomes

The TWE Replacement Program promotes an orderly system of purchasing and funding a standardized fleet replacement program and provides for projected TWE requirements based on work program and staffing forecasts. The TWE Replacement Program incorporates an annual analysis of five-year business planning cycles for capital investment requirements while maintaining a safe and efficient fleet. Evaluation of current spending and forecasted spending requirements will minimize fluctuations in spending and stabilize long term capital investment. The TWE Replacement Program is based on the Line of Business' work program prioritization and future projections and is evaluated against the business plan on an annual basis.

The objective is to maintain a stable fleet replacement program and minimize capital investment fluctuations year-over-year. A reduction in capital expenditures on TWE in a given year can potentially result in increased operating costs, ultimately resulting in increased equipment rates directly impacting the work program costs.

This investment will:

- Ensure compliance with all safety standards, as well as Ministry of Transportation ("MTO") and regulatory requirements;
- Reduce required repairs and minimize equipment downtime; and
- Optimize fleet complement and maximize productivity efficiencies and utilization.

The following table summarizes the anticipated benefits as a result of the program:

Customer Focus	• Optimize Fleet Service levels to mitigate potential delays in response time to unplanned customer incidents, such as trouble calls and storm response.
Operational Effectiveness	• Fleet vehicles and other specialized equipment at optimal levels of availability reduce human effort and minimize risk of personal injury. • Optimal investment levels allow employees to have the right equipment to do their job, increase employee engagement levels, minimize risk of injury and increase work satisfaction.
Public Policy Responsiveness	• Optimal investment levels allow for maximum equipment efficiencies and minimize Hydro One's environmental impact. • Ensure compliance with all codes, standards and regulations to sustainably manage our environmental footprint. • Vehicles will be maintained at an optimum level to ensure public and employee safety and to meet Ministry regulations.

Financial Performance	• Ensure savings from operational effectiveness are sustainable. • Control maintenance costs (external repair, parts and internal labour), potential rental costs and maintain equipment rates at optimal levels.

C. EXPENDITURE PLAN

Costs in the table below are the costs of the TWE Replacement Program, and are based on the Hydro One current work program, direction and strategy. The TWE Replacement program will be adjusted as required with the changing needs of the business. The costs indicated below are average unit costs as provided by the awarded manufacturer's approved contract with Hydro One (which includes escalation for future years).

Table 2 - Total Investment Cost

($ Millions)[1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	0.0	13.2	13.2	13.3	13.3	13.3	0.0	66.3
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**13.2**	**13.2**	**13.3**	**13.3**	**13.3**	**0.0**	**66.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**13.2**	**13.2**	**13.3**	**13.3**	**13.3**	**0.0**	**66.3**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown
[2] Includes Overhead at current rates.

D. ALTERNATIVES

The primary alternative to the proposed investment plan is to maintain the current TWE at its existing level. This alternative centres on a reduction in capital spending on TWE in favour of increased use of rental equipment, if available, and extended retention of existing equipment to satisfy work program and staffing requirements. Hydro One employs specialized equipment specifically outfitted to Hydro One safety specifications.

Short term rentals would be utilized where available for light duty vehicles only, as heavy duty vehicles are not readily available for rent. Historical rental usage has demonstrated that due to the challenges inherent in the nature of the work, i.e. remote and difficult to access locations and challenging weather, any savings attributable to the use of rentals are quickly offset by incremental maintenance and repairs incurred by the harsher wear and tear on the rental vehicles in this type of industry. Hydro One is responsible for the cost of the incremental maintenance and repairs on the rental vehicles. As a result of retaining existing equipment, increased maintenance and repair costs will be incurred on the retained vehicles, as older vehicles tend to have more breakdowns and require more maintenance, which will ultimately result in increased vehicle downtime and decreased equipment availability.

E. EXECUTION RISK AND MITIGATION

The TWE Replacement Program is dependent on the manufacturer’s delivery and production schedule. Manufacturing delays may result in delayed delivery of the asset in the budget year, which would result in retention of existing equipment until the new acquisition is delivered.

SA-01 Connect New IAMGOLD Mine

Start Date:	Q3 2019	**Priority:**	High
In-Service Date:	Q3 2020	**3 Year Test Period Gross Cost ($M):**	24.9
Trigger(s): Customer Request			
Outcome: Connect industrial customer to the transmission system.			

A. NEED AND OUTCOME

Investment Need

This investment is required to facilitate the request from Iamgold Corporation (“Iamgold”) to provide supply to their Cote Gold Mine near Timmins, Ontario. Iamgold is an established mining company that is planning to start a brand new “Cote” mine with expected load of approximately 70MW to be located about 40 km from Shining Tree Junction. Shining Tree Junction is an existing transmission junction 115 km south of Timmins that serves as the interconnection point between the customers’ line to Hydro One’s transmission system.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in the customer’s project receiving inadequate supply. This project has been assigned a High Priority in order to meet this customer obligation.

Investment Description

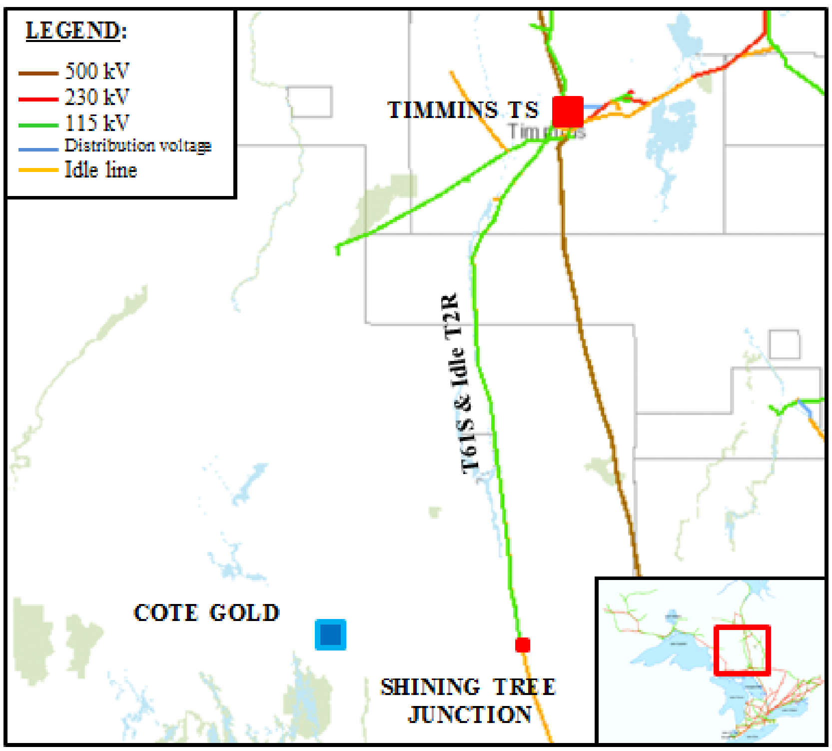
The proposed project involves providing a 115kV supply to the Iamgold Cote Gold mine from Timmins TS; including the:

- Addition of switching facilities and line termination to connect an existing idle 115kV circuit (T2R) to Timmins TS;
- Reinforcement of a 115 km section of the idle 115kV circuit (T2R) between Timmins and Shining Tree Junction;

- Installation of switching facilities at Shining Tree Junction; and
- Incorporation of the customer facility into the existing Northeast Load Rejection scheme.

Note: In conjunction with this project, Hydro One is also proposing a project to refurbish the existing 115kV transmission circuit (T61S); which shares common steel towers with the 115kV circuit (T2R) along the 115 km route from Timmins to Shining Tree Junction. This additional project for the existing 115kV transmission circuit (T61S) is described in ISD SR-20.

A map showing the project location is provided below.



The System Impact Assessment and Customer Impact Assessment were completed in 2018, and both confirm that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers.

Witness: Robert Reinmuller

Iamgold received approval from the Board in Q4 2018 with respect to its "Leave to Construct" application (EB-2018-0191) under Section 92 of the *Ontario Energy Board Act* to allow the construction of the customer line from Hydro One's Shining Tree Junction to the Cote Mine.

Hydro One has also applied for "Leave to Construct" approval (EB-2018-0257) for the reinforcement of 115kV circuit (T2R) under Section 92 of the *Ontario Energy Board Act* and initiated the Class Environmental Assessment under the *Environmental Assessment Act* in Q3 2018. A summary of the need, project description, risks, and costs have been presented in the Section 92 application. All land matters will be addressed in the Section 92 application. Hydro One is currently awaiting the Board's decision in this matter.

Commencement of the project is subject to signing of the Connection Cost Recovery Agreement ("CCRA") with the customer.

Outcomes

This investment will provide the required transmission facilities to supply power to the new Cote Gold mine, which has a projected load of 70MW.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Satisfy customer request for connection.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recoverable through capital contributions from the customer. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the project is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	10.5	24.9	0.0	0.0	0.0	0.0	0.0	35.4
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**10.5**	**24.9**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**35.4**
Less Capital Contributions	10.0	15.0	0.0	0.0	0.0	0.0	0.0	25.0
Net Investment Cost	**0.5**	**9.9**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**10.4**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

No alternative was considered, as this investment is in response to a specific customer request.

D. EXECUTION RISK AND MITIGATION

The risks with respect to execution of this investment as planned would be as a result of potential delays in securing the Section 92 and environmental assessment approvals. These risks are mitigated by initiating the Section 92 application process and environmental assessment process in a timely manner. There is also a risk that the customer requirements may change, resulting in a delay or cancellation of the need for this project. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer decides to cancel the project.

SA-02 Horner TS: Build a Second 230/27.6kV Station

Start Date:	Q4 2018	**Priority:**	High
In-Service Date:	Q4 2020	**3 Year Test Period Gross Cost ($M):**	29.9
Trigger(s): Customer Request			
Outcome: Increase transformation capacity in Southwest Toronto.			

A. NEED AND OUTCOME

Investment Need

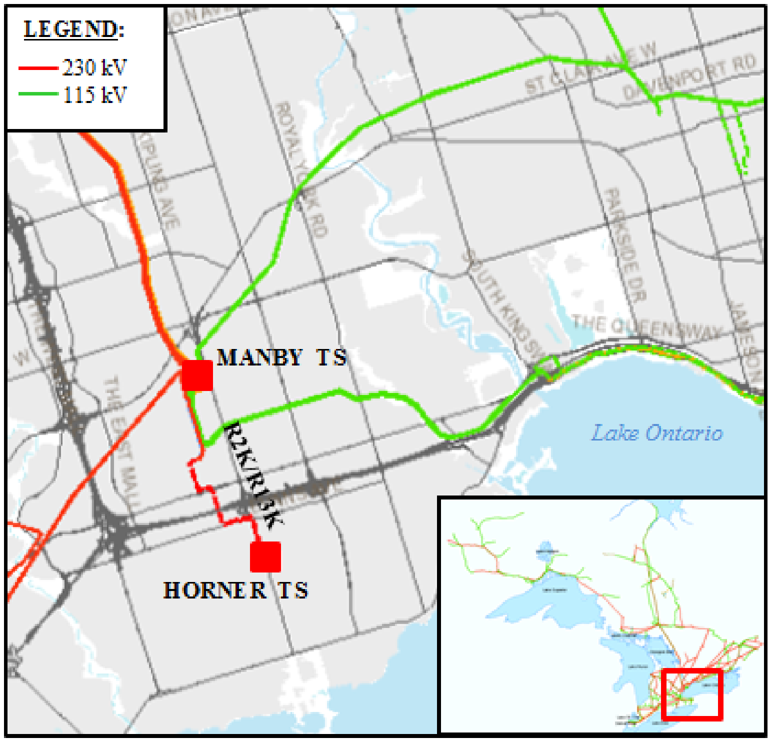
The Southwest Toronto area is supplied by two 230/27.6kV transformer stations, Manby TS and Horner TS. Based on current load forecast, the loading at these two stations is expected to exceed their combined capacity of 400MW by summer 2021. This investment is required to facilitate the request from Toronto Hydro to increase the transformation capacity to accommodate this forecast customer load growth in the Southwest Toronto area; as documented in the Metro Toronto Regional Infrastructure Plan (Exhibit B, Tab 1, Schedule 1, TSP Section 1.2, Attachment 8).

Hydro One is obligated to provide expanded facilities when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in inadequate transformation capacity to supply customer demand in the area. This project is assigned a High Priority in order to meet this customer obligation.

Investment Description

The proposed project involves the construction of a new 230/27.6kV Dual Element Spot Network ("DESN") station with two 75/125MVA transformers along with a new 27.6kV switchyard at the existing Horner TS site. The new transformer station will be supplied by the existing 230kV transmission circuits (R2K/R13K) which run between Manby TS and Richview TS. This work will increase the existing capacity at Horner TS by 170MVA.

A map showing the project location is provided below.



The System Impact Assessment for the project was completed in 2016 and confirms that the project will not adversely affect the reliability of the IESO-controlled grid. The Customer Impact Assessment process is underway and completion is anticipated in Q1 2019. The assessment also confirms that there is no adverse impact of the new facilities on other transmission connected customers.

Commencement of the project is subject to signing of the Connection Cost Recovery Agreement ("CCRA") with the customer.

Outcomes

This investment will provide the required increase in transformation capacity to supply load growth in the Southwest Toronto area.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Satisfy customer request for additional capacity.
Operational Effectiveness	• Increase capacity, and improve operational flexibility, with the addition of a second DESN.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be fully recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customer. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the project is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2022	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	21.0	29.9	0.0	0.0	0.0	0.0	0.0	50.9
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**21.0**	**29.9**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**50.9**
Less Capital Contributions	18.8	25.8	0.0	0.0	0.0	0.0	0.0	44.6
Net Investment Cost	**2.2**	**4.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**6.3**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

Two alternatives were considered for providing additional capacity in the Southwest Toronto area.

- Alternative 1: Build a new transformer station at a new site in Southwest Toronto. Acquiring a new site and building new 230kV lines to supply the new station would be required.

- Alternative 2 (Recommended): Build a second transformer station at the existing Horner TS. The existing footprint of Horner TS has sufficient space to build the new facilities and there is sufficient capacity on the existing 230kV lines at the station to supply the new transformer station.

Both Alternative 1 and 2 provide the needed capacity for the area; however, Alternative 1 would incur additional costs involved in acquiring a new site and time to obtain the necessary approvals. Therefore, Alternative 2 is the recommended alterative as it maximizes the use of existing facilities, can be executed in a timely manner and has a lower cost. This alternative is also in accordance with the recommendations of the Metro Toronto Regional Infrastructure Plan, which recommended building the second DESN at the Horner TS site.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as: outage availability that is required for the work to be executed and timely customer approval of the CCRA. These risks will be mitigated by working with the customer on setting a schedule that aligns with outage availability. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer decides to cancel the project.

SA-03 Halton TS: Build a Second 230/27.6kV Station

Start Date:	Q2 2020	**Priority:**	High
In-Service Date:	Q2 2022	**3 Year Test Period Gross Cost ($M):**	31.7
Trigger(s): Customer Request			
Outcome: Increase transformation capacity to supply the GTA West area.			

A. NEED AND OUTCOME

Investment Need

Halton TS is a 230/27.6kV transformer station supplying Halton Hills Hydro and Milton Hydro load in the Halton Region. Based on the current demand forecast, the station load is expected to exceed its capacity of 186MW by summer 2022. This investment is required to facilitate the request from Milton Hydro to increase the transformation capacity to accommodate this forecasted customer load growth in the Town of Milton, as documented in the GTA West Regional Infrastructure Plan (Exhibit B, Tab 1, Schedule 1, TSP Section 1.2, Attachment 6).

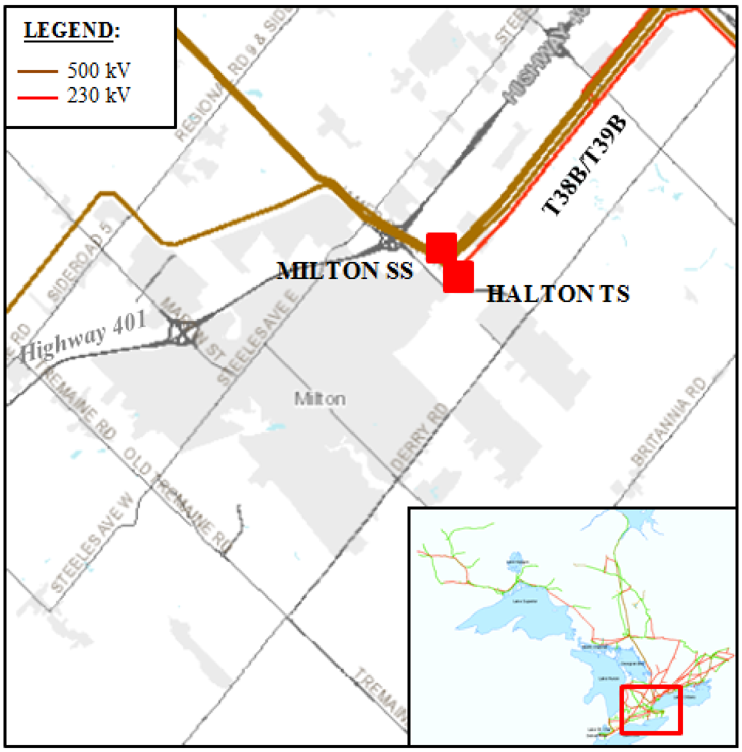
Hydro One is obligated to provide expanded facilities when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in inadequate transformation capacity to supply customer demand in the Town of Milton. This project has been assigned a High Priority in order to meet this customer obligation.

Investment Description

The proposed project involves the construction of a new 230/27.6kV Dual Element Spot Network (“DESN”) station with two 75/125MVA transformers along with a new 27.6kV switchyard at the existing Halton TS site. The new transformer station will be supplied by the existing 230kV transmission circuits (T38B/T39B) which also supply the existing Halton TS. This work will increase the existing capacity at Halton TS by 170MVA.

The proposed project is intended to provide relief for only the Milton Hydro load; as any increase in Halton Hills Hydro load will be met by the new Halton Hills Hydro MTS planned for in-service in Q1 2019.

A map showing the project location is provided below.



The System Impact Assessment and Customer Impact Assessment will be completed for the project by Q4 2019 to confirm that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers.

Commencement of the project is subject to signing of the Connection Cost Recovery Agreement ("CCRA") with the customer.

Outcomes

This investment will provide the required transformation capability to meet Milton Hydro's forecast customer load growth.

Witness: Robert Reinmuller

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Satisfy customer request for additional capacity.
Operational Effectiveness	• Increase capacity, and improve operational flexibility, with the addition of a second DESN.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the project is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	0.8	8.0	17.7	6.0	0.0	0.0	0.0	32.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.8**	**8.0**	**17.7**	**6.0**	**0.0**	**0.0**	**0.0**	**32.5**
Less Capital Contributions	0.4	6.0	14.0	6.0	0.0	0.0	0.0	26.4
Net Investment Cost	**0.4**	**2.0**	**3.7**	**0.0**	**0.0**	**0.0**	**0.0**	**6.1**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

Two alternatives were considered for providing additional capacity for Milton Hydro loads.

- Alternative 1: Transfer loads to adjacent area stations. However, the adjacent area stations either have no capacity or were located far away from the Milton Hydro load center and were ruled out due to a lack of technical feasibility. Therefore, this alternative was not considered further.

- Alternative 2 (Recommended): Build a second transformer station at Halton TS. The existing footprint of Halton TS has sufficient space to build the new facilities and there is sufficient capacity on the existing 230kV lines at the station to supply the new transformer station.

Alternative 2 is the recommended alternative as it is the lowest cost and practical alternative to provide the needed capacity. This recommended alternative is in accordance with the recommended plan in the GTA West Regional Infrastructure Plan by providing additional capacity to support the area's growth.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as: outage availability that is required for the work to be executed and timely customer approval of the CCRA. These risks will be mitigated by working with the customer on setting a schedule that aligns with outage availability. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer decides to cancel the project.

SA-04 Connect Metrolinx Traction Substations

Start Date:	Q2 2019	**Priority:**	High
In-Service Date:	Q1 2023	**3 Year Test Period Gross Cost ($M):**	21.4
Trigger(s): Customer Request			
Outcome: Connect six Metrolinx traction power substations to the transmission system.			

A. NEED AND OUTCOME

Investment Need

This investment is required to facilitate the request from Metrolinx to provide connection to six traction power substations that are required as part of the GO Transit electrification project.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in Metrolinx's inability to proceed with their electrification project. This project has been assigned a High Priority in order to meet this customer obligation.

Investment Description

Metrolinx is electrifying the GO Train rail network across the Greater Toronto and Hamilton Area as part of a multi-year project. The electrification requires the construction of traction power substations ("TPSS") to provide power along the rail corridors. Each of the Metrolinx TPSS are planned to be located adjacent to Hydro One's existing transmission circuits and will require a dual 230kV supply. The TPSS loads, with planned supply circuits, and Metrolinx's expected in-service dates are outlined in the following table.

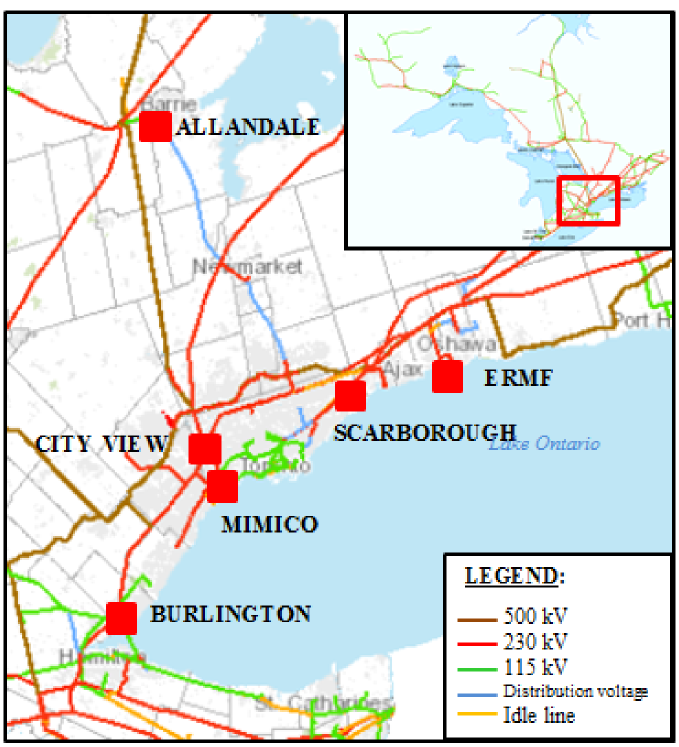
Table 1: TPSS Loads, Supply and Planned In-Service Dates

No.	Traction Power Station	MW Load	Supplied from 230kV Transmission Circuits	Required in-service date
1	Mimico	26	K21C / K23C	Q4 2021
2	Cityview	28	V73R / V77R	Q4 2021
3	Burlington	12	B40C / B41C	Q1 2022
4	Allandale	10	E28 / E29	Q1 2022
5	Scarborough	41	C2L / C14L	Q1 2023
6	East Rail Maintenance Facility	22	T24C / T26C	Q1 2023

Hydro One has set up six separate projects to cover each of the six connection requirements to these TPSS. The proposed projects involve the following:

- Construction of a dual 230kV line tap from the transmission circuits to the Metrolinx TPSS; and
- Modification of the protection and control facilities for the transmission circuits to incorporate and integrate the TPSS.

A map showing the six Metrolinx TPSS locations is provided below.



The System Impact Assessments and Customer Impact Assessments were completed for all six of the Metrolinx TPSS connection projects over the 2017 and 2018 period. The assessments confirmed that the projects will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers.

The project start for each of the TPSS connection projects is subject to signing of their respective Connection Cost Recovery Agreements ("CCRA") with the customer.

Outcomes

This investment will facilitate electrification of the GO Transit rail network by providing the required electric supply to Metrolinx TPSS.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Satisfy customer requests for connection.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License and Transmission System Code to provide customers with non-discriminatory access. • Support Provincial GO Regional Express Rail Initiative.[1]

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be fully recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customer. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the project is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

[1] *https://news.ontario.ca/mto/en/2017/06/ontario-taking-major-step-forward-to-electrify-the-go-rail-network.html*

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	1.4	6.5	7.9	7.1	1.0	0.0	0.0	23.8
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**1.4**	**6.5**	**7.9**	**7.1**	**1.0**	**0.0**	**0.0**	**23.8**
Less Capital Contributions	1.0	3.6	5.0	3.5	0.0	0.0	0.0	13.0
Net Investment Cost	**0.4**	**2.9**	**2.9**	**3.6**	**1.0**	**0.0**	**0.0**	**10.7**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

No alternative was considered, as this investment is in response to a specific customer request. Each connection was reviewed to provide the lowest cost connection possible.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as: outage availability that is required for the work to be executed. These risks will be mitigated by working with the customer on setting a schedule that aligns with outage availability. There is also a risk that the customer requirements may change resulting in a delay or cancellation of the need for this project. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer decides to cancel the project.

SA-05 Future Transmission Load Connection Plans

Start Date:	Program	**Priority:**	High
In-Service Date:	Program	**3 Year Test Period Gross Cost ($M):**	29.8
Trigger(s): Customer Request			
Outcome: Respond to future requests to connect transmission customers.			

A. NEED AND OUTCOME

Investment Need

This investment is required to enable Hydro One to accommodate future requests from load customers to connect to Hydro One's transmission system for which the need and scope have yet to be determined. This investment anticipates load customer requests that are currently unknown, but are expected to arise, during the test period.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. This investment has been assigned a High Priority to ensure customer future needs are addressed in a timely manner.

Investment Description

This investment has been set up to cover future load connection projects anticipated in the test period; for which the need and scope have not yet been identified at this time. Each project would be initiated based on the customers' requirements for capacity and/or reliability improvements. A project may also be initiated by regional planning needs or to address end-of-life facilities.

Load customer connections are typically addressed by providing new or modified transformation and/or line connection facilities. Each investment would be specific to the customer needs. Based on past customer requests, the requested investments may require Hydro One to construct one or more of the following:

- New feeder positions at existing transformer stations;
- New or modified transformation facilities at existing transformer stations;
- New connection lines; and/or
- New transformer stations.

Commencement of each project will be subject to signing of the Connection Cost Recovery Agreement ("CCRA") with the customer and obtaining all necessary regulatory and environmental approvals, as applicable.

Outcomes

This investment will address specific customer requests for connection or transformation capacity to supply the customers' forecasted load growth.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Satisfy customer requests for additional capacity.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, have been forecasted based on typical costs incurred by load connections over the past five year period. The project costs will be fully recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customer(s), determined on a project-by-project basis in accordance with the Transmission System Code. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the project is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

The projects' actual in-service costs would be included in the rate base when the projects go into service, subject to Board approval. For any projects that require “Leave to Construct” approval under Section 92 of the *Ontario Energy Board Act*, prudency of the expenditures will be tested during the Section 92 process.

Table 1 - Total Investment Cost

($ Millions)	2020	2021	2022	2023	2024	Total[1]
Capital[2] and Minor Fixed Assets	0.0	5.0	24.9	24.9	0.0	54.7
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**5.0**	**24.9**	**24.9**	**0.0**	**54.7**
Less Capital Contributions	0.0	2.0	18.0	16.0	0.0	36.0
Net Investment Cost	**0.0**	**3.0**	**6.9**	**8.9**	**0.0**	**18.7**

[1] *Due to the in-year nature of program investments, only 2020 to 2024 expenditures are shown.*
[2] *Includes Overhead at current rates.*

C. ALTERNATIVES

This investment will be in response to a specific customer(s) request received in the future; alternatives (if any) will be reviewed with the customer(s) as part of the connection assessment process.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as: outage availability that is required for the work to be executed and timely customer approval of the CCRA. These risks will be mitigated by working with the customer on setting a schedule that aligns with outage availability. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer decides to cancel the project.

SA-06 Protection and Control Modifications for Distributed Generation

Start Date:	Program	**Priority:**	High
In-Service Date:	Program	**3 Year Period Gross Cost ($M):**	9.6
Trigger(s): Customer Request, Reliability			
Outcome: Allow connection of distributed generation.			

A. NEED AND OUTCOME

Investment Need

This investment is needed to perform the necessary protection and control upgrades on the transmission system to preserve its loading and protection capability in order to accommodate the distributed generation connections on Hydro One's distribution system. Distributed generation are generators that connect to the distribution system and these connections may require modifications to the transmission protection system in order to maintain a safe and reliable operation of the transmission system.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in new distributed generation resources not being able to connect. This program is assigned a High Priority in order to meet mandated obligations to customers.

Investment Description

There are a variety of generation procurement programs organized by the IESO to encourage new distributed generation connections, such as: the Large Renewable Program, the Combined Heat and Power Standard Offer Program, and the Energy Storage Procurement Program. Hydro One Distribution continues to receive requests from distributors and individual generation customers to connect distributed generation. In order to accommodate the connection of generation to the distribution system, Hydro

One's transmission system requires protection and control systems modifications and/or additions in the transmission stations to ensure proper protection of transmission assets, reliability of supply to the distribution systems, and a safe interconnection for the distributed generators.

The proposed program involves, but is not limited to, the following protection and control modifications and/or additions:

- Feeder Protection Replacement to preserve the protection capability of the feeders and provide directioning in order to prevent false tripping;
- Bus Protection Modification to prevent mis-operation;
- Line Back-up Protection Installation to protect transmission assets from distributed generators' fault current contribution;
- Transfer Trip Signalling Installation to prevent distributed generation islanding and to coordinate with reclosing and restoration;
- Station Telecom Facilities Installation to enable transfer trip signaling; and
- Station Telemetry Expansion to provide feeder telemetry and additional equipment alarms.

Commencement of each project is subject to signing of the Connection Cost Recovery Agreement ("CCRA") with the customer(s).

Outcomes

This investment will provide the required connection of distributed generation throughout Ontario without compromising system reliability, by maintaining proper protection and loading capability of the transmission assets.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Satisfy customer requests for connection of distributed generation to Hydro One's distribution system.
Operational Effectiveness	• Preserve the loading and protection capability of the transmission system while incorporating renewable generation.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.

B. EXPENDITURE PLAN

This investment is non-discretionary. The program costs, as presented in the table below, will be fully recoverable through capital contribution from the customers. The gross costs have been forecast based on current generation customer requests, and anticipated future requests resulting from the IESO's generation procurement programs. The program costs and capital contribution amounts are considered preliminary as they are only finalized once the project is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 1 - Total Investment Cost

($ Millions)	2020	2021	2022	2023	2024	Total[1]
Capital[2] and Minor Fixed Assets	3.8	3.1	2.7	2.8	2.8	15.2
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**3.8**	**3.1**	**2.7**	**2.8**	**2.8**	**15.2**
Less Capital Contributions	3.8	3.1	2.7	2.8	2.8	15.2
Net Investment Cost	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

[1] *Due to the in-year nature of program investments, only 2020 to 2024 expenditures are shown.*
[2] *Includes Overhead at current rates.*

C. ALTERNATIVES

No alternative was considered, as failure to implement the protection and control modifications and/or additions would result in the inability to respond to connection requests. Required modifications will be determined on a project-by-project basis.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as: outage availability that is required for the work to be executed and timely customer approval of the CCRA. These risks are mitigated by working with customers on setting a schedule that aligns with outage availability. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer(s) decide to cancel the project.

SA-07 Secondary Land Use

Start Date:	Program	**Priority:**	High
In-Service Date:	Program	**3 Year Test Period Cost ($M):**	2.9
Trigger(s):	Third Party Request		
Outcomes:	Relocation and/or modification of Hydro One's transmission facilities to accommodate third party requests.		

A. NEED AND OUTCOME

Investment Need

This investment is required to facilitate requests from third parties for the relocation, removal, or reinforcement of transmission assets in response to project proposals, such as: roadwork, transit systems, and other major infrastructure or development work that may encroach upon or impact Hydro One assets and rights-of-ways.

The Province of Ontario has established a Provincial Secondary Land Use Program that allows for the use of corridors, while recognizing the primary use of the lands is for electricity infrastructure. This investment has been assigned a High Priority given Hydro One's obligations and the requirements to this broad group of stakeholders, including: municipalities, third-party developers, pipeline companies, Metrolinx and the Ministry of Transportation Ontario ("MTO").

Investment Description

The proposed program involves accommodating third party requests to utilize Hydro One's transmission corridors for secondary land-use purposes. Hydro One may require additional or modified land rights to accommodate the request. In these cases, the proponents will acquire the additional land rights on Hydro One's behalf.

The material projects planned over the plan period, including the estimated costs and details relating to each identified project, are outlined in Table 1 below. The most common investment drivers are: municipal and regional transit planning, highway expansions and development projects adjacent to or crossing Hydro One's right of way.

Table 1 - List of Material Projects

No	Project Name	Description	Total Gross ($M)
1	**Burlington Beach Line Relocation** *Customer: Region of Halton*	The Region of Halton ("*Region*") and the City of Burlington are preparing a Community Plan. The Region has expressed an interest in transforming a portion of Burlington Beach into a waterfront park consistent with the vision for the area outlined in its official plan. This development would encroach on Hydro One's existing structures supporting circuits serving the western Greater Toronto and Hamilton Area and Golden Horseshoe. The Region has inquired about the feasibility of relocating or modifying the affected circuits. If the project proceeds, the structures on the Burlington TS by Beach Road Junction right-of-way would be modified.	**22.0**
2	**Manvers - Lafarge Aggregate Pit** *Customer: Lafarge*	Four of Hydro One's 230kV transmission circuits (H24C, H26C, C28C, and M29C) cross through Lafarge's aggregate pit located in the Clarington and Kawartha Lakes region. These transmission lines extend across the operating pit—a distance of about 14 circuit km. Over the years, aggregate excavation has left several of these circuit towers islanded atop 100 feet high pedestals of land. Lafarge has expressed interest in excavating the material beneath these towers. To accommodate this proposal, Hydro One must relocate these structures.	**12.3**
3	**Metrolinx – Don Yard Relocation** *Customer: Metrolinx*	Metrolinx has announced improvements to the Union Station Go rail corridor that includes an upgrade and expansion of the Don Yard facility. To accommodate Metrolinx's planned development, Hydro One must relocate the 115kV transmission circuits (H9EJ/H10EJ) and the 115kV underground cable (H2JK).	**15.0**

No	Project Name	Description	Total Gross ($M)
4	**Metrolinx - Caledonia GO Station Modification** *Customer: Metrolinx*	Metrolinx has identified improvements to its Barrie GO rail corridor (near Eglinton Avenue West and Croham Road in Toronto) that includes the expansion to the rail corridor from one track to three tracks, and the addition of a new GO station with two pedestrian platforms. To accommodate Metrolinx's planned development, Hydro One must relocate or bury the 115kV double-circuit line (K1W/K3W) that is located within the rail corridor.	**15.3**
5	**Metrolinx – Electrification** *Customer: Metrolinx*	Metrolinx has proposed the installation of new overhead catenary systems ("OCS") along all rail corridors owned, operated or serviced by Metrolinx. The OCS conflicts with existing Hydro One assets at multiple locations along the rail corridor. To accommodate Metrolinx's planned development, Hydro One must address these OCS conflicts which will require mitigation prior to the end of 2020.	**16.7**
6	**Ottawa LRT** *Customer: City of Ottawa*	The City of Ottawa is implementing a light rail transit system. One proposed alignment presents the following two potential conflicts with Hydro One's transmission assets: • <u>Trim Road</u>: Grade separation of Trim and Ottawa Road 174 intersections, including: two bridge structures, access and egress ramps, conflict with existing 115kV transmission line (H9A). • <u>Lincoln Fields</u>: The proposed LRT alignment conflicts with underground cables (F10MV and C7BM). To accommodate this proposal, Hydro One will require modification of the 115kV transmission line (H9A) to allow for appropriate clearances to the structures; and relocation of the 115kV underground cables (F10MV and C7BM).	**17.6**
7	**Thunder Bay - Hwy 11/17-Pearl Lake** *Customer: MTO*	The MTO has identified plans to realign and widen a 14.4km section of Highway 11/17 in the Municipality of Shuniah (near Thunder Bay). MTO's proposal will impact Hydro One's 115kV transmission circuits (A7L/R1LB and A6P). To accommodate this proposal, Hydro One must modify and/or relocate several transmission structures on the affected lines.	**12.4**

Note: The Total Gross includes the total cost of the project, including any costs prior to the test years, if applicable.

Outcome

These investments will allow Hydro One to fulfill its obligations in accommodating the development work of customers and other third parties, while also ensuring public safety is maintained with respect to the siting and operations of affected Hydro One transmission assets.

The following table summarizes the anticipated outcomes of the investment:

Customer Focus	• Satisfy the proposed project-related requirements of customers and third parties.
Operational Effectiveness	• Maintain sufficient clearances to Hydro One transmission assets to ensure public safety.
Public Policy Responsiveness	• Support provincial secondary land use policies through the relocation and/or modification of transmission facilities to accommodate compatible uses.

B. EXPENDITURE PLAN

This investment is non-discretionary. The program costs, as presented in the table below, will be mainly recoverable through capital contributions from the customers. The size and complexity of these projects vary from year to year; the forecast is based on preliminary estimates for the projects which are in various stages of development.

Table 2 - Total Investment Cost

($ Millions)	**2020**	**2021**	**2022**	**2023**	**2024**	**Total[1]**
Capital* and Minor Fixed Assets	55.1	15.0	13.9	15.6	3.9	103.4
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**55.1**	**15.0**	**13.9**	**15.6**	**3.9**	**103.4**
Less Capital Contributions	54.2	13.7	13.1	14.8	3.1	98.9
Net Investment Cost	**0.9**	**1.3**	**0.8**	**0.8**	**0.8**	**4.4**

[1] *Due to the in-year nature of program investments, only 2020 to 2024 expenditures are shown*
[2] *Includes Overhead at current rates.*

C. ALTERNATIVES

Hydro One works with third parties that propose secondary land uses and assesses whether the proposals are technically compatible with the safe and reliable operation of Hydro One's transmission infrastructure. Some proposals are deemed to be incompatible and do not proceed. For those proposals that are compatible and consistent with Provincial Secondary Land Use principles, no alternative was considered, as this investment is in response to specific customer and third party requests. However, each investment is scoped, planned and executed to provide the lowest cost relocation or modification possible, given the nature of existing infrastructure.

D. EXECUTION RISK AND MITIGATION

Certain normal project execution risks may affect the timely completion of each project, such as: the outage availability that is required for the work to be executed, delays in securing regulatory approvals, and timely customer approval of the Connection Cost Recovery Agreement ("CCRA"). These risks are mitigated by working with customers on setting a schedule that aligns with availability. These investments are also demand-driven and susceptible to delays, cancellations and scope changes driven by external factors that are beyond Hydro One's control. Ongoing coordination and engagement, as well as structured capital cost recovery agreements mitigate the risk of investment uncertainty in the event of scope changes or cancellation. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer decides to cancel the project.

SR-01 Air Blast Circuit Breaker Replacement Projects

Start Date:	Q4 2013	**Priority:**	High
In-Service Date:	Q4 2027	**3 Year Test Period Cost ($M):**	366.2
Triggers: Strategic, System Renewal, Customer Engagement			
Outcome: Increase reliability and performance to large customers and generators; improve reliability to the BES, stage approach to minimize customer outages, reduce maintenance cost associated with End of Life ("EOL") equipment and air systems, reduce constrained power flow through the station; replace EOL PCT equipment; reduce costs of unplanned outages due to ABCB failures and leaking air systems.			

A. OVERVIEW

Air Blast Circuit Breaker Replacement Project (the "Project") involves the replacement of Air Blast Circuit Breakers ("ABCBs") and their auxiliary station equipment that are at a high risk of failure due to deteriorated condition and asset obsolescence. The principal drivers of the Project are unacceptable reliability performance, high operation and maintenance costs and unavailability of spare parts and technical support due to obsolescence. The majority of installed ABCBs have surpassed their EOL and the entire population of ABCBs will exceed their expected service life by the end 2023 if proactive replacements are not undertaken. Currently, the obsolescence of ABCBs, which were originally installed in the 1970s, already pose significant challenges in terms of the high operating costs required to maintain system reliability. The lack of available spare parts due to the obsolescence of the technology further constrains Hydro One's ability to maintain these assets and implicitly the resulting system reliability at the appropriate level. Almost half of Hydro One's ABCBs population is installed at critical stations that are delivery points to hydraulic, gas and nuclear plant operators and interties. Any forced outages at the critical stations due to ABCB failures would adversely impact these sensitive customers, who have expressed the view that a high level of reliability is paramount to their operations. To address customer concerns, high risk to reliability performance of deteriorated ABCB assets, and associated escalating maintenance costs, Hydro One evaluated several alternatives, as described below, and concluded that the targeted replacement of ABCBs, whose condition have been rated as a high or very high risk, is a prudent and preferred alternative. The projected cost of the Project is estimated to be $366.2 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

ABCBs were developed in the 1950's to solve the technical limitations that oil circuit breakers could not overcome. ABCBs rely on complex mechanical and pneumatic subsystems for proper operation. Between 1950 and 1982, the former Ontario Hydro (predecessor of Hydro One) installed 278 High Voltage ("HV") (i.e., 115 kV and above) and 10 Medium Voltage ("MV") (i.e. 44 kV and below) ABCBs. Since the time of installation, 148 HV and 5 MV ABCBs have been replaced as a result of various control components issues such as air leaks, operating mechanism issues, moisture content problems and auxiliary equipment malfunctions. Hydro One's typical practice is to repair the breakers where issues (e.g. air leaks) have been identified. However, Hydro One's fleet of ABCBs is no longer supported by vendors and as such, it is extremely difficult to obtain technical support and spare parts which are either no longer available or are costly to acquire or fabricate. For example, ABCBs require high pressure air systems that consist of compressors, holding tanks and extensive piping. These systems cause Hydro One to incur $3 million in annual maintenance costs.

The high pressure air system is highly susceptible to air leaks that cause outages. Severe air leaks are a significant concern for the ABCB fleet as large groupings of breakers are supplied by a common airline. Maintaining high pressure air systems increases the Operations, Maintenance & Administration ("OM&A") cost by approximately $15 thousand per air blast breaker. In the winter months, issues with air pressure and safety valves freezing in the open position lead to the loss of air and the loss of breaker control. This can result in the removal or isolation of multiple adjacent breakers and high voltage circuits, thereby causing large load interruptions and generation bottling. For example, in winter 2017, after experiencing pressure loss on the air system due to low temperatures, multiple HV breakers were forced out of service at Cherrywood TS in the 230kV switchyard, thereby constraining generation capacity and power flow throughput.

The average age of the ABCBs population installed on Hydro One's transmission system is 46.5 years, surpassing the manufacturer's specified service life of 40 years. As part of the asset condition assessment, Hydro One rated the entire population of ABCBs at a high or very high risk. This assessment is based on the factors such as internal condition diagnostics, performance, criticality, obsolescence and economics. Hydro One performs internal condition diagnostics (Level 1 and Level 2 diagnostic testing) where it gains condition data on the breakers via micro-ohm measurement and timing tests. In accordance with Hydro One performance records, ABCBs are the highest risk breaker population in Hydro One's transmission system. Circuit breaker performance is measured by assessing the number of forced outages due to some inherent failure of the breaker itself. A "forced outage" is the automatic or forced manual removal of high voltage breakers caused directly by the breaker itself or terminal equipment directly adjacent to the breaker. Typical ABCB failure modes have included control components issues, air leaks, operating mechanism issues, moisture content problems and auxiliary equipment malfunctions. The number of forced outages due to ABCB failure has significantly increased over the past ten years as shown in Figure 1 below. This increasing trend is due to known air system issues caused by deteriorated O-rings (as described above), valves and problems with control components.

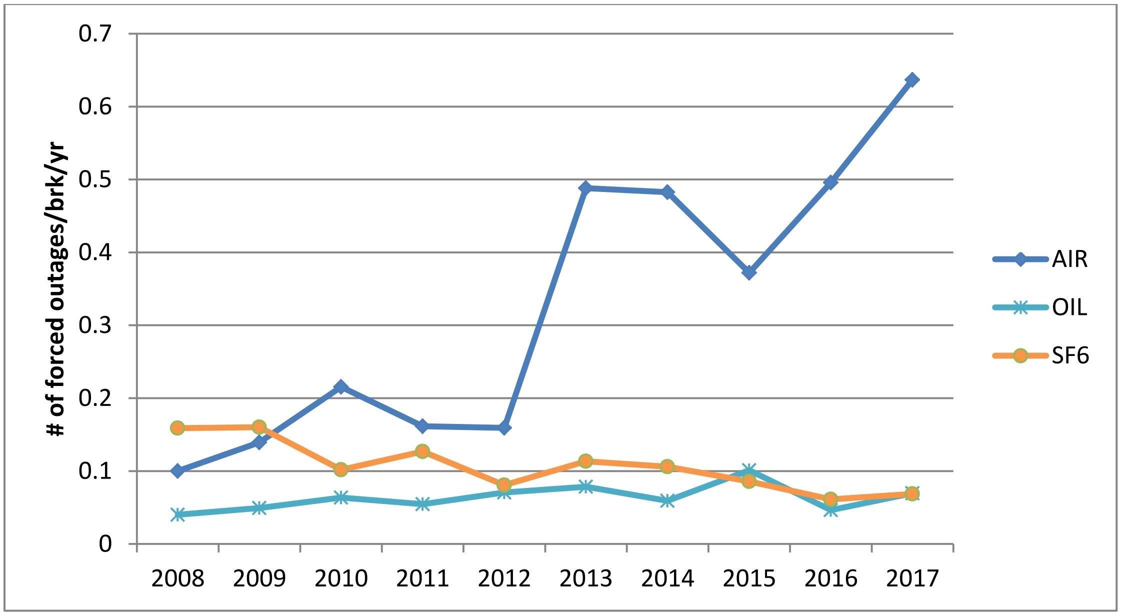


Figure 1 - Circuit Breaker Forced Outage Duration by Breaker Type

As of December 31, 2018, 47% of the remaining ABCBs are installed at critical transmission stations as presented in Table 1 below.

Table 1 - Generators connected through Hydro One stations with ABCBs

Hydro One Station	Connected Generator(s)	Generator Capacity (MW)
Bruce A TS	Bruce A GS	3,116
Bruce B SS	Bruce B GS	3,268
Cherrywood TS	Pickering GS	3,100
Lennox TS	Lennox GS	2,100
Sir Adam Beck I SS	Sir Adam Beck I GS	450
Sir Adam Beck II TS	Sir Adam Beck II GS Sir Adam Beck Pump GS	1,499 174
Total:		**13,707**

These critical transmission stations support major nuclear and hydraulic generation plants as well as connect international power flow to the states of New York and Michigan.

Forced outages at these critical stations, attributed to ABCBs, have a significant impact on customers. In the case of nuclear generating plants, the outages have caused supply interruptions to the station service transformers or in other cases, the outages have caused the loss of production. For example, in 2016, Sir Adam Beck II had a loss of 6 ABCBs which resulted in 100 MW of reduced generation, impacting the imports and exports of power to the New York Power Authority (NYPA) and the customer, Ontario Power Generation (OPG) had to redirect the river water flow to avoid flooding parts of downtown Niagara Falls.

Further, the major bulk transmission stations are subject to special considerations in accordance with Section 5.7 of the IESO's Ontario Power System Restoration Plan ("OPSRP"). The OPSRP is the required operating procedure for the IESO and the restoration participants, such as Hydro One, to restore the power system and mitigate the emergency in the event of a partial or complete blackout. The majority of the bulk stations listed in OPSRP are still operating through ABCBs. As such, Hydro One is required, pursuant to section 5.7.3 of the OPSRP, to pre-determine the air system's ability to support multiple breaker operations, adopt operating procedures to monitor for problems and to mitigate any identified shortfalls in capability. Extensive OM&A cost is needed to maintain current deteriorated high pressure air systems in these stations. (e.g., use of a diesel generator).

The higher cost and difficulty associated with maintenance requirements when compared to newer technology, the unavailability of spare parts due to obsolescence, and the lack of technical support to work on the deteriorating population of installed ABCBs lead to longer outage times associated with both routine and emergency maintenance. This is problematic for Hydro One and its customers from both a cost and service-reliability perspective. In order to address all of these issues, Hydro One is required to proceed with this Project and, as such has assigned it a high priority.

Investment Description

The Project involves a series of individual projects at various transformer stations. Each ABCB replacement project will vary in size and scope and will include some or all of the following: the replacement of ABCBs, removal of the high pressure air system, upgrade AC and DC systems, protection, upgrades to control and telecom systems, upgrades to high risk station ancillary equipment, site or property upgrades, customer triggered upgrades as well as upgrades driven by safety concerns, environmental compliance and operational issues. Cumulatively, the Project targets the replacement of 132 ABCBs and their auxiliary station equipment at ten transformer stations (95 during the planning period), as further detailed in Appendix “A” below.

The level of investment has been determined based on the assessment of ABCBs condition and in consideration of customer preferences, safety concerns, compliance requirements and Hydro One’s ABCBs strategy. An Asset Management Strategy to effectively manage numerous risks associated with this aging breaker population recommends the replacement of ABCBs within the bulk electric system before or at the age of 50 years old due to, among others, performance and reliability issues as well as the maintenance costs. Due to the significant impact that ABCBs have on the provincial transmission system and international tie-line connections, Hydro One actively engages with the IESO to review the scope and timing of the proposed replacement projects.

Outcome

As a result of the Project, Hydro One will improve system reliability by reducing the frequency and duration of outages caused by failed ABCBs. The Project will result in reduced operational risks associated with the operation of end-of-life equipment. Hydro One will reduce it operating costs associated with ABCBs and reduce maintenance costs associated with high pressure air systems. The Project will also assist Hydro One in ensuring compliance with the North American Electric Reliability Corporation (“NERC”) and the Northeast Power Coordinating Council (“NPCC”) requirements.

The following table presents anticipated benefits as a result of the Project in accordance with the Ontario Energy Board's ("OEB") Renewed Regulatory Framework ("RRF"):

Outcome Summary:

Customer Focus	• Improve system reliability by reducing the frequency and duration of the outages due to high risk, obsolete and EOL equipment, which are particularly vulnerable to failures during extreme cold weather • Staged approach to minimize customer outages
Operational Effectiveness	• Reduce operational risks associated with the operation of EOL equipment • Improve reliability to the bulk electric system • Reduce constrained power flow through the station which results in less redundancy
Public Policy Responsiveness	• Replace EOL PCT equipment to comply with NERC and NPCC requirements for redundant and physical separation
Financial Performance	• Reduce operating and maintenance costs associated with EOL equipment and air systems • Realize cost savings by addressing multiple deteriorating components within the station as part of the same project

C. EXPENDITURE PLAN

As discussed above, the Project involves the replacement of ABCBs and their auxiliary station equipment that are at a high risk of failure due to deteriorated condition and asset obsolescence. Hydro One planned the Project in a way that strives for completion as effectively and efficiently as possible to minimize the cost of performing this sustainment task. As part of this optimization, Hydro One will not only replace the ABCBs, but will address replacement of all other deteriorated assets, upgrade Protection, Control and Telecom equipment to the latest industry standards and improve reliability and operability of system within each investment.

Table 2 below summarizes historical and projected spending on the aggregate project level. The "Previous Years" costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	464.9	112.0	133.6	138.8	133.7	101.8	104.9	1,189.5
Less Removals	31.6	4.5	5.2	5.3	4.5	3.1	3.3	57.5
Gross Investment Cost	**433.3**	**107.5**	**128.4**	**133.5**	**129.2**	**98.7**	**101.5**	**1,132.1**
Less Capital Contributions	1.0	1.6	1.5	0.1	0.0	0.0	0.5	4.6
Net Investment Cost	**432.3**	**105.9**	**126.9**	**133.4**	**129.2**	**98.7**	**101.0**	**1,127.4**

[1] *Includes overhead at current rates.*

Table 3 below presents the projected costs on an individual project basis. It also provides the total cost, which includes costs incurred in previous years and forecasted beyond 2024, where applicable, for each individual project along with the proposed in-service date.

Table 3 - Detailed Total Project Costs

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
Richview TS	2.5	0.0	0.0	0.0	0.0	2.5	94.9	2020
Bruce A TS 230kV	6.3	0.1	0.0	0.0	0.0	6.5	111.2	2020
Beck #2 TS 230kV	12.4	11.6	8.9	0.3	0.0	33.1	110.2	2022
Middleport TS	27.3	22.6	11.2	12.9	1.9	76.0	104.6	2023
Nanticoke TS	13.4	17.1	14.8	9.3	0.9	55.6	59.4	2023
Cherrywood TS 230kV	17.2	13.4	13.8	4.2	0.0	48.6	88.9	2023
Lennox TS	5.9	4.6	5.8	2.0	0.0	18.3	88.1	2023
Bruce B SS 500kV	12.9	16.6	20.1	18.4	10.5	78.5	85.5	2024

Bruce A TS 500kV	3.7	21.0	21.9	38.0	38.6	123.2	147.3	2025
Essa TS	0.5	6.6	20.3	13.9	14.2	55.5	71.4	2025
Beck #1 SS 115kV	3.3	2.9	3.5	3.5	3.0	16.2	30.7	2026
Cherrywood TS 230kV/500kV	0.4	10.4	13.2	26.6	29.5	80.1	135.2	2027
Net Investment Cost	**105.9**	**126.9**	**133.4**	**129.2**	**98.7**	**594.0**	**1127.4**	

The factors influencing the cost of the Project include:

- The circuit breaker voltage level and the number of ABCB replacements – the higher the voltage levels the higher the cost of equipment needed. Higher voltage levels require additional space requirements due to increased electrical clearances, more structures and etc.
- The station design and configuration - foundation/structural replacements, in-situ or Greenfield replacement. Safety by design based on latest Hydro One standards (i.e. new clearance requirements, Arc Flash requirements and etc.)
- NERC and/or NPCC requirements require physical separation and redundancy
- Outage availability, and reduced contingency concerns customers. Outage availability is more difficult to achieve at nuclear facilities due to stricter contingency planning (N-2 contingency).
- By-pass construction where needed to minimize customer impacts. In many situations, to avoid constraining generation and power flow, additional by passes are required; these are costly to install and are typically removed at the end of the project (i.e. between $3 million and $5 million)

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: Reactive Component Replacement is a "Do Nothing" alternative and is based on reactive response as the failures occur, and replacing ABCB sub-components as and where needed. Hydro One rejected the "Do Nothing" alternative for the following reasons:

- Reactive management of ABCBs at critical transformer stations would decrease reliability of the 500kV, 230kV, and 115kV transmission networks and international tie-line connections by increasing outage durations to facilitate emergency repairs. Increased frequency and duration of outages could impact connected customers, increase OM&A cost due unplanned corrective work, and the air system must be maintained until all ABCBs are replaced.
- This result would be contrary to the clear preferences of the relevant customers.
- Reactive replacement would be limited to addressing failed sub-components and would not address other deteriorated sub-components with a similar risk of failing. Reactive repairs would result in increasing OM&A costs as the frequency of outages increase as presented in the Transmission System Plan ("TSP") Exhibit 2.2.1.2.
- Should a major failure occur, like-for-like replacement of the entire breaker would not be possible in many cases due to the unavailability of spare units. Replacement with a modern SF6 circuit breaker, requiring additional time for design, construction, and commissioning, would prolong the outage thereby impacting system reliability and customer satisfaction if done on a reactive basis.

Alternative 2: Switchyard Rebuild is based on rebuilding the entire ABCB switchyard in a new location (Greenfield) using modern SF6 breakers instead of replacing only assets in need of replacement by installing them in new locations within station property (Brownfield). This alternative has been rejected as Greenfield construction will be more costly due to the expansion of the existing station property, real estate acquisition (if required) and potential reconfiguration of the existing switchyard connections. While the construction of a new switchyard in a Greenfield location will minimize outage constraint and availability, these benefits do not offset the additional costs. For example, at Beck 2, Hydro One performed a comparison between Brownfield and the percent difference for Greenfield came out to 70% more.

Due to the significant cost difference Hydro One's typical direction is to carry out an in-situ replacement unless in-situ replacement is not feasible.

Alternative 3: Planned In-Situ Replacements is the preferred undertaking. This alternative is based on replacing ABCBs and auxiliary systems within the same station footprint using modern SF6 breakers. SF6 is the predominant insulating medium in the industry; possessing the highest dielectric strength of any known gas, excellent arc extinguishing and quenching capabilities, thermal stablity, and superior heat transfer properties. This alternative has been selected as the preferred alternative for the following reasons:

1. In-situ replacement resolves all of the challenges facing the ABCB fleet described above by increasing system reliability in the most cost effective manner. It aligns with the needs of Hydro One's customers and Hydro One's ABCB strategy to resolve current ABCB performance challenges.
2. The preferred alternative, unlike the "Do Nothing" alternative, proactively addresses and paces replacements without jeopardizing system reliability and customer supply points. Unlike Alternative 2, the preferred alternative results in a more cost effective solution since most real-estate and station reconfiguration challenges are avoided.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of bulk station transformer replacement projects are: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges and/or regulatory approvals. A thorough risk assessment workshop is performed during the initial project planning phase where all known risks are identified and a mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize the loss of supply to the customer. The plan may include switching a customer to an alternative supply, the construction of a temporary by-pass circuit or supplying portable generation that will maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. As another example, to allow for early identification of real estate issues, Hydro One involves real estate from project inception. The aim is to identify issues such as missing or inadequate land rights, so that Hydro One can try to resolve them prior to execution of the project.

1 **APPENDIX A – DETAILED TOTAL PROJECT PLAN**

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Station Name	Scope	Number of Remaining Air Blast Circuit Breakers to be Replaced	In Service Year
Richview TS	In-situ replacement of twenty four 230 kV ABCBs and associated switches as well as Protection & Control ("P&C") system upgrades and associated EOL assets replacements.	5	2020
Bruce A TS	Bay by bay replacement of sixteen 230 kV ABCBs and associated switches as well as P&C system upgrades and other EOL assets replacements.	7	2020
Beck #2 TS	In-situ replacement of twenty 230 kV ABCBs and associated switches, as well as P&C system upgrades and other EOL asset replacements. Eighteen breakers remain to be replaced	18	2022
Middleport TS	Replacement of twenty-one 230 kV ABCBs, their associated switches, two auto-transformers, two under-rated 500 kV SF6 breakers, P&C system upgrades and other EOL asset replacements	21	2023
Nanticoke TS	In-situ replacement of eight 500kV ABCBs and associated switches with possible bus reconfiguration, as well as P&C system upgrades and other EOL assets replacements.	8	2023
Cherrywood TS	Replacement of twelve 230 kV ABCBs and associated switches, 230 kV and 500 kV switchyard AC system upgrade, 230 kV switchyard DC system upgrades, P&C system upgrades and other EOL asset replacements	12	2023
Lennox TS	In-situ replacement of six 500 kV and eight 230 kV ABCBs and associated switches as well as P&C system upgrades and other EOL asset replacements.	14	2023
Bruce B SS	Replacement of ten 500 kV ABCBs, P&C system upgrades and other EOL asset replacements.	10	2024
Bruce A TS 500kV	Replacement of nine 500 kV ABCBs and associated switches, P&C system upgrades and other EOL asset replacements.	9	2025

Station Name	Scope	Number of Remaining Air Blast Circuit Breakers to be Replaced	In Service Year
Essa TS	Replacement of six 500 kV ABCBs and associated switches, P&C system upgrades and other EOL asset replacements. Potential to merge Development project to connect 230 kV line to Essa and eliminate an auto-transformer.	6	2025
Beck #1 SS	Replacement of two 115 kV ABCBs, rebuilding of the existing main bus on the 9th floor of the power house, the addition of a new ring bus on the 4th floor to facilitate future maintenance and operation, line connection upgrades to facilitate two new generation connections, P&C system upgrades and other EOL asset replacements	2	2026
Cherrywood TS 230kV/500kV	Replacement of fourteen 230 KV breakers, six 500 KV ABCBs and associated switches and elimination of two 230 kV breakers (due to Pickering GS shutdown), 500 kV switchyard DC system upgrade, P&C system upgrade and other EOL asset replacements	20	2027

SR-02 Station Reinvestment Projects

Start Date:	Q2 2015	**Priority:**	Medium
In-Service Date:	Q4 2025	**3-year Test Period Cost ($M):**	352.9
Trigger(s):	Strategic, System Renewal		
Outcomes:	Maintain reliability performance of bulk electricity system power flows through the replacement of end of life equipment. Maintain reliable power delivery at load supply stations. Improve the operational effectiveness of bulk and load supply stations through reconfiguration and standardization of new equipment and design		

A. OVERVIEW

Station Reinvestment Projects (individually, the "Project") involves complete refurbishment of critical station assets at a single transmission station. Each Project includes a consolidated replacement of multiple station assets that are at the end of their life and whose condition has been rated as high risk or very high risk in accordance with the asset condition assessment. The scope of the Project is primarily on the key station assets, such as transformers, breakers, switchgear and protection and control systems. It may also include other station assets, such as instrument transformers, disconnect switches and other ancillary equipment, where needed. The Project covers bulk transmission stations and load supply transmission stations.

As described in Transmission System Plan ("TSP") Section 2.1, prior to 2014, Hydro One's approach to station asset management was asset-specific. Separate programs were used to consider, plan for and implement replacements for particular asset types (i.e. transformers, breakers and switches) across the province. In 2014, Hydro One transitioned to an integrated approach to station asset management where possible. This change was largely driven by outage analysis and the recognition, based on asset demographics, that a large volume of renewal work would need to be performed in the coming years. Rather than making numerous return visits to the same stations to repair or replace different types of assets, requiring multiple outages, the integrated approach enables work that is required at a particular station to be bundled together and executed at once. Integration of station work and the timing for this work is oriented around key station assets (i.e. transformers, breakers, switches and protection and control equipment).

This station-focused approach addresses infrastructure that is aging and a high risk to system operation. Hydro One has established a recurring 7-10 year assessment cycle that enables all necessary renewal work to be performed at each of the 293 transmission stations during the cycle. By developing and implementing work packages for each station, this approach enables Hydro One to efficiently use outages and to minimize the total number of outages required to complete necessary renewal work. The candidate investments identified through the Asset Management process include station-specific packages of work that have been developed in accordance with the established assessment cycle.

Using the integrated approach, Hydro One plans to refurbish 21 transmission stations over the test period. Hydro One has evaluated various alternatives for the Project, as described below, and concluded that replacing multiple assets using an integrated approach at a single transmission station is the most cost effective and efficient undertaking. The projected sum of costs for the Projects is estimated to be $352.9 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need:

The Projects focus on the replacement of multiple station assets that facilitate power flows across the bulk electric system and transform power from a high transmission voltage to a lower transmission voltage. A Project is undertaken when multiple assets within the station may compromise the reliability of supply and result in higher failure rates due to their operation in deteriorated condition and beyond their expected service lives. Failures at a bulk station could constrain generation and interrupt supply to load centres. Failures at a load station typically result in outages for local distribution companies, constraining embedded generation resources and leaving customers without power, sometimes for prolonged periods of time.

The Projects address replacement needs identified during the asset assessment process. As discussed in TSP Section 2.1.2, Hydro One has a comprehensive asset management process that involves the ongoing monitoring and assessment of transmission asset needs. The assessment is based on risks identified from asset demographics, condition, environmental factors, utilization, costs comparison between refurbishment and replacement, and other lifecycle considerations. The goal of each asset assessment is to ensure that assets are not in deteriorated condition and to minimize any safety, reliability and/or environmental risks. All assets at a given station are assessed at the same time. Focus is given to transformers, breakers, and protection and control systems – as these are the most critical assets in the system and, in the event of their failure, can result in a direct outage to customer supply, compromise the integrity of the bulk system and/or constrain generation from key generation facilities in the Niagara, Bruce, and Pickering areas.

Upon identification of all the assets requiring replacement within the station, a decision is made whether an integrated approach or a specific asset replacement is preferred. If the assessment identifies multiple key station assets (i.e. transformers, breakers, and protection and control equipment) the condition of which warrants a replacement now or within the next three years, Hydro One then pursues an integrated approach. This approach focuses on a particular station where multiple key station assets require replacement, as driven by their condition, and may be accompanied by some level of electrical re-configuration to address operating concerns and customer preferences or to standardize the installed equipment. In the case where there are relatively few assets identified for replacement (e.g., one of the key station asset and accompanying ancillary equipment or a small subset of other minor station assets), then this station is identified as a candidate for a particular asset-focused replacement project (e.g. transformer replacement project or breaker replacement project). Ultimately all stations are assessed using the same asset risk assessment process. Depending on the final outcome of the assessment, (i.e. what assets are in high risk and in need of replacement) it dictates what grouping the project would fall into.

The next step is to consider if electrical reconfiguration of the station will result in any operational efficiencies through a reduction of major assets identified for replacement. These assets may include transformers, circuit breakers and the associated connection elements such as disconnect switches and main bus elements. For example, the existing configuration at Gage TS has been reviewed in light of changes in the load profile and as such, four end-of-life transformers will be replaced with two units. The new configuration will be a standard two transformer configuration resulting in operational efficiencies due to the application of standard procedures and a reduced complement of assets for maintenance. A similar reconfiguration is also being planned at Elgin TS and other stations, resulting in a total reduction of 17 power transformers over the planning period.

Assets requiring replacement due to condition-based assessments are then further evaluated based on the forecasted load growth in the area. If load is projected to increase, then the bundling of assets identified for replacement may be prudent to minimize future outage risk. Execution of the investment is likely to be accelerated to minimize the risk of unexpected failure at the forecasted loading. If load is projected to decrease, the bundled investment may result in reconfiguration that involves equipment decommissioning.

Hydro One actively works with the customers to capture their needs and preferences and implement the necessary changes to Hydro One designs, where feasible, to meet those needs. In cases where the need for asset replacement or upgrades is established due to customer requests, a bundled investment strategy would be recommended if it is likely to lower the costs to the customer and the rate pool. The relevant customer is consulted with respect to the pacing of the bundled investment so as to minimize any outages and direct costs to customers while maintaining the reliability of supply.

These factors are considered in conjunction every alternative listed below to determine the preferred alternative. The final decision to bundle asset replacements into a single integrated investment is established on a case-by-case basis. Details such as the in-service date and timing of the bundled investment are determined to minimize costs and maintain reliability of supply.

The above discussion describes the process Hydro One undertakes to determine whether to pursue an integrated approach to bundle the replacement of multiple key assets at a particular bulk station or load supply station. For each major station asset category, the specific asset-related drivers and needs for replacing particular key station assets are described in the following investment summary documents:

- For transformer replacement need and drivers, refer to SR-3 and SR-5;
- For switchgear need and drivers, refer to SR-4 and SR-6; and
- For protection and automation system need and drivers, refer to SR-7.

Investment Description

The Projects address the consolidated replacement of several assets that are end-of-life and are in deteriorated condition at a single transmission station. The Projects target stations with a significant population of station equipment that are identified as candidates for replacement and possible reconfiguration as a result of identified asset replacement needs.

As described in more details in TSP Section 2.1.2, Hydro One performs an asset risk assessment and, if as a result of this assessment, Hydro One identifies a significant number of major assets for replacement, then this station is subsequently identified as a candidate for a complete station refurbishment. Through the Investment Planning process described in TSP Section 2.1, all candidate investments undergo the risk based prioritization to determine whether they are included in the Investment Plan. The Projects target 21 bulk stations and load supply stations. Hydro One will replace 41 transformers, 286 breakers, and 780 protection systems. Hydro One will also address other minor station assets (e.g. ancillary equipment) where condition warrants replacement as well as any potential site and property issues, customer issues, safety and/or environmental concerns. A more detailed list of assets planned for replacement is presented in Appendix "A".

The Projects include functional reconfiguration to ensure alignment with applicable industry and regulatory standards. Functional reconfiguration is the reconnection of power system elements (e.g. breakers, transformers) within a transmission station into a new electrical configuration. This can either better facilitate a customer connection, a connection to the bulk power system or help eliminate operational restrictions or limitations which can aid in the transfer or restoration of power during a faulted condition where an element is removed from service. Functional configuration, where possible, allows Hydro One to replace two smaller rated transformers with a single standardized transformer that delivers the same capacity. This helps Hydro One maintain a standardized catalogue of power equipment to minimize the various types of spare equipment required. As a part of this investment, Hydro One will remove 17 transformers and 49 breakers from service through functional reconfiguration over the planning period.

Outcome

As a result of this investment, Hydro One will eliminate operational concerns through reconfiguration; reduce operational risks associated with the operation of end of life equipment; ensure compliance with Ministry of Environment, Conservation and Parks ("MOECP"), North American Electric Reliability Corporation ("NERC") and Northeast

Power Coordinating Council ("NPCC") requirements; maintain long-term bulk system reliability; maintain long-term reliability of the load supply stations; reduce constraints on generation resources.

The following table presents anticipated benefits in accordance with the Ontario Energy Board's ("OEB") Renewed Regulatory Framework ("RRF"):

Outcome Summary:

Customer Focus	• Maintain reliability performance of bulk electricity system through the replacement of end of life equipment that is in poor condition • Maintain reliable power delivery at load supply stations.
Operational Effectiveness	• Improve the operational effectiveness of bulk and load supply stations through reconfiguration and standardization of new equipment and design
Public Policy Responsiveness	• Ensure compliance with applicable regulatory and environmental requirements
Financial Performance	• Realize cost savings by addressing multiple deteriorated assets within a station as part of the same project.

C. EXPENDITURE PLAN

As discussed above, this investment is needed to replace various bulk power and load supply station assets that have reached their expected service life ("ESL") and are in deteriorated condition, which may lead to unexpected failures. Hydro One planned this investment to achieve completion as effectively and efficiently as possible.

Table 1 summarizes historical and projected spending on the aggregate project level. Since this investment consists of a multiple Projects, as presented in Appendix "A", Table 1 below consolidates all the costs for individual projects and presents the total investment cost. The "Previous Years" costs are the direct costs for Projects incurred prior to 2020. Likewise, the costs noted in "Forecast 2025+" are project costs forecasted beyond 2024.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	296.4	113.5	129.9	125.2	90.6	55.6	14.7	825.9
Less Removals	8.7	6.4	4.5	4.6	2.7	1.7	0.4	28.9
Gross Investment Cost	**287.8**	**107.0**	**125.4**	**120.6**	**87.9**	**53.9**	**14.3**	**796.9**
Less Capital Contributions	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.6
Net Investment Cost	**287.4**	**106.9**	**125.4**	**120.6**	**87.9**	**53.9**	**14.3**	**796.4**

[1] *Includes overhead at current rates.*

Table 2 below presents projected costs on an individual project basis. It also provides total costs for each individual project along with the proposed in-service date.

Table 2 - Detailed Project Costs

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
Elgin TS	10.4	0.0	0.0	0.0	0.0	10.4	68.9	2020
Sheppard TS	5.0	0.0	0.0	0.0	0.0	5.0	40.9	2020
Pine Portage SS	6.2	(0.1)	0.0	0.0	0.0	6.1	17.9	2020
Hanmer TS	7.9	0.0	0.0	0.0	0.0	7.9	77.4	2020
Gage TS	16.0	13.0	2.3	0.0	0.0	31.3	50.4	2021
Kenilworth TS	10.2	6.1	0.0	0.0	0.0	16.3	31.1	2021
Runnymede TS	10.3	2.6	0.0	0.0	0.0	12.9	25.5	2021
Belleville TS	7.1	2.9	0.0	0.0	0.0	10.0	11.1	2021
Martindale TS	10.1	7.5	0.0	0.0	0.0	17.7	71.8	2021
Carlton TS	1.0	4.2	6.5	7.3	0.0	19.0	20.8	2022
Port Colborne TS	6.2	16.4	7.4	0.0	0.0	30.0	31.6	2022
Slater TS	1.2	7.9	3.1	0.0	0.0	12.2	12.9	2022
Wonderland TS	1.4	9.9	11.9	3.3	0.0	26.5	27.0	2023
Lambton TS	0.8	4.7	20.1	7.7	0.0	33.3	33.4	2023
Glendale TS	5.3	17.6	16.8	4.2	0.0	43.9	45.6	2023
Fairbank TS	5.9	24.0	25.8	6.7	0.0	62.4	64.8	2023
Arnprior TS	1.1	6.6	15.5	5.4	0.0	28.6	29.3	2023
Hanover TS	0.4	0.6	4.2	18.3	7.0	30.6	30.6	2024
Kent TS	0.1	0.6	2.7	19.1	16.0	38.6	42.2	2025
St. Andrews TS	0.0	0.2	0.8	4.8	20.6	26.4	34.4	2025
Wawa TS	0.2	0.8	3.4	11.0	10.3	25.7	28.7	2025
Net Investment Cost	**106.9**	**125.4**	**120.6**	**87.9**	**53.9**	**494.7**	**796.4**	

Furthermore, the following factors also affect the capital expenditures required for this investment:

- The number of transformers, breakers, protection systems, and ancillary equipment being replaced
    - Higher voltage transformers and breakers and ancillary equipment are more costly from a material perspective as is the overall installed cost due to required clearances for high voltage equipment.
- Applicability of MOECP, NERC and/or NPCC requirements

  - Where stations are subject to NERC/NPCC requirements or environmental work (i.e. spill containment and/or oil water separators are required) increased costs may be incurred to facilitate the work required to meet the requirements.
- The complexity of project staging and outages required to facilitate work
  - The more complex the project, the more inter-connections, and the more outages required will increase the cost of the project.
- Whether the Project is a Greenfield replacement or *in-situ* replacement requiring complex contingency planning
  - Generally, if space permits, either within the existing station fence or nearby, a Greenfield solution may be less costly as it can be constructed with minimal interference to daily operations.
  - *In situ* replacement is generally more difficult, from both engineering design and construction perspectives as other equipment will need to be removed from service to facilitate construction and ensure safety and appropriate clearances. This increases the time required for construction and can impact customers as they will be supplied from only a single supply during these times.
- The location of the station, whether in an isolated rural area or congested urban area
  - Generally working in a congested urban station will increase costs and lengthen the overall construction time of the project with respect to clearances in order to work safely.

D. ALTERNATIVES

Hydro One considered the following alternatives before arriving at this investment decision.

Alternative 1: Reactive Component Replacement involves waiting for deteriorated condition transformers, breakers, or ancillary equipment to fail and replace components on a reactive basis. This alternative is more costly not only for Hydro One but also for impacted customers. Hydro One has rejected this alternative for the following reasons.

- Assets in deteriorated condition will continue to deteriorate and decline, thereby increasing the likelihood of unexpected failures. These failures might be prolonged and might result in extended equipment and customer outages which will subsequently lower the System Average Interruption Duration Index ("SAIDI") and Transmission System Average Interruption Frequency Index ("SAIFI") performance.
- An increased likelihood of unexpected failures would lead to increased environmental risk due to the possibility of a release into the environment during a failure event.
- An increased likelihood of unexpected failures would lead to increased safety risk due to the possibility of a failure event being catastrophic in nature.
- Since these replacements would likely be executed on an emergency basis, it would result in constant reprioritization of planned work and inefficient redeployment of resources.
- This alternative limits the ability to account for future requirements and has a high risk of re-work and future additional costs.
- This strategy is likely to increase operating and maintenance costs, decrease equipment performance and may impact the safety of personnel on site.

Alternative 2: Planned Replacement of Components (Unbundled) involves replacing individual station components in high risk and deteriorated condition on a sequential basis as each component reaches its end of useful service life. This alternative is viable only when single components at a transmission station are deteriorated. Unlike reactive replacements, planned replacements have the advantage of minimizing system and equipment outages through coordinated outage plans. However, this alternative is not efficient when multiple components at a transmission station are in deteriorated condition or operational concerns exist with respect to these components. Since a component-based planned replacement strategy would only replace assets as they come to end of life, Hydro One would not realize any efficiency during execution of the design, construction, and commissioning stages of the work that a station-centric, bundled replacement strategy offers. Furthermore, this alternative does not offer any opportunities to reconfigure the physical or electrical layout of the station in order to minimize future maintenance requirements or to eliminate any existing operational concerns.

Alternative 3: Station Refurbishment – Bundled Replacement of Components is the preferred investment option. It addresses the needs identified at the transmission station to maintain reliability for Hydro One's bulk transmission system in the most cost effective and efficient manner. Hydro One can refurbish entire stations that have a significant population of assets in high risk condition, before failures occur. Furthermore, for transmission stations that have a significant population of deteriorated, high risk condition assets and where operational concerns could be mitigated or eliminated through reconfiguration, station refurbishment is the best alternative as it enables a holistic assessment of asset and operational needs which are consolidated into a single integrated investment. Bundling the replacement of transmission station components also reduces the number and duration of planned outages affecting customers connected to the station. For example, if a circuit breaker disconnect switch is replaced together with the circuit breaker outages efficiencies are realized since the grouped equipment that requires an outage is similar for the switch as it is for the breaker. Had the replacements been sequential the outages for the replacements would have to be duplicated, as would the resource requirements to complete the work.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of bulk station transformer replacement projects are: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges, or regulatory approvals. A thorough risk assessment workshop is performed during the initial project planning phase where all known risks are identified and a mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan that aims to eliminate or minimize the loss of supply to the customer. The plan might include the construction of a temporary by-passing circuit or supply of portable generation that will maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. As another example, to allow for early identification of real estate issues, Hydro One involves real estate from project inception. The aim is to identify issues such as missing or inadequate land rights, so that Hydro One can try to resolve them prior to execution of the project.

APPENDIX A – DETAILED TOTAL PROJECT PLAN

Station Name	Scope and Impacts	Transformers		Breakers		Prot.	In Service Year
		Repl.	Rem.	Repl.	Rem.		
Elgin TS	This investment will result in the complete rebuild and reconfiguration of Elgin TS with new equipment built to current standards. The station refurbishment will address four (4) high risk rated power transformers with the installation of two (2) new transformers, forty-six (46) low risk low voltage breakers with the installation of new Medium Voltage Gas Insulated switchgear (MVGIS) and non-standard spill containment with the installation of current MOECP compliant spill containment facilities. The reduction in assets as a result of reconfiguration along with installation of current Hydro One standard equipment will reduce near term maintenance commitments. Customer consultations have taken place with Alectra Utilities and coordination of distribution supply egress modification is planned to facilitate minimal customer impact.	2	2	46	0	90	2020
Sheppard TS	This investment involves the complete rebuild of the existing Sheppard TS T3/T4 switchyard which includes two power transformers, 27.6kV switchyard, protection and control equipment, and supporting infrastructure in a greenfield location beside the existing T3/T4 switchyard. The T3 and T4 transformers, both constructed in 1962, show signs of insulation degradation, as determined through dissolved gas analysis; have significant oil leaks; and contain high levels of polychlorinated biphenyls (PCBs) within the high voltage bushings. As well, the existing T3/T4 switchyard structure contains “back-to-back” switching resulting in clearance concerns. Many of the associated protection and control systems are either obsolete or in poor condition. Not proceeding with this investment will lead to increased risk of declining long-term supply reliability to Toronto Hydro in the Toronto Area.	2	0	12	0	36	2020
Pine Portage SS	The investment will result in the rebuild of the Pine Portage SS station including 115kV oil circuit breakers, 115kV disconnect switches, protection and control systems, and other associated auxiliary components that are at end of life due to poor condition, obsolescence, declining performance and high maintenance costs. The protection and control systems and associated auxiliary systems will be relocated to the switchyard of the station as they are currently located in OPG facilities as part of the demerger process. Implications of not completing this work include significant risk of further equipment deterioration and declining reliability to the customers in the Thunder Bay area, as well as a negative impact on transmission capacity, reliability and operability of the station.	0	0	5	0	15	2020

Station Name	Scope and Impacts	Transformers		Breakers		Prot.	In Service Year
		Repl.	Rem.	Repl.	Rem.		
Hanmer TS	This investment involves replacement of 500kV reactors and associated spill containment systems, 230kV circuit breakers; 500kV free standing current transformers, 500kV & 230kV disconnect switches, protection and control systems, and other associated auxiliary components in order to maintain the reliability of supply to the customers in the Sudbury area. It will decrease the risk of further equipment deterioration and maintain transmission reliability between Northern and Southern Ontario.	0	0	11	0	35	2020
Gage TS	This investment will result in a complete rebuild of the station and replacement of end of life equipment including 115kV to 13.8kV transformers and low voltage circuit breakers in a new configuration. The new equipment will maintain the reliability of supply to Alectra Utilities and to embedded customers such as Arcelor Mittal Dofasco, US Steel, Max Aicher North America and several other retail customers by reducing the risk of equipment failure.	2	2	10	1	65	2021
Kenilworth TS	Assets including power transformers and low voltage breakers in addition to associated protection and control facilities are in degraded condition as verified through visual inspection and diagnostic testing. Oil analysis of the power transformers show advanced signs of insulation degradation, indicating a high probability of failure in the near future. The station refurbishment will replace a power transformer, low voltage metalclad facilities comprised of a number of breakers with current Hydro One standard metalclad equipment along with associated PCT facilities in addition to installation of current MOECP compliant spill containment facilities and drainage requirements. The reduction in assets along with installation of current Hydro One standard equipment will reduce near term maintenance commitments along with improving personnel safety by deploying current Hydro One standard equipment that eliminates the present need for additional safety measures to be taken when performing maintenance activities on the low voltage switchgear identified for replacement. In addition, replacing these assets will maintain reliability of supply to Alectra Utilities and embedded major industrial customer ArcelorMittal Dofasco.	1	2	16	11	48	2021

Station Name	Scope and Impacts	Transformers		Breakers		Prot.	In Service Year
		Repl.	Rem.	Repl.	Rem.		
Runnymede TS	The majority of assets in the Runnymede T3/T4 switchyard, including two power transformers and the 27.6kV switchyard, are at end of life due to deteriorating condition. The T3 and T4 power transformers show signs of insulation degradation as determined through dissolved gas analysis; show evidence of oil leaks within the acoustic housing; and each have a subset of bushings with high levels of polychlorinated biphenyls (PCBs). The existing 27.6kV switchyard is a legacy structure that requires expanded outage zones to complete maintenance activities. Rebuilding the Runnymede T3/T4 switchyard will renew asset conditions and continue to ensure long term supply reliability and performance to Toronto Hydro customers.	2	0	13	0	0	2021
Belleville TS	The transformer T2 is at end of life and degraded condition. The station work will include replacing T2 and existing station service transformers and associated protection and control equipment.. Replacement will maintain reliability of supply to Veridian Utility customers and decrease the risk of equipment failure.	1	0	1	0	1	2021
Martindale TS	This investment will address end of life asset replacements in the 230kV and 115kV including 230kV to 115kV transformers, 230kV circuit breakers, 115kV and 230kV disconnect switches, protection and control systems, and other associated auxiliary components. Implications of not completing this work include a significant risk of further equipment deterioration and declining transmission system reliability in the Sudbury Area.	2	0	7	0	88	2021
Carlton TS	The existing metalclad switchgear, low voltage oil circuit breakers supplying non-industrial customer load along with all site PCT facilities are in a degraded condition as verified through visual inspection and diagnostic testing. In addition, due to reduced customer loading, it has been deemed prudent at this time to reconfigure the station by removing power transformers and associated switchyard comprised of a number of low voltage breakers from service. The reduction in assets along with installation of current Hydro One standard equipment will reduce near term maintenance commitments. Customer consultations have taken place with Alectra Utilities and coordination of distribution supply egress modification is planned to facilitate minimal customer impact.	0	2	19	8	68	2022
Port Colborne TS	This investment will result in replacement of transformers T61/T62, low voltage switchyard and associated P&C devices. Spill containment facilities will also be addressed through this investment. The assets are at the end of their useful life and replacing them will maintain reliability of supply to Canadian Niagara Power Inc.	2	0	8	0	18	2022

Station Name	Scope and Impacts	Transformers		Breakers		Prot.	In Service Year
		Repl.	Rem.	Repl.	Rem.		
Slater TS	The transformers at Slater TS are at end of life and degraded condition (i.e. leaking oil). The station work will consist of Replacing , T2, and T3, the AC station service system and reconfigure the station DC supply, remove auto ground switch and upgrade associated protection and control equipment. Replacement will maintain reliability of supply to downstream customers and decrease risk of equipment failure.	2	0	0	0	0	2022
Wonderland TS	This investment will address end of life asset replacements including one 230kV to 27.6kV transformer, low voltage circuit breakers, associated protection and control systems, and other associated auxiliary components. The new equipment will maintain the reliability of supply to London Hydro and Hydro One distribution customers by reducing the risk of equipment and delivery point failure.	1	0	13	0	26	2023
Lambton TS	This investment will address end of life asset replacements including 230kV to 27.6kV transformers, 27.6kV circuit breakers, associated disconnect switches, protection and control systems, and other associated auxiliary components in order to maintain the reliability of supply to customers. This investment will be coordinated with OPG to maintain the reliability of supply in the area.	2	0	9	0	24	2023
Glendale TS	This investment will address end of life assets resulting in replacement of transformer T1, reconfiguration and replacement of all low voltage switching facilities along with all site P&C.	1	2	18	3	75	2023
Fairbank TS	The majority of assets at Fairbank TS including four power transformers and both 27.6kV switchyards are at the end of life due to deteriorated condition and obsolescence. Refurbishing the Fairbank TS switchyards will ensure long term supply reliability and performance to Toronto Hydro Customers. This station is rated as one of the worst stations for delivery point interruptions.	4	0	24	0	44	2023
Arnprior TS	A station assessment has identified that station equipment including transformers and associated protection and control equipment are at end of life and are in degraded condition. The station refurbishment work will replace T1/T2, have new PCT building, replace MV switchyard, and reconfigure the AC station service. Replacing these assets will maintain reliability of supply to Hydro Ottawa and decrease the risk of equipment failure.	2	0	5	0	25	2023
Hanover TS	This investment will address end of life asset replacements which includes one 115kV to 44kV transformer, low voltage circuit breakers, associated protection and control systems, and other associated auxiliary components. Replacement of this equipment will result in a reduced risk of equipment failure thereby maintaining the reliability of supply to embedded customers such as Westario Power, Wellington North Power and other distribution retail customers.	1	0	10	0	38	2024

Station Name	Scope and Impacts	Transformers		Breakers		Prot.	In Service Year
		Repl.	Rem.	Repl.	Rem.		
Kent TS	This investment will result the replacement of end of life equipment including two 230kV to 27.6kV transformers and seventeen low voltage circuit breakers, associated protection and control and ancillary equipment. The new equipment will maintain the reliability of supply to Entegrus Powerlines Inc. and several embedded retail customers by reducing the risk of equipment and delivery point failure.	2	0	15	2	26	2025
St. Andrews TS	This investment will address end of life asset replacements including two 115kV to 27.6kV transformer, low voltage circuit breakers, associated protection and control systems, and other associated auxiliary components. The new equipment will maintain the reliability of supply to Blue Water Power and embedded customers (Imperial Oil) by reducing the risk of equipment and delivery point failure.	2	0	13	0	35	2025
Wawa TS	This investment will address end of life asset replacements in the 230kV and 115kV switchyards which are negatively impacting transmission system reliability due to their poor condition and poor performance. End of life assets include 230kV to 115kV transformers, 230kV circuit breakers, 115kV circuit breakers, 115kV and 230kV disconnect switches, protection and control systems, and other associated auxiliary components.	2	0	7	0	23	2025

SR-03 Bulk Station Transformer Replacement Projects

Start Date:	Q1 2016	**Priority:**	Medium
In-Service Date:	Q4 2027	**3 Year Test Period Cost ($M):**	157.5
Trigger(s):	Strategic, System Renewal		
Outcomes:	Ensure compliance, system reliability, customer satisfaction, operational efficiencies and reduce maintenance costs		

A. OVERVIEW

Bulk Station Transformer Replacement Projects (the "Project") are primarily a series of individual transformer replacement projects that involves the replacement of bulk station power transformers (autotransformers, phase shifters, regulators) that are at or beyond the end of their life. The Project might also involve the replacement of other equipment such as select breakers, protection and control systems and other ancillary equipment, where needed. Prior to replacement, Hydro One will perform an asset risk assessment to ensure that these additional assets are also at the end of their life and that their condition or other factors warrant the replacement.

The bulk transmission system is the "backbone" of the Ontario electricity system. Large bulk transformers are critical at ensuring the reliable performance of the bulk electricity system. These transformers facilitate the transfer of large power flows between the 500kV, 230kV, and 115kV systems and between interties with other jurisdictions. As a licensed transmitter operating transmission facilities greater than 100 kV, Hydro One is obligated to comply with the planning, operating and reliability criteria and standards mandated by NERC and NPCC. Furthermore, Hydro One transmission customers include large electricity generators, large industrial end-users and the majority of Ontario's LDCs. In light of the foregoing, it is apparent that there is a heightened need to ensure that these critical assets of the bulk electricity system are in good condition for safe, secure and reliable operation.

The Project pacing has been influenced by bulk transformer fleet demographics, observed condition, anticipated condition, and performance factors as well as environmental and safety concerns, as described below. Based on Hydro One's overall transformer demographic profile, it is forecasted that an increasing number of units will age beyond expected service life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Project.

Hydro One has evaluated various alternatives for the Project, as described below, and concluded that replacing deteriorated bulk station transformers is the most cost effective and efficient undertaking. The projected costs of the Project are estimated to be $157.5 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

As discussed in TSP Section 2.2.1, Hydro One has a thorough and ongoing asset management process that involves monitoring and reviewing transmission assets and assessing their condition. Hydro One's transformer asset strategy is to proactively inspect and monitor the transformer fleet. This allows Hydro One to manage maintenance needs and assess the transformer's condition as a factor to determine the need for asset refurbishment or replacement. Assessments to repair or replace transformers are done on an individual basis. The assessment is based on risks identified from demographics, condition, environmental factors, utilization, costs comparison between refurbishment and replacement, and other lifecycle considerations. Units that are considered high risk, or with known manufacturer defects/obsolesce, or with anticipated higher repair costs are prioritized for replacement.

Hydro One's transmission system includes 293 stations. Hydro One has established a recurring 7-10 year assessment cycle that enables all necessary renewal work to be performed at each of the 293 transmission stations during the cycle. The goal of each asset assessment is to ensure that the assets are not deteriorated, there are no risks that may compromise the reliability of the system, and they do not pose any safety and/or environmental risk. All assets at a given station are assessed at the same time with a particular focus to transformers, breakers, and protection & control systems – as these are the most critical assets in the system and have a direct impact on a customer. If the assessment identifies multiple station assets (i.e. transformers, breakers and protection and control equipment) whose condition warrants a replacement, Hydro One then pursues an integrated approach. The asset replacements are bundled into an integrated station-centric investment project with the main components being identified as the driver for the project. This integrated approach is further described in SR-02. In the case where only transformers are identified as the main asset for replacement along with a small subset of other minor station assets, the station is identified as a candidate for a transformer-focused replacement project.

As of December 2018, Hydro One has 140 bulk station transformers in service. Currently, 24.7% of the Hydro One bulk station transformer population is beyond ESL. Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions. The average age of the bulk station transformer fleet is 32 years. Assuming no replacements, Hydro One anticipates that 39% of the bulk station transformer population will exceed their ESL by 2024, and 46% of the population will exceed their ESL by 2029.

Transformer condition is a leading predictive indicator of equipment reliability and usually the main driver for replacement. Condition is determined by industry standard diagnostic testing which includes routine transformer oil testing and other maintenance examinations. Transformer insulation generally degrades as a function of time and other operational factors (i.e. loading levels) and this degradation is irreversible, ultimately requiring asset replacement. Furthermore, transformer ESL has a direct correlation to anticipated insulation condition. Within the industry, there is a correlation between the highly flammable and volatile chemical compound - furan and the degree of polymerization of insulation paper. The degree of polymerization of the paper is an indicator of insulation strength and condition. Furan is a chemical that can be detected via oil samples. Furan is a by-product of paper degradation as it ages and decomposes. Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. Assessment of the bulk station transformer fleet's condition based on oil analysis results shows that approximately 14% are rated high or very high risk, as illustrated in Figure 1.

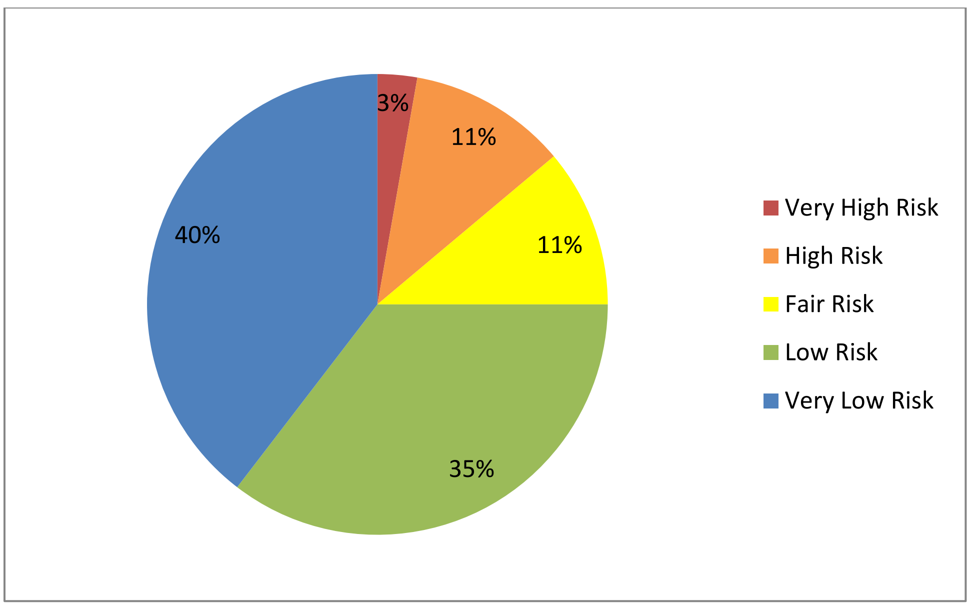

Figure 1 - Condition Summary of Bulk Station Transformer Fleet

Transformer equipment performance is measured by assessing the duration and frequency of forced outages related to the transformer. A "forced outage" is the automatic or forced manual removal of a transformer caused directly by it or its auxiliary equipment. Transformer forced outages have been a major cause of equipment unavailability over the past 10 years, representing 13% of these equipment-caused events. Over the last 10 years, Hydro One has experienced an average of 4 Class 1 failure annually. Class 1 failures are unpredictable and irreparable, and can lead to catastrophic consequences. Table 1 below summarizes the number of Class 1 failures by voltage class.

Table 1 - Transformer Annual Class 1 Failure Rates over the Past 10 Years (2008-2017) in Percentage of Transformer Population

Year	115kV	230kV	500kV	5 Year Average Annual Failure Rate, All Voltage classes
2008-2012	0.40%	0.37%	1.41%	0.44%
2013-2017	0.56%	0.41%	2.44%	0.59%
10 Year Average Annual Failure Rate	0.48%	0.39%	1.92%	0.51%

Regarding oil leaks, approximately 36% of the bulk transformer fleet has confirmed oil leaks via visual inspections, with 8.5% classified as major leakers. Based on Hydro One's experience, new leaks will appear in approximately 1% of the fleet's population per year, most commonly as a result of gasket deterioration over time. Transformer leaks not only create environmental concerns, but also generate reliability issues, as in-service transformers may be forced out due to low oil levels. Active leaks also provide a path of moisture ingress into the transformer's internal winding. Finally, severe oil leaks and frequent oil top ups also compromise the accuracy of condition assessments because they dilute the oil and may result in a false improved oil test result.

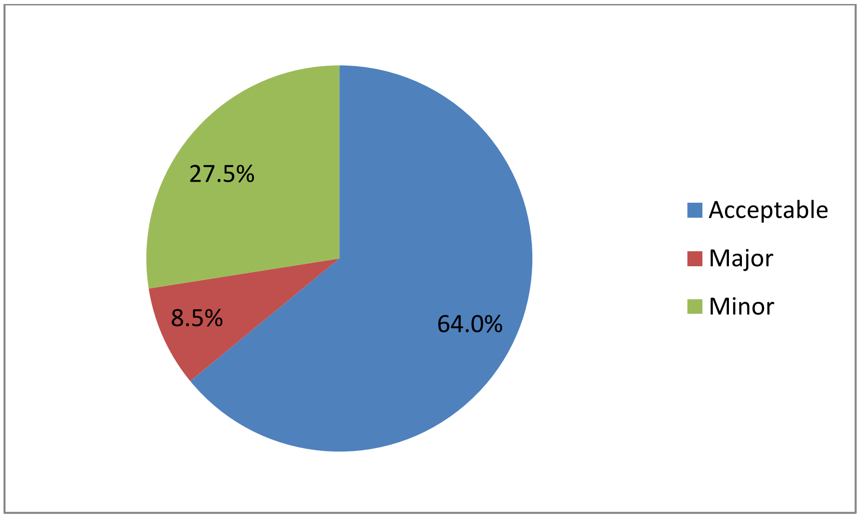

Figure 2 – Bulk Station Transformer Leak Assessment

Furthermore, the PCB Regulations, which came into effect in 2008, and for which amendments came into force on January 1, 2015, implemented deadlines on equipment already in use and in storage, in order to accelerate the elimination of PCBs from the Canadian environment. The PCB Regulations require all oil-filled equipment to contain PCB levels of less than 50 parts per million (ppm) by December 31, 2025. The PCB Regulations impact transformer oil filled bushings. From a fleet wide perspective, as of December 2018, up to 43% of Hydro One's transformer oil-filled bushings may require work related to PCB testing verification or replacements. When high PCB levels are present in a transformer approaching end of life, it may be more economical to slightly advance replacement than to make repairs to resolve high PCB levels on a unit near end of life.

With regards to failure risk, bulk transformer failure could partially or entirely constrain generation resources and would lessen the reliability of bulk power flows to load centres. For select transmission interties between Ontario and other jurisdictions that utilize phase shifters and regulating transformers, failures would result in decreased available import/export capacity. As well, reduced bulk transformation capacity could result in bottlenecks that affect the wholesale power market and power flows between regions. If left unattended, the Hydro One bulk station transformer fleet will continue to degrade and the fleet demographic with transformers that are in a high or very high risk state will continue to increase, thereby resulting in more frequent and unexpected failures.

Investment Description

The Project is classified primarily as a transformer replacement project. The Project involves a series of individual projects that target a like-for-like replacement of deteriorated bulk power transformers at several bulk transformer stations. The Project also addresses replacements of select breakers, protection and control systems, switches, batteries, chargers, instrument transformers and may additionally address site or property issues, customer issues, safety concerns, environmental compliance, and operational issues.

Hydro One's plan for the transformer fleet replacement over the next five years has been influenced by fleet demographics, observed condition, anticipated condition, and performance factors as well as environmental and safety concerns, as described above. Cumulatively, the Project targets the replacement of 33 transformers, 52 breakers, and 216 protection systems at 12 stations, as further detailed in Appendix "A" below.

Outcome

As a result of the Project, Hydro One will reduce operational risks (e.g. bottled generation, reduced transfer capability, restricted power flows) associated with the operation of end-of-life equipment; ensure compliance with government and industry regulations; maintain long-term bulk power flow reliability throughout the power system; maintain long-term reliability of import/export capacity on select transmission interties; and mitigate the risk of constraining generation resources.

The following table presents anticipated benefits as a result of the Project in accordance with the OEB's RRF:

Outcome Summary:

Customer Focus	• Maintain reliability performance of bulk electricity system power flows through the replacement of end-of-life units.
Operational Effectiveness	• Maintain operational flexibility of the bulk electricity system through the replacement of end-of-life units.
Public Policy Responsiveness	• Comply with applicable regulatory and environmental requirements
Financial Performance	• Realize cost savings by addressing multiple deteriorated assets within the station as part of the same project.

C. EXPENDITURE PLAN

As discussed above, the Project is needed to replace bulk power transformers as well as other bulk station assets that may compromise the reliability of supply due to the assets being deteriorated and at end of life, which may lead to unexpected failures. Hydro One has planned the Project in a way that strives to complete it as effectively and efficiently as possible so as to minimize the cost.

Table 2 summarizes historical and projected spending on the aggregate project level. Since the Project consists of multiple projects, as presented in Appendix "A", Table 2 below consolidates all the costs for individual projects and presents the total Project costs. The "Previous Years" costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 Test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024.

Table 2 - Total Investment Cost

($ Millions)	**Prev. Years**	**2020**	**2021**	**2022**	**2023**	**2024**	**Forecast 2025+**	**Total**
Capital[1] and Minor Fixed Assets	13.4	34.5	53.8	75.4	140.7	131.7	65.8	515.3
Less Removals	0.6	1.3	1.8	2.3	4.2	4.0	2.0	16.1
Gross Investment Cost	**12.8**	**33.2**	**52.0**	**73.1**	**136.5**	**127.8**	**63.8**	**499.2**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**12.8**	**33.2**	**52.0**	**73.1**	**136.5**	**127.8**	**63.8**	**499.2**

[1] *Includes overhead at current rates.*

Table 3 below presents projected costs on an individual project basis. It also provides a total costs for each individual project along with the proposed in-service date.

Table 3 - Detailed Total Project Costs

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
Detweiler TS	9.1	4.8	0.0	0.0	0.0	13.9	22.2	2021
Keith TS	12.2	11.4	8.7	8.7	0.0	41.0	42.6	2023
Seaforth TS	7.4	17.4	6.3	7.9	0.0	39.0	40.1	2023
Sarnia Scott TS	0.6	2.9	9.3	9.0	2.2	23.9	24.3	2024
Otto Holden TS	1.8	7.5	15.5	12.3	2.8	40.0	40.5	2024
Fort Frances TS	0.5	2.8	9.0	8.7	2.2	23.1	23.5	2024
Buchanan TS	0.4	0.6	3.2	10.6	10.1	24.9	27.5	2025
Middleport TS	0.0	0.4	0.8	5.3	16.4	22.9	29.0	2025
Manby TS	0.2	0.6	3.0	22.7	27.8	54.2	62.3	2025
Algoma TS	0.5	0.9	5.9	16.2	14.5	38.1	41.8	2025
Porcupine TS	0.5	1.2	9.3	25.0	21.8	57.9	63.3	2025
Beach TS	0.0	1.3	1.3	5.2	16.1	23.9	58.7	2027
Net Investment Cost	**33.2**	**52.0**	**73.1**	**136.5**	**127.8**	**422.5**	**499.2**	

Furthermore, the following factors also affect the capital expenditures required for the Project:

- Applicability of government and industry regulations:
    - When a transformer is replaced, there are requirements from the Ministry of the Environment, Conservation and Parks (MOECP) for spill containment and oil/water separators to mitigate the risk to the environment if oil is spilled.
    - As well, PCB compliance regulations established by Environment Canada drive the cost analysis of whether to retro-fill (refill) oil equipment or replace the PCB affected equipment. The OM&A cost to retro-fill the main tank on a power transformer is not deemed prudent for units approaching or beyond their ESL given the increased likelihood of failure. The preference is to proceed with a capital replacement due to the reduced rate impact, greater reliability and long-term benefits.

- Complexity of project staging and outages required to facilitate work:
    - Increases the cost of the planning portion of the project.
    - Increases overall duration of project (interest and overhead costs increases).

- Whether like-for-like replacements are installed in a new location or installed in-situ requires complex contingency planning:
    - New location will require additional facilities to be installed to connect the equipment rather than re-using existing facilities (i.e. bus work and supporting structures/foundations), increases cost.
    - Contingency planning can increase cost by requiring backup transformer installations, temporary supplies, etc.

- Site conditions and challenges:
    - Urban areas have many constraints such as outage planning, construction staging and contingency planning which could add to the project's duration and complexity and result in higher costs (e.g. working in space-constrained stations; work within neighborhoods where streets are congested and working hours may be constrained due to noise requirements; unique design and construction challenges; outage constraints as service still needs to be maintained amidst the required work).
    - Remote rural areas will increase costs due to difficulty of working on difficult terrain, difficulty accessing the station with heavy equipment, delivery of large equipment, etc.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: Reactive Component Replacement involves waiting for deteriorated condition transformers, breakers, or ancillary equipment to fail and replace components on a reactive basis. This alternative is more costly not only for Hydro One but also for impacted customers. Hydro One has rejected this alternative for the following reasons:

- Assets in deteriorated condition will continue to deteriorate and decline, thereby increasing the likelihood of unexpected failures. These failures might be prolonged and might result in extended equipment and customer outages which will subsequently lower SAIDI and SAIFI performance.
- An increased likelihood of unexpected failures would lead to increased environmental risk due to the possibility of a release into the environment during a failure event.
- An increased likelihood of unexpected failures would lead to increased safety risk due to the possibility of a failure event being catastrophic in nature.
- Since these replacements would likely be executed on an emergency basis, it would constantly result in the reprioritization of planned work and inefficient redeployment of resources.
- This alternative limits the ability to account for future requirements and has a high risk of re-work and future costs.
- This strategy is likely to increase OM&A costs, decrease equipment performance and might impact the safety of personnel on site.

Alternative 2: Station Refurbishment involves the refurbishment of the entire station where significant populations of assets are in a high risk condition, before failure occurs. This alternative is only a viable solution where other station assets, such as transformers and switching facilities, are in a deteriorated, high risk condition. This alternative has been considered for the Project and has been rejected as there is insufficient justification to proceed with a complete station refurbishment. Hydro One does not replace transmission assets unless asset condition or other factors warrant replacement. Where the majority of assets are EOL, this alternative may then be considered, but then the project would fall under the SR-02.

Alternative 3: Like-for-Like Planned Replacement is a preferred undertaking. It involves proactively replacing individual station components in a single integrated investment, with transformers being the primary project driver and additional station assets such as switchgear and ancillary equipment being included that have a deteriorated, high risk condition. This alternative is recommended as it addresses the needs identified at the station to maintain the reliability of Hydro One's transmission system in the most cost effective manner, consistent with the findings of the customer engagement process. This alternative focuses on the replacement of select equipment in a like-for-like manner, unless otherwise requested to meet broader system needs.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of bulk station transformer replacement projects are: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges, or regulatory approvals. A thorough risk assessment workshop is performed during the initial project planning phase where all known risks are identified and a mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize the risk of supply loss to the customer. The plan might include the installation of a temporary transformer or supply of portable generation that will maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. Another example is the involvement of real estate from the project inception. It allows for the early identification of real estate issues, such as missing or inadequate land rights. Once the issue is identified, Hydro One tries to resolve it prior to execution of the project.

1 **APPENDIX A – DETAILED TOTAL PROJECT PLAN**

Station Name	Scope and Impacts	Transformer Repl.	Breakers Repl.	Prot. Repl.	In Service Year
Detweiler TS	T2 and T4 are to be replaced as they have significant leaks and are at end of life. In 2011 and 2014 a total of 5870 litres of oil were required in emergency corrective top-ups for T2 amounting to over 3.5% of total oil volume. In 2011 and 2013 a total of 1900 litres of oil were required in emergency corrective top-ups for T4. This investment will maintain the reliability of supply to the Kitchener-Waterloo area.	2	0	11	2021
Keith TS	In addition to being at end of life and obsolete, T11 and T12 autotransformers do not have a self-cooled rating and represent a high risk of failure in case of loss of AC station service. The T11 and T12 units are to be replaced and upgraded from 125 MVA to 250 MVA in order to maintain the reliability of supply in the Windsor area and of the international tie-lie connection to the United States via Michigan. This project will also address the end of life step-down transformer, T1 that supplies Enwin Utilities.	3	1	17	2023
Seaforth TS	T1 and T2 DESN transformers are to be replaced to maintain reliability of supply to Erie Thames Power Lines, Festival Hydro, Dublin DS and embedded generation customers such as St.Columban 2 Wind farm, Brussels DS and Hurondale DS. The T5 and T6 autotransformer's off load tap changers are inoperable and obsolete. In order to maintain the reliability of supply and voltage regulation to customers and generators in the area, the IESO has recommended advancing the replacement of T5 and T6. This investment will maintain the reliability of supply in western Ontario between London, Kitchener-Waterloo and the Bruce generation complex.	4	2	25	2023

Station Name	Scope and Impacts	Transformer Repl.	Breakers Repl.	Prot. Repl.	In Service Year
Sarnia Scott TS	This investment will address end of life asset replacements in the 230kV and 115kV switchyards which are negatively impacting transmission system reliability due to their poor condition. End of life assets include one 230kV to 115kV transformer, five 115kV circuit breaker, 115kV and 230kV disconnect switches, protection and control systems, and other associated auxiliary components. This investment is expected to maintain the reliability of supply in the Windsor area.	1	5	23	2024
Otto Holden TS	This investment is driven by the need to replace a number of assets that are near end of life at Otto Holden TS. The main assets driving this investment are transformers T3, T4 (six single-phase units) and 115kV oil circuit breakers DT3L5 and DT4L4. Where possible, other asset replacements are also incorporated such as component upgrades to meet present day Hydro One standards. This investment will maintain the reliability of supply between North Bay and Petawawa.	6	2	13	2024
Fort Frances TS	The main assets driving this investment are the T4 step-down transformer, AC/DC SS transfer schemes, three 230kV oil circuit breakers and EOL protections. This investment will maintain reliability of supply to customers in northwestern Ontario in the Fort Frances area, and maintain the reliability and integrity of power flow through the international transmission connection with the state of Minnesota, United States.	1	3	46	2024
Buchanan TS	Replacement of end of life autotransformers T3, T4 and their associated protections and disconnected switches as well as upgrade the end of life DC station service transfer scheme. This investment will maintain reliability of the bulk system in the London area. However, transformer T4 has recently failed and is being replaced under the demand capital failure replacement program in 2019.	2	0	10	2025

Station Name	Scope and Impacts	Transformer Repl.	Breakers Repl.	Prot. Repl.	In Service Year
Middleport TS	Replacement of end of life autotransformer T6 and associated protections, disconnected switches and surge arrestors.	1	0	6	2025
Manby TS	As per the preliminary condition assessment, this investment will result in replacement of the end-of-life, Polychlorinated Biphenyl (PCB) contaminated T7, T9, and T12 230kV 250MVA autotransformers and T13 230kV 93MVA transformer as well as other deteriorated, end-of-life assets including circuit breakers, protection equipment and other ancillary assets. This investment will result in improved overall station reliability and eliminate operational risks associated with operating end-of-life equipment, eliminate PCB contaminated equipment in the station in order to comply with environmental regulations and will maintain reliability of supply to Toronto Hydro customers in downtown and west Toronto.	4	12	28	2025
Algoma TS	This investment is driven by the need to replace a number of assets that are near end of life at Algoma TS. The main assets driving this investment are transformers T5 and T6, five 115kV oil circuit breakers AL1, AL4, HL2, HL4, and L1L2 and AC and DC transfer schemes. Four of the five 115kV oil circuit breakers identified for replacement have confirmed high levels of PCBs in their bushings and need to be replaced by 2025. This investment will maintain the reliability of supply between northern and southern Ontario.	2	5	0	2025
Porcupine TS	This investment is driven by the need to replace a number of assets that are near end of life at Porcupine TS. The main assets driving this investment are transformers T3, T4 and T8 as well as station service transformers. This investment will maintain the reliability of supply in the Timmins area.	3	0	29	2025

Station Name	Scope and Impacts	Transformer Repl.	Breakers Repl.	Prot. Repl.	In Service Year
Beach TS	This investment is driven by the need to replace a number of assets that are near end of life at Beach TS. Preliminary assessments indicate step down transformers T5, T6 and auto transformers T7, T8 along with non-arc proof metalclad switchgear and associated protection and control equipment are at end of life and require replacement to ensure supply reliability to Alectra Utilities and overall bulk system operation are maintained.	4	22	8	2027

SR-04 Bulk Station Switchgear and Ancillary Equipment Replacement Projects

Start Date:	Q2 2017	**Priority:**	Medium
In-Service Date:	Q2 2027	**3 Year Test Period Cost ($M):**	90.0
Trigger(s):	Strategic, System Renewal		
Outcomes:	Ensure compliance, system reliability, customer satisfaction, operational efficiencies and reduce maintenance costs		

A. OVERVIEW

Bulk Station Switchgear and Ancillary Equipment Replacement Projects (the "Projects") are primarily switchgear replacement projects that involve the replacement of bulk transmission station circuit breakers, which includes circuit breakers rated greater than 100 kV and can be oil, air-blast, Gas Insulated Switchgear ("GIS") or Sulfur Hexafluoride ("SF6") type, that are at the end of their life and whose risk has been rated as high or very high in accordance with the asset risk assessment. The Projects might also involve the replacement of ancillary equipment (e.g. AC and DC station service equipment, disconnect switches, instrument transformers, etc.) where needed. Prior to replacement, Hydro One will perform the asset risk assessment to ensure that these assets are also at the end of their life and their condition or other factors warrant the replacement.

The bulk transmission system is the "backbone" of Ontario electricity system. Bulk power flows through the 500kV, 230kV, and 115kV transmission systems. A circuit breaker is a mechanical switching device that is capable of carrying and interrupting electrical current under normal and abnormal conditions. During abnormal conditions, circuit breakers are capable of operating rapidly to interrupt high current thereby minimizing its effect on the rest of the system. As a licensed transmitter operating transmission facilities greater than 100 kV, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards adopted by North American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating

Council ("NPCC"). Furthermore, Hydro One transmission customers include large electricity generators, large industrial end-users and the majority of Ontario's Local Distribution Companies ("LDC"). In light of the foregoing, it is apparent that there is a heightened need to ensure that this critical asset of the bulk electricity system is in a good condition and perform reliably.

The Projects pacing has been influenced by the assessment of equipment condition and in consideration of operational effectiveness, customer preferences, and safety concerns. Based on Hydro One's bulk station breaker demographic profile, it is forecasted an increasing number of units will age beyond expected service life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Projects.

Hydro One has evaluated various alternatives for the Projects, as described below, and concluded that replacing the deteriorated bulk station breakers is the most cost effective and efficient undertaking. The projected costs of the Projects are estimated to be $90.0 million over the 2020-2022 test period.

B. NEEDS AND OUTCOME

Investment Need

As discussed in TSP Section 2.2.1, Hydro One has a thorough and ongoing asset management process that involves monitoring and reviewing transmission assets and assessing their risk. Hydro One's asset strategy is to proactively inspect and monitor the breaker fleet. This allows Hydro One to manage maintenance needs and assess the breaker's associated risk to determine the need for asset replacement. Assessments to repair or replace breakers are done on an individual basis. The assessment is based on risks identified from demographics, condition, environmental factors, utilization, performance, obsolescence, costs comparison between refurbishment and replacement, and other lifecycle considerations.

Hydro One's transmission system includes 293 stations. Hydro One has established a recurring 7-10 year assessment cycle that enables all necessary renewal work to be performed at each of the 293 transmission stations during the cycle. The goal of each asset assessment is to ensure that the assets are not deteriorated, there are no risks that may compromise the reliability of the system, and they do not pose any safety or and/or environmental risk. All assets at a given station are assessed at the same time with a particular focus to transformers, breakers, and protection & control systems – as these are the most critical assets in the system and have a direct impact on a customer. If the assessment identifies multiple key station assets (i.e. transformers, breakers and protection and control equipment) whose risk warrants a replacement, Hydro One then pursues an integrated approach. The asset replacements are bundled into a single integrated station-centric investment project with the main components being identified as the driver for the project. This integrated approach is further described in SR-02**.** In the case where only the breakers are identified as the main asset for replacement along with a small subset of other minor station assets, the station is identified as a candidate for a breaker-focused replacement project.

Hydro One has 1,569 bulk station breakers in service. Currently, 16% of Hydro One bulk station breaker population is beyond their ESL. Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions. Assuming no replacement, Hydro One anticipates that 381 units (24% of the bulk station breaker population) will exceed their ESL by 2024, and 493 units (31% of the population) will exceed their ESL by 2029.

Asset condition is one of several drivers for breaker replacement. Breaker condition is monitored through information gathered during preventative inspection and maintenance activities. Hydro One performs routine maintenance and replaces breakers that are obsolete, pose safety risks, operate at or above their nameplate rating, have unacceptable performance and a poor environmental footprint. Poor performance is judged based upon the likelihood of the equipment contributing to load interrupted or unsupplied energy to the customer. Poor environmental footprint is judged based on Polychlorinated Biphenyl (“PCB”) levels in excess of legislated requirements. The following issues are examples that have been observed by Hydro One as part of its breaker risk assessment that warrants the replacement of the breakers that are the subject of the Projects:

- As breakers age, their O-rings and gaskets slowly degrade, thereby causing leaks. The leaks will result in a lower pressure and a path for moisture ingress. This condition over time can result in lower dielectric strength in the breaker and potential for internal flashover which could result in an explosive failure of the breaker.
- Some of the Hydro One fleet of breakers are no longer supported by vendors and aftermarket parts are no longer available or are costly to acquire or fabricate. This is a significant risk factor to some first generation SF6 circuit breakers and certain types of oil circuit breakers. Strategic sparing of breakers is done through replacements where parts are difficult to procure such that removal can help sustain the remaining in-service fleet.

The assessment of the bulk station breaker fleet, as of December 2018, shows that there are 11% of the bulk station breakers that are rated at a high or very high risk, as illustrated in Figure 1.

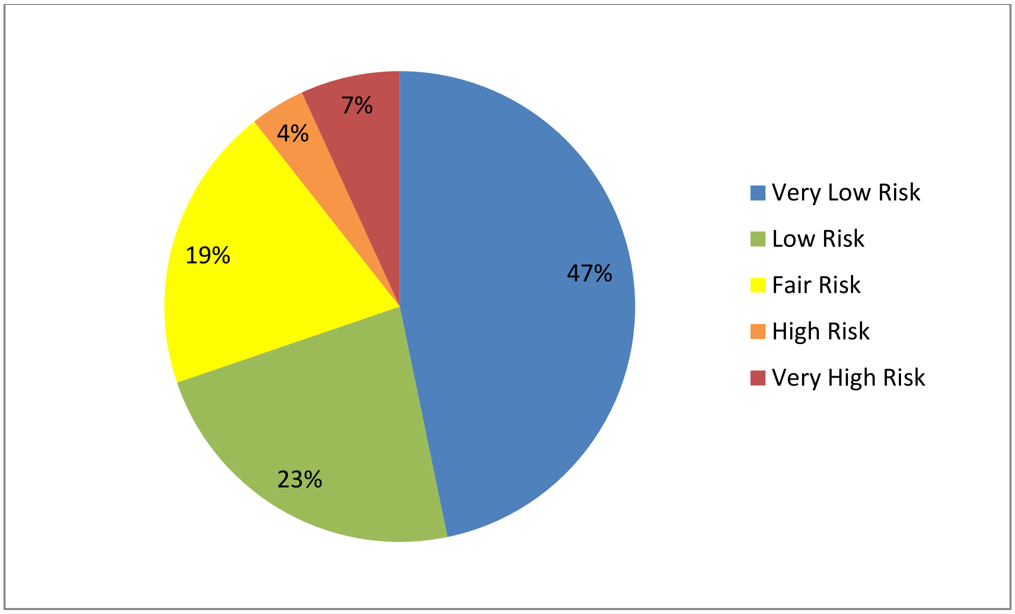

Figure 1 - Summary of Risk for Bulk Station Circuit Breakers

Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. When unexpected failure occurs, it could partially or entirely constrain generation resources and would negatively impact the reliable bulk power flows to load centres. For select transmission interties between Ontario and other jurisdictions, unexpected failures would result in decreased available import/export capacity. Failures can be catastrophic or it can be just the asset failing to do what it is intended to do (e.g. breakers can fail to operate/open when needed or they can have insulation failure and short out during operation, causing irreparable damage). Furthermore, what complicates the situation is that when a certain type of breaker approaches the end of its ESL, vendors often communicate their transition to a limited support and complete obsolescence of aged product lines. As such, it is important to stay on top of this wave of assets approaching ESL in order to avoid situations where it may become difficult to obtain parts to sustain breakers that vendors no longer support.

Breaker equipment performance is measured by assessing the duration and frequency of forced outages related to the transformer. A "forced outage" is the automatic or forced manual removal of a breaker caused directly by it or its auxiliary equipment.

Furthermore, the PCB Regulations, which came into effect in 2008, and for which amendments came into force on January 1, 2015, implemented deadlines on equipment already in use and in storage, in order to accelerate the elimination of PCBs from the Canadian environment. The PCB Regulations require all oil-filled equipment to contain PCBs less than 50 parts per million (ppm) by December 31, 2025.These requirements impact breaker oil filled bushings and the oil in the main breaker tank. It is estimated that approximately 528 breakers require PCB mitigation, which entails replacing or retro-filling the bushing (i.e., putting in new PCB free oil to bring the PCB ppm value lower). To date, Hydro One has sampled 779 breakers, with another 168 breakers being projected to contain high PCB content once sampled. This projection is based on the rate at which Hydro One has been finding high PCB concentrations in the equipment sampled to date. Using a repair vs. replace analysis, circuit breaker failures that are repairable may be considered for replacement under this program since if there is confirmed PCB content greater than the 45ppm Hydro One set limit, additional costs for the PCB mitigation will also be taken into consideration in addition to the required corrective repairs as a result of the failure.

Breaker failure could partially or entirely constrain generation resources and would lessen the reliability of bulk power flows to load centres. For transmission interties between Ontario and other jurisdictions, failures would result in decreased available import/export capacity. If left unattended, Hydro One bulk station breaker fleet will continue to degrade and the fleet demographic with breakers that are in poor or very poor condition will continue to increase, thereby resulting in more frequent and unexpected failures. Figure 2 below shows the forecast of Hydro One bulk breaker fleet with breakers reaching their ESL.

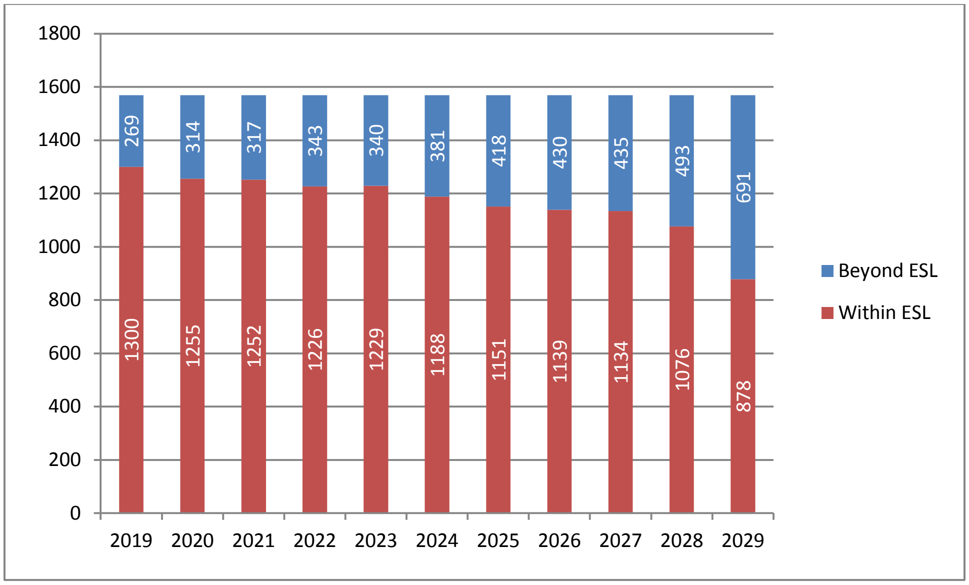

Figure 2 - Bulk Station Class Circuit Breaker Demographic Forecast – without replacement

Breaker failures can severely impact system stability, other connected equipment and employee and public safety. Consequently, it is important to ensure that the current carrying components are in good shape, the mechanical and control systems are operating within specification and that the insulating medium has not been compromised.

Investment Description

The Projects are classified as primarily breaker replacement driven. This investment will result in the replacement of switchgear and ancillary equipment at bulk transmission stations that are in a deteriorated, high risk condition where the likelihood of a failure is high. The Projects involve a series of individual projects which vary in scope and in size. The Projects target a like-for-like replacement of deteriorated bulk power breakers at various bulk transformer stations. It also addresses the replacements of select ancillary equipment such as switches, batteries, chargers as well as may additionally address site or property issues, customer issues, safety concerns, environmental compliance, and operational issues whose condition might also warrant the replacement.

Hydro One's plan for the breaker fleet replacement over the next five years has been influenced by fleet demographics, observed condition, anticipated condition, and performance factors as well as environmental concerns, as described above. Cumulatively, the Projects target the replacement of 64 breakers over the five year period at 11 stations. Further details pertaining to the Project are provided in Appendix "A" below.

Outcome

As a result of the Project, Hydro One will reduce operational risks (e.g. bottled generation, reduced transfer capability, restricted power flows) associated with the operation of end-of-life equipment; ensure compliance with NERC and NPCC requirements as well as PCB Regulations; maintain long-term bulk power flow reliability throughout the power system; maintain long-term reliability of import/export capacity on select transmission interties; and mitigate the risk of constraining generation resources.

The following table presents anticipated benefits as a result of the Project in accordance with the Ontario Energy Board's Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• Maintain reliable performance of the bulk electricity system power flows through the replacement of end of life ("EOL") equipment.
Operational Effectiveness	• Improve the operational effectiveness of bulk stations through standardization of new equipment.
Public Policy Responsiveness	• Comply with applicable regulatory and environmental requirements.
Financial Performance	• Realize cost savings by addressing multiple deteriorated assets within the station as part of the same project.

C. EXPENDITURE PLAN

As discussed above, the Project is needed to replace the bulk power breakers and ancillary equipment failure of which may compromise the reliability of supply due to the assets being deteriorated and at end of life. Hydro One planned the Project in a way that strives to complete it as effectively and efficiently as possible so to minimize the cost of performing this sustainment task.

Table 1 summarizes historical and projected spending on the aggregate project level. Since the Project consists of a multiple projects, as presented in Appendix "A", Table 1 below consolidates all the costs for individual projects and presents the total Project costs. The "Previous Years" costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	4.5	18.0	33.4	42.6	35.7	50.8	26.4	211.4
Less Removals	0.1	0.5	1.0	1.2	1.1	1.5	0.8	6.2
Gross Investment Cost	**4.5**	**17.5**	**32.4**	**41.4**	**34.6**	**49.3**	**25.6**	**205.2**
Less Capital Contributions	0.0	0.0	0.0	1.2	0.0	0.0	0.0	1.2
Net Investment Cost	**4.5**	**17.5**	**32.4**	**40.2**	**34.6**	**49.3**	**25.6**	**204.0**

[1] *Includes overhead at current rates.*

Table 2 below presents projected costs on an individual project basis. It also provides a total costs for each individual project along with the proposed in-service date.

1 **Table 2 - Detailed Project Costs**

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
Trafalgar TS	9.1	4.4	4.5	1.1	0.0	19.1	20.1	2022
Claireville TS	3.0	9.3	9.9	0.5	0.0	22.8	23.9	2022
Rabbit Lake SS	1.8	4.4	0.4	0.0	0.0	6.7	7.2	2022
Milton SS	0.5	1.9	8.1	3.1	0.0	13.5	13.9	2023
Marathon TS	2.3	7.6	7.3	1.8	0.0	19.0	19.7	2023
Mackenzie TS	0.7	3.1	7.1	5.8	1.3	17.9	18.4	2024
Merivale TS	0.0	0.2	0.6	1.8	11.6	14.2	18.9	2025
St.Lawrence TS	0.0	0.2	0.6	4.9	13.9	19.7	23.2	2025
Kenora TS	0.1	0.5	0.7	4.1	4.9	10.2	11.6	2025
Mississagi TS	0.0	0.4	0.5	2.2	9.3	12.3	15.9	2025
Lakehead TS	0.0	0.1	0.5	9.5	8.3	18.4	31.0	2027
Net Investment Cost	**17.5**	**32.4**	**40.2**	**34.6**	**49.3**	**173.9**	**204.0**	

Furthermore, the following factors also affect the capital expenditures required for the Project:

- Applicability of Ministry of the Environment, Conservation, and Parks, NERC and/or NPCC requirements;
    - PCB compliance regulations established by Environment Canada drive the cost analysis of whether to retro-fill (refill) oil equipment or replace the PCB affected equipment. The Operations, Maintenance and Administration cost to retro-fill the main tank or bushings on a circuit breaker is not deemed prudent for units approaching or beyond their ESL given the increased likelihood of failure. The preference is to proceed with a capital replacement due to the reduced rate impact and future benefit and reliability a new unit would provide.

- Complexity of project staging and outages required to facilitate work:
    - Increases the cost of planning the project
    - Increases overall duration of project (interest and overhead costs increases).

- Whether like-for-like replacements are installed in a new location or installed in-situ which may require complex contingency planning:
    - New location will require additional facilities to be installed to connect the equipment rather than re-using existing facilities (i.e. bus work and supporting structures/foundations), increases cost
    - Contingency planning can increase cost by requiring bypass installations, temporary supplies and etc.

- Site conditions and challenges:
    - Urban areas will have constraints with outage planning, construction staging and contingency planning which could add to project duration and complexity and result in higher costs (e.g. working in space-constrained stations; work

within neighborhoods where streets are congested and working hours may be constrained due to noise requirements; unique design and construction challenges; outage constraints as service still needs to be maintained amidst the required work)

Remote rural areas will increase costs due to difficulty of working on difficult terrain, difficulty accessing the station with heavy equipment, and delivery of large equipment.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: Reactive Component Replacement involves waiting for deteriorated breakers or ancillary equipment to fail and replace components on a reactive basis. Hydro One has rejected this alternative for the following reasons:

- Assets in deteriorated condition will continue to deteriorate and decline, thereby increasing the likelihood of unexpected failures. These failures might be prolonged and might result in extended equipment and customer outages which will subsequently lower System Average Interruption Duration Index and System Average Interruption Frequency Index performance.
- An increased likelihood of unexpected failures would lead to increased environmental risk due to the possibility of a release into the environment during a failure event.
- An increased likelihood of unexpected failures would lead to increased safety risk due to the possibility of a failure event being catastrophic in nature.
- There is expectation that there will be more catastrophic failures and systemic failures which based on past experience, cost more to replace compared to planned replacements due to the amount of damage, number of equipment affected and duration of outages related to these events.

- The maintenance frequency would likely increase and result in increased maintenance costs. As assets age beyond their ESL, repairs become more costly as the assets are no longer supported by vendors and aftermarket parts are no longer available or are costly to acquire or fabricate.
- Replacing reactively would lead to assets being replaced in an uncoordinated fashion. This would lead to assets only being replaced on an in-situ basis and reduce the ability to prudently address other station infrastructure. Uncoordinated fashion here is referring to planning the work in a holistic approach.
  - Many of the assets at a station are interconnected and replacing a single asset can either limit Hydro One in the design options for this replacement or cause the need for rework in the future, for example, coordinating protection replacements with breaker replacements
  - When multiple assets are reaching EOL, there is opportunity to make changes to the electric configuration to make improvements to the reliability and performance of the bulk electricity system. Uncoordinated fashion can also pertain to the mobilization of construction forces, the staging of work to minimize impact to customers (outage frequency and duration).

Alternative 2: Station Refurbishment involves the refurbishment of the entire station where significant populations of assets are in a high risk condition, before failure occurs. This alternative is only a viable solution where the other key station assets, such as transformers and switching facilities are in a deteriorated, high risk condition. This alternative has been considered for the Project and has been rejected as there is insufficient justification to proceed with a complete station refurbishment. Hydro One does not replace the transmission assets unless the asset condition warrants the replacement. Where majority of assets are EOL, this alternative may then be considered, but then the project would fall under the SR-02.

Alternative 3: Like-for-Like Planned Replacement is a preferred undertaking. It involves proactively replacing individual station components in a single integrated investment, with switchgear and ancillary equipment that are in a deteriorated, high risk condition. This alternative is recommended as it addresses the needs identified at the station to maintain the reliability of Hydro One's transmission system in the most cost effective manner, consistent with the findings of the customer engagement process. This alternative focuses on the replacement of select equipment in a like-for-like manner, unless otherwise requested to meet broader system needs.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of bulk station breaker replacement projects are: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges, or regulatory approvals. A thorough risk assessment workshop is performed during the initial project planning phase where all known risks are identified and mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize to a minimum the loss of supply to the customer. The plan might include the construction of a temporary by-passing circuit or supply of portable generation that will maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. Another example is the involvement of real estate from the project inception. It allows for the early identification of real estate issues, such as missing or inadequate land rights. Once the issue is identified, Hydro One tries to resolve it prior to execution of the project.

APPENDIX A – DETAILED PROJECT PLAN

Station Name	Scope and Impact	Breakers Repl.	Prot. Repl.	In Service Year
Trafalgar TS	Replacement of end of life of protections as well as select surge arresters, air-gas bushings, DC station service equipment, instrument transformers, and minor ancillary assets. These replacements will decrease the risk of equipment failure and contribute to maintaining bulk power supply reliability to the Greater Toronto Area.	-	44	2022
Claireville TS	Replacement of end of life protections, as well as select surge arresters, air-gas bushings, DC station service equipment, AC station service equipment, instrument transformers, and minor ancillary assets. These replacements will decrease the risk of equipment failure and contribute to maintaining bulk power supply reliability to the Greater Toronto Area.	6	28	2022
Rabbit Lake SS	Replacement of end of life breakers and protections to maintain reliability in the Kenora area.	5	23	2022
Milton SS	Replace end of life protections as well as select surge arresters, air-gas bushings, DC station service equipment, AC station service equipment, instrument transformers, and other minor ancillary assets. These replacements will decrease the risk of equipment failure and contribute to maintaining bulk power supply reliability to the Greater Toronto Area.	-	9	2023

Station Name	Scope and Impact	Breakers Repl.	Prot. Repl.	In Service Year
Marathon TS	Replacement of end of life breakers, protections, station service and instrument transformers. This investment will maintain reliability of the bulk system connection between the northern and southern Ontario.	7	8	2023
Mackenzie TS	Replacement of end of life breakers, protections, station service and instrument transformers. This investment will maintain bulk system reliability in northwestern Ontario.	6	43	2024
Merivale TS	Replacement of four 115 kV oil circuit breakers, eight 115 kV switches and the AC/ DC system as well as upgrading protection and control systems. This will maintain reliability in delivering bulk power to eastern Ontario in the Ottawa area.	4	55	2025
St. Lawrence TS	The main assets driving this investment are five 115kV oil circuit breakers (KL2,PL1, PL2, T2K and T2L1) and two 230kV oil circuit breakers (AL34 and HL34) and their associated disconnect switches are being replaced. The assets are at the end of life and replacing them will maintain reliability of bulk power delivery from New York Power Authority (NYPA) to Ontario’s high voltage networks. Implications of not completing this work include a significant risk of further equipment deterioration and declining transmission system reliability.	7	7	2025
Kenora TS	Replacement of end of life breakers, protections, station service and instrument transformers. This investment will maintain reliability in the Kenora area.	5	24	2025

Station Name	Scope and Impact	Breakers Repl.	Prot. Repl.	In Service Year
Mississagi TS	Replacement of end of life breakers, protections, station service and instrument transformers. This investment will maintain reliability of the bulk system connection between the northern and southern Ontario.	7	30	2025
Lakehead TS	Replacement of end of life breakers, protections, station service and instrument transformers. This investment will maintain bulk system reliability in the Thunder Bay area.	17	53	2027

SR-05 Load Station Transformer Replacement Projects

Start Date:	Q1 2015	**Priority:**	Medium
In-Service Date:	Q1 2026	**3 Year Test Period Cost ($M):**	352.4
Trigger(s):	System Renewal		
Outcomes:	Ensure compliance, system reliability, customer satisfaction, operational efficiencies and reduce maintenance costs		

A. OVERVIEW

Load Supply Station Transformer Replacement Projects (the “Projects”) are primarily a series of individual transformer replacement projects that involves the replacement of load supply station transformers (e.g. step-down transformers) that are at or beyond the end of their life. The Project might also involve the replacement of select breakers, protection and control systems and other ancillary equipment, where needed. Prior to replacement, Hydro One will perform an asset risk assessment to ensure that these additional assets are also at the end of their life and that their condition or other factors warrant the replacement.

Load supply stations, via the step-down power transformers, transfer power from higher voltages to lower voltages to facilitate the distribution of power via the downstream distribution network. The main Hydro One customers at the load supply stations are LDCs and large industrial customers. The LDCs that are served by Hydro One’s transmission system serve most of Ontario’s residential, commercial, institutional and small industrial end-users. The end-user facilities that are indirectly affected by the reliability and performance of Hydro One’s transmission system include such critical infrastructure as telecommunications systems, water and wastewater treatment facilities, hospitals and other health care facilities, airports and transportation systems, schools and universities, financial services systems, etc. In essence, Hydro One’s load supply stations and step-down power transformers provide the electrical energy necessary to power the provincial economy and meet society’s daily needs. In light of the foregoing, it is apparent that there is a heightened need to ensure prudent and proactive replacement of step-down power transformers as warranted by condition assessments and other factors.

The Project pacing has been influenced by load supply transformer fleet demographics, observed condition, anticipated condition, and performance factors as well as environmental and safety concerns, as described below. Based on Hydro One's overall transformer demographic profile, it is forecasted that an increasing number of units will age beyond Expected Service Life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases supply reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Project.

Hydro One has evaluated various alternatives for the Project, as described below, and concluded that replacing deteriorated load supply station transformers is the most cost effective and efficient undertaking. The projected costs of the Projects are estimated to be $352.4 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

As discussed in TSP Section 2.1.2, Hydro One has a thorough and ongoing asset management process that involves monitoring and reviewing transmission assets and assessing needs. Hydro One's transformer asset strategy is to proactively inspect and monitor the transformer fleet. This allows Hydro One to manage maintenance needs and assess the transformer's condition as a factor to determine the need for asset refurbishment or replacement. Assessments to repair or replace transformers are done on an individual basis. The assessment is based on risks identified from demographics, condition, environmental factors, utilization, costs comparison between refurbishment and replacement, and other lifecycle considerations. Units that are considered high risk, or with known manufacturer defects/obsolesce, or with anticipated higher repair costs are prioritized for replacement.

Hydro One's transmission system includes 293 stations. Hydro One has established a recurring 7-10 year assessment cycle that enables all necessary renewal work to be performed at each of the 293 transmission stations during the cycle. The goal of each asset assessment is to ensure that the assets are not deteriorated, there are no risks that may compromise the reliability of the system, and they do not pose any safety or and/or environmental risk. All assets at a given station are assessed at the same time with a particular focus to transformers, breakers, and protection and control systems – as these are the most critical assets in the system and have a direct impact on a customer. If the assessment identifies multiple station assets (i.e. transformers, breakers and protection and control equipment) whose condition warrants a replacement, Hydro One then pursues an integrated approach. The asset replacements are bundled into a single integrated station-centric investment project with the main components being identified as the driver for the project. This integrated approach is further described in SR-02**.** In the case where only transformers are identified as the main asset for replacement along with a small subset of other minor station assets, the station is identified as a candidate for a transformer-focused replacement project.

As of December 2018, Hydro One has 576 load supply station step-down transformers in service. Currently, 24.4% of the Hydro One load supply station step-down transformer population is beyond ESL. Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions. The average age of the load supply station transformer fleet is 29 years. Assuming no replacements, Hydro One anticipates that 37.9% of the load supply station transformer population will exceed their ESL by 2024, and 48.6% of the population will exceed their ESL by 2029.

Transformer condition is a leading predictive indicator of equipment reliability and usually the main driver for replacement. Condition is determined by industry standard diagnostic testing which includes routine transformer oil testing and other maintenance examinations. Transformer insulation generally degrades as a function of time and other operational factors (i.e. loading levels) and this degradation is irreversible, ultimately requiring asset replacement. Furthermore, transformer ESL has a direct correlation to anticipated insulation condition. Within the industry, there is correlation between the highly flammable and volatile chemical compound - furan and the degree of polymerization of insulation paper. The degree of polymerization of the paper is an indicator of insulation strength and condition. Furan is a chemical that can be detected via oil samples. Furan is a by-product of paper degradation as it ages and decomposes. Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. Assessment of the load supply station transformer fleet’s condition based on oil analysis results shows that approximately 18% are rated high or very high risk, as illustrated in Figure 1.

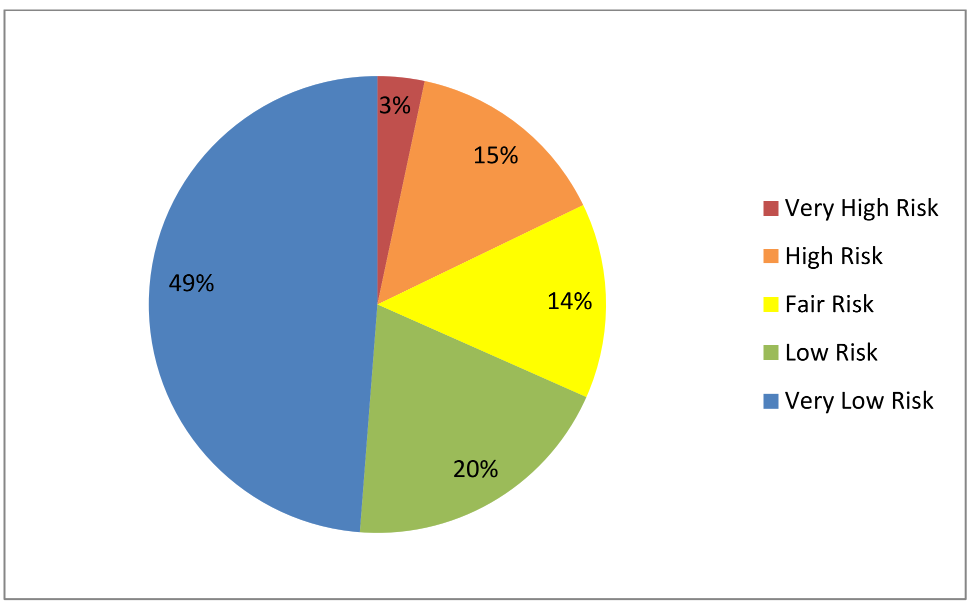

Figure 1 - Condition Summary of Load Supply Station Transformer Fleet

Transformer equipment performance is measured by assessing the duration and frequency of forced outages related to the transformer. A "forced outage" is the automatic or forced manual removal of a transformer caused directly by it or its auxiliary equipment. From a fleet wide perspective, transformer forced outages have been a major cause of customer delivery point interruptions over the past 10 years, representing 13% of these equipment-caused events. Fleet wide, over the last 10 years, Hydro One has experienced an average annual Class 1 failure rate of 0.51%. Class 1 failures are unpredictable, catastrophic and irreparable. An example is the 2011 Richview T7 and T8 failures, where both transformers were engulfed in fire. The smoke that it produced severely impaired traffic on Highway 401 during rush hour. Table 1 below summarizes the number of Class 1 failures by voltage class.

Table 1 - Transformer Annual Class 1 Failure Rates over the Past 10 Years (2008-2017) in Percentage of Transformer Population

Year	115kV	230kV	500kV	5 Year Average Annual Failure Rate, All Voltage classes
2008-2012	0.40%	0.37%	1.41%	0.44%
2013-2017	0.56%	0.41%	2.44%	0.59%
10 Year Average Annual Failure Rate	0.48%	0.39%	1.92%	0.51%

Regarding oil leaks, approximately 42% of the load supply transformer fleet has confirmed oil leaks via visual inspections, with 11% classified as major leakers as summarized in Figure 2 below. Based on Hydro One's experience, new leaks will appear in approximately 1% of the fleet's population per year, most commonly as a result of gasket deterioration over time. Transformer leaks not only create environmental concerns, but also generate reliability issues, as in-service transformers may be forced out due to low oil levels. Active leaks also provide a path of moisture ingress into the transformer's internal winding. Finally, severe oil leaks and frequent oil top ups also compromise the accuracy of condition assessments because they dilute the oil and may result in a false improved oil test result.

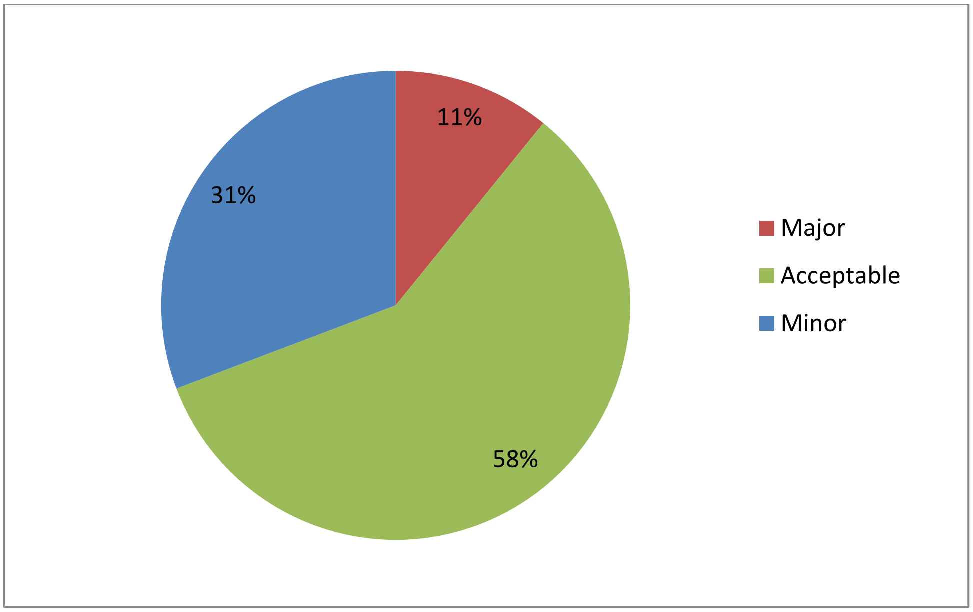

Figure 2 - Load Station Transformer Leak Assessment

Furthermore, the Polychlorinated Biphenyl (“PCB”) Regulations, which came into effect in 2008, and for which amendments came into force on January 1, 2015, implemented deadlines on equipment already in use and in storage, in order to accelerate the elimination of PCBs from the Canadian environment. The PCB Regulations require all oil-filled equipment to contain PCB levels of less than 50 parts per million (“ppm”) by December 31, 2025. The PCB Regulations impact transformer oil filled bushings. From a fleet wide perspective, as of December 2018, up to 43% of Hydro One’s transformer oil-filled bushings may require work related to PCB testing verification or replacements. When high PCB levels are present in a transformer approaching end of life (“EOL”), it may be more economical to slightly advance replacement than to make repairs to resolve high PCB levels on a unit near EOL.

With regards to failure risk, under normal operating conditions, failure of one step-down power transformer at a load supply station will usually not result in load interruptions due to the redundant nature of the load supply station’s configuration. However, the load supply station would be put into a more vulnerable state for potentially 2-4 months until a replacement step-down power transformer could be installed to restore redundancy (i.e. backup). As a result, there would be an elevated risk to supply reliability while in this vulnerable state of lost redundancy (i.e. lost backup). Furthermore, at many load supply stations, a significant proportion of load may be ‘stranded’, or unable to be easily supplied from another station, if necessary. Consequently, loss of a step-down transformer combined with stranded load at a station would further heighten vulnerability and reliability risk. During this state of vulnerability, if the remaining companion step-down transformer were to be removed from service due to other power system issues, such as a high voltage line outage, momentary to lengthy load interruptions would result depending on the issue. If the remaining companion step-down transformer itself were to fail during this state of vulnerability, it is possible that stranded load could remain unsupplied for an extended time until another feasible emergency measure is implemented. Generally, if left unattended, the Hydro One load supply station step-down transformer fleet will continue to degrade and the fleet demographic with transformers that are in a high or very high risk state will continue to increase, thereby resulting in more frequent and unexpected failures.

Investment Description

The Project is classified primarily as a transformer replacement project. The Project involves a series of individual projects that target a like-for-like replacement of deteriorated load supply power transformers at various load supply transformer stations. The Project also addresses replacements of select breakers, protection and control systems, switches, batteries, chargers, instrument transformers and may additionally address site or property issues, customer issues, safety concerns, environmental compliance, and operational issues.

Hydro One's plan for the transformer fleet replacement over the next five years has been influenced by fleet demographics, observed condition, anticipated condition, and performance factors as well as environmental and safety concerns, as described above. Cumulatively, the Project targets the replacement of 74 transformers, 143 breakers, and 591 protection systems over the five year period at 40 stations, as further detailed in Appendix "A" below.

Outcome

As a result of the Project, Hydro One will reduce operational risks (e.g. local area supply risk, momentary/extended load interruption risk) associated with the operation of end-of-life equipment; ensure compliance with government and industry regulations; maintain long-term supply reliability to downstream customers; and mitigate the risk of local area outages.

The following table presents anticipated benefits as a result of the Project in accordance with the OEB's Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• Maintain long-term supply reliability to downstream customers through the replacement of end-of-life equipment.
Operational Effectiveness	• Maintain operational flexibility of the load supply electricity system through the replacement of end-of-life equipment.
Public Policy Responsiveness	• Comply with applicable regulatory and environmental requirements
Financial Performance	• Realize cost savings by addressing multiple deteriorated assets within the station as part of the same project.

C. EXPENDITURE PLAN

As discussed above, the Project is needed to replace load supply power transformers as well as other load supply station assets that may compromise the reliability of supply due to the assets being deteriorated and at EOL, which may lead to unexpected failures.

Hydro One has planned the Project in a way that strives to complete it as effectively and efficiently as possible so as to minimize the cost.

Table 2 summarizes historical and projected spending on the aggregate project level. Since the Project consists of multiple projects, as presented in Appendix "A", Table 2 below consolidates all the costs for individual projects and presents the total Project costs. The "Previous Years" costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024.

Table 2 - Total Investment Cost

($ Millions)	**Prev. Years**	**2020**	**2021**	**2022**	**2023**	**2024**	**Forecast 2025+**	**Total**
Capital[1] and Minor Fixed Assets	91.1	94.0	136.4	133.4	184.0	206.2	67.0	912.0
Less Removals	3.3	2.8	4.1	4.0	5.5	6.2	2.0	27.8
Gross Investment Cost	**87.8**	**91.2**	**132.3**	**129.4**	**178.5**	**200.0**	**65.0**	**884.1**
Less Capital Contributions	0.0	0.5	0.0	0.0	0.6	0.6	0.0	1.6
Net Investment Cost	**87.8**	**90.7**	**132.3**	**129.4**	**177.9**	**199.5**	**65.0**	**882.5**

[1] *Includes overhead at current rates.*

1 Table 3 below presents projected costs on an individual project basis. It also provides a
2 total costs for each individual project along with the proposed in-service date.

4 **Table 3 - Detailed Project Costs**

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
Hawthorne TS	3.2	0.0	0.0	0.0	0.0	3.2	41.2	2020
Strachan TS	3.9	0.0	0.0	0.0	0.0	3.9	11.7	2020
Stanley TS	14.0	8.9	0.0	0.0	0.0	22.9	33.5	2021
Minden TS	12.9	5.0	0.0	0.0	0.0	17.8	31.2	2021
Main TS	12.9	13.0	0.0	0.0	0.0	25.9	29.8	2021
King Edward TS	4.7	3.4	0.0	0.0	0.0	8.1	12.7	2021
Hanlon TS	1.8	12.4	4.9	0.0	0.0	19.2	19.9	2022
Wingham TS	3.4	10.8	3.9	0.0	0.0	18.2	19.0	2022
Kingsville TS	8.6	8.8	2.3	0.0	0.0	19.7	20.9	2022
Thorold TS	7.7	5.8	2.1	0.0	0.0	15.5	18.4	2022
Stratford TS	0.0	0.3	1.6	6.9	0.0	8.8	8.8	2023
Cedar TS	0.0	2.0	7.1	2.7	0.0	11.9	11.9	2023
Crowland TS	0.7	2.9	12.5	4.8	0.0	20.9	21.1	2023
Murray TS	0.8	4.8	8.7	3.0	0.0	17.4	18.1	2023
Orangeville TS	5.1	15.6	14.9	3.9	0.0	39.5	40.6	2023
Bridgman TS	5.6	13.2	11.0	2.6	0.0	32.3	33.8	2023
Parry Sound TS	1.0	6.6	6.6	1.7	0.0	15.9	15.9	2023
Moose Lake TS	0.7	3.3	9.0	8.1	2.0	23.1	23.4	2023
Lauzon TS	0.8	3.8	12.6	12.1	3.0	32.3	32.5	2024
Port Hope TS	0.0	0.5	2.6	6.3	2.2	11.6	11.6	2024
Longueuil TS	0.2	0.7	2.4	10.2	3.9	17.4	17.4	2024
Clarke TS	0.2	0.6	1.4	9.3	6.5	18.0	19.2	2025
Preston TS	0.1	0.4	1.1	6.0	11.5	19.0	24.1	2025
Birmingham TS	0.2	0.8	3.1	10.1	9.6	23.8	26.3	2025
Newton TS	1.0	2.0	3.0	3.6	8.0	17.6	21.0	2025
Palermo TS	0.0	0.2	0.8	4.4	19.1	24.6	32.1	2025
Gage TS	0.0	0.2	0.7	2.6	11.3	14.8	19.2	2025
Bermondsey TS	0.0	0.5	0.9	5.8	13.7	20.8	25.7	2025
Leslie TS	0.0	0.5	1.4	9.4	17.5	28.9	34.8	2025
Wilson TS	0.0	0.5	1.8	11.9	11.8	26.0	29.1	2025

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
Charles TS	0.2	0.6	1.3	9.0	7.6	18.7	20.4	2025
Duplex TS	0.2	0.6	3.4	13.3	13.6	31.0	34.7	2025
Woodbridge TS	0.0	0.6	0.6	3.6	4.4	9.1	10.4	2025
Bathurst TS	0.0	0.6	0.7	4.0	6.1	11.4	13.4	2025
Strachan TS	0.0	0.5	0.6	2.6	8.1	11.7	14.8	2025
Wallace TS	0.2	0.6	1.1	7.8	7.9	17.5	19.6	2025
Bilberry Creek TS	0.0	0.2	0.6	1.2	8.2	10.2	13.5	2025
Russell TS	0.0	0.2	0.5	0.7	4.4	5.7	7.5	2025
Elliot Lake TS	0.5	0.8	3.6	8.4	7.0	20.3	22.0	2025
Fairchild TS	0.0	0.2	0.6	1.8	12.3	15.0	21.5	2026
Net Investment Cost	**90.7**	**132.3**	**129.4**	**177.9**	**199.5**	**729.8**	**882.5**	

Furthermore, the following factors also affect the capital expenditures required for the Project:

- Applicability of government and industry regulations:
  - When a transformer is replaced, there are requirements from the Ministry of the Environment, Conservation and Parks ("MOECP") for spill containment and oil/water separators to mitigate the risk to the environment if oil is spilled.
  - PCB compliance regulations established by Environment Canada drive the cost analysis of whether to retro-fill (refill) oil equipment or replace the PCB affected equipment. The Operations, Maintenance and Administration ("OM&A") cost to retro-fill the main tank on a power transformer is not deemed prudent for units approaching or beyond their ESL given the increased likelihood of failure. The preference is to proceed with a capital replacement due to the reduced rate impact and future benefit and reliability a new unit would provide.

- Complexity of project staging and outages required to facilitate work:
  - Increase planning costs portion of the project.

    - Increases overall duration of project (interest and overhead costs increases).

- Whether like-for-like replacements are installed in a new location or installed in-situ requires complex contingency planning:
    - New location will require additional facilities to be installed to connect the equipment rather than re-using existing facilities (i.e. bus work and supporting structures/foundations), increases cost.
    - Contingency planning can increase cost by requiring backup transformer installations, temporary supplies, etc.

- Site conditions and challenges:
    - Urban areas have many constraints such as outage planning, construction staging and contingency planning which could add to project duration and complexity and result in higher costs (e.g. working in space-constrained stations; work within neighborhoods where streets are congested and working hours may be constrained due to noise requirements; unique design and construction challenges; outage constraints as service still needs to be maintained amidst the required work).
    - Remote rural areas will increase costs due to difficulty of working on difficult terrain, difficulty accessing the station with heavy equipment, delivery of large equipment, etc.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: Reactive Component Replacement involves waiting for deteriorated condition transformers, breakers, or ancillary equipment to fail and replace components on a reactive basis. This alternative is more costly not only for Hydro One but also for impacted customers. Hydro One has rejected this alternative for the following reasons:

- Assets in deteriorated condition will continue to deteriorate and decline, thereby increasing the likelihood of unexpected failures. These failures might be prolonged and might result in extended equipment and customer outages which will subsequently lower System Average Interruption Duration Index and System Average Interruption Frequency Index performance.
- An increased likelihood of unexpected failures would lead to increased environmental risk due to the possibility of a release into the environment during a failure event.
- An increased likelihood of unexpected failures would lead to increased safety risk due to the possibility of a failure event being catastrophic in nature.
- Since these replacements would likely be executed on an emergency basis, it would constantly result in the reprioritization of planned work and inefficient redeployment of resources.
- This alternative limits the ability to account for future requirements and has a high risk of re-work and future costs.
- This strategy is likely to increase OM&A costs, decrease equipment performance and might impact the safety of personnel on site.

Alternative 2: Station Refurbishment involves the refurbishment of the entire station where significant populations of assets are in a high risk condition, before failure occurs. This alternative is only a viable solution where the other key station assets, such as transformers and switching facilities are in a deteriorated, high risk condition. This alternative has been considered for the Project and has been rejected as there is insufficient justification to proceed with a complete station refurbishment. Hydro One does not replace the transmission assets unless the asset condition or other factors warrants the replacement. Where the majority of assets are EOL, this alternative may then be considered, but then the project would fall under the SR-2.

Alternative 3: Like-for-Like Planned Replacement is a preferred undertaking. It involves proactively replacing individual station components in a single integrated investment, with transformers being the primary project driver and additional station assets such as switchgear and ancillary equipment being included that have a deteriorated, high risk condition. This alternative is recommended as it addresses the needs identified at the station to maintain the reliability of Hydro One's transmission system in the most cost effective manner, consistent with the findings of the customer engagement process. This alternative focuses on the replacement of select equipment in a like-for-like manner, unless otherwise requested to meet broader system needs.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of load supply station transformer replacement projects are: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges, or regulatory approvals. A thorough risk assessment workshop is performed during the initial project planning phase where all known risks are identified and a mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize the risk of supply loss to the customer. The plan might include the installation of a temporary transformer or supply of portable generation that will maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. Another example is the involvement of real estate from the project inception. It allows for the early identification of real estate issues, such as missing or inadequate land rights. Once the issue is identified, Hydro One tries to resolve it prior to execution of the project.

1 **APPENDIX A – DETAILED PROJECT PLAN**

Station Name	Scope and Impact	Transformers Replaced	Breakers Replaced	Protections Replaced	In Service Year
Hawthorne TS	This investment will replace two end-of-life power transformers, three 500kV circuit breakers, and associated protections, controls and telecom facilities. These facilities now require replacement to prevent further equipment condition deterioration and to address the increased risks of equipment failures. The station transforms 230kV into 44 kV and supplies approximately 70MW to Hydro Ottawa Limited, and failure of these assets would adversely affect Hydro Ottawa customers and supply capability to the Ottawa area.	2	3	4	2020
Strachan TS	This investment will replace the deteriorated, EOL T12 transformer and other end-of-life station assets and infrastructure including switches, surge arrestors, site drainage, protection equipment and potential transformers. Failure of these assets would adversely impact the reliability of supply to Toronto Hydro customers. In addition, at the request of Toronto Hydro to meet future supply demand, the T12 transformer will be replaced with a larger standard Hydro One unit. The T12 power transformer has confirmed PCB contamination in its high voltage bushings. This investment will replace end-of-life equipment, meet the customer's request for increased capacity and maintain the reliability of supply.	1	0	12	2020
Stanley TS	The following equipment at Stanley TS is obsolete, at EOL and in degraded condition requiring replacement; transformer T2, medium voltage switching facilities and associated protection and control equipment. Replacing the equipment identified will maintain supply reliability to Niagara Peninsula Energy Inc. and decrease risk of equipment failure.	1	8	41	2021
Minden TS	Replace T1 and T2 transformers at Minden TS which is somewhat remotely located with challenging ground conditions. T1 and T2 are identified for replacement due to leak points on older units and signs of insulation degradation. In addition, the 44kV switchyard will be rebuilt including the associated protection & control equipment. The 44kV switchyard is a legacy structure that requires expanded outage zones to complete maintenance or reconstruction activities. The AC station service equipment and eleven end-of-life 230kV disconnects will also be replaced. These replacements will decrease the risk of equipment failure and contribute to maintaining supply reliability to Hydro One Distribution customers in the Minden area.	2	0	8	2021

Station Name	Scope and Impact	Transformers Replaced	Breakers Replaced	Protections Replaced	In Service Year
Main TS	Replace T3 & T4 transformers at Main TS which is a space-constrained urban station located in Toronto. T3 was identified for end-of-life replacement due to leaks, overheating and a rising dissolved gas trend indicating internal degradation. T4, which is beyond expected service life, is currently planned for replacement due to a customer request for increased station capacity. In addition, ancillary equipment such as switches and minor instrument transformers are also identified for replacement. These replacements will decrease the risk of equipment failure, increase station capacity as per a customer request, and contribute to maintaining supply reliability to downtown Toronto Hydro customers.	2	0	0	2021
King Edward TS	King Edward TS is a major load centre for the Ottawa area serving ~80MW of customer load with projected load growth to ~100MW. Hydro Ottawa has requested transformer T3 be upgraded to 100MVA. By 2021, T3 will be replaced along with EOL protections and batteries in order to maintain the reliability of supply to Hydro Ottawa Limited. Not proceeding with this work could increase the risk of equipment failure resulting in higher delivery point interruptions.	1	8	21	2021
Hanlon TS	T1 and T2 supply Guelph Hydro with approximately 22 MW and are to be replaced in order to maintain equipment reliability and long term reliability of supply. These units are in a degraded condition and are at EOL. All the associated obsolete protection and control facilities are also to be replaced. EOL AC and DC station services are also to be addressed in this investment to ensure reliable performance for station equipment.	2	0	27	2022
Wingham TS	This investment is driven by the need to replace a number of assets that are near EOL at Wingham TS. The main assets driving this investment are power transformers T1 and T2, and 15 equipment protections. This investment will maintain the reliability of supply to Hydro One Distribution customers in the Wingham area.	2	0	15	2022
Kingsville TS	This investment will replace transformers T1, and T3 with a new 83 MVA 115/28kv transformers as transformers T1, T2 and T4 are at EOL. T2 and T4 were replaced in 2018 due to their failing condition leading to a more immediate need for replacement. In addition, six oil circuit breakers in the 27.6kV switchyard will be replaced as well as other minor components such as insulators, AC and DC station service equipment and protection & control equipment. These replacements will decrease the risk of equipment failure and contribute to maintaining supply reliability to customers in the Kingsville area.	2	6	25	2022

Station Name	Scope and Impact	Transformers Replaced	Breakers Replaced	Protections Replaced	In Service Year
Thorold TS	The following equipment at Thorold TS is at EOL, in degraded condition and requires replacement: transformer T1, non-arc proof metalclad medium voltage switchgear, and all associated protection and control equipment. Replacing the equipment identified will maintain supply reliability in the Thorold area, decrease the risk of equipment failure and address safety risk posed by medium voltage switchgear.	1	12	33	2022
Stratford TS	This investment will replace the end of life transformer T1 at Stratford TS. The transformer is will be operating past ESL in 2020 and has major oil leaks requiring significant effort to repair. The driver for this replacement is the need for leak reduction work and other preventative maintenance activities.	1	0	0	2023
Cedar TS	This investment will replace the end of life transformer T7 and T8 at Cedar TS. Both units are operating beyond their expected service life and oil tests have shown that they are in poor condition. Replacing these units will maintain supply reliability to load customers in the Guelph area.	2	0	0	2023
Crowland TS	Transformers T5 and T6 have been identified for replacement due to various factors including condition, performance and expected service life. The replacement of T5 and T6 transformers will ensure reliability of supply to customer Welland Hydro.	2	0	4	2023
Murray TS	Based on preliminary assessment, the following equipment at Murray TS has been identified as EOL, obsolete and requiring replacement; transformer T14, Y1Y2 non-arc proof medium voltage metalclad switching facilities, associated protection and control equipment. Replacing the equipment identified above in a single integrated investment will maintain supply reliability to Niagara Peninsula Energy Inc., and Hydro One Distribution customers along with decrease risk of equipment failure.	1	9	68	2023

Station Name	Scope and Impact	Transformers Replaced	Breakers Replaced	Protections Replaced	In Service Year
Orangeville TS	Replace EOL, non-standard T1 and T2 transformers at Orangeville TS due to significant leaks on these older units and their declining condition leading to reliability and environmental concerns. In addition, replace Orangeville T3 & T4 units, which are relatively advanced in age, to facilitate the optimal replacement all four transformers (T1, T2, T3, & T4) with standard transformers while maintaining existing capacity. This replacement strategy delivers reliability, spares/inventory, and financial advantages by avoiding the purchase of custom transformers and avoiding the need to purchase a dedicated custom spare transformer. In addition, select switchgear, instrument transformers, and protection & control equipment have been identified for replacement. This replacement plan will decrease the risk of equipment failure and contribute to maintaining supply reliability to Orangeville Hydro and Hydro One Distribution customers in the Orangeville area.	4	2	12	2023
Bridgman TS	Replace T11, T12, T13, and T14 transformers at Bridgman TS which is a space-constrained urban station located in Toronto. These transformers were identified for replacement due to oil leaks and internal insulation degradation. Spill containment for all four units is not up to current standards and presents an environmental risk. In addition, other end-of-life ancillary equipment such as switches, insulators, instrument transformers and other minor assets & infrastructure are also identified for replacement. These replacements will decrease the risk of equipment failure and contribute to maintaining supply reliability to midtown Toronto Hydro customers.	4	0	0	2023
Parry Sound TS	This investment is driven by the need to replace assets that are near EOL at Parry Sound TS. The main assets driving this investment are power transformer T1 and T2, equipment protections and DC station service. Other asset replacements and upgrades have been incorporated into this investment. This investment will maintain the reliability of supply to Hydro One Distribution customers in the Parry Sound area.	2	0	0	2023
Moose Lake TS	This investment is driven by the need to replace a number of assets that are near EOL at Moose Lake TS. The main assets driving this investment are power transformers T2 and T3, two medium voltage circuit breakers and 31 equipment protections. This investment will maintain the reliability of supply to Atikokan Hydro Inc.	2	2	27	2023

Station Name	Scope and Impact	Transformers Replaced	Breakers Replaced	Protections Replaced	In Service Year
Lauzon TS	Based on field testing the T6 and T8 autotransformers are verified to be deteriorating and are to be replaced to maintain the long term reliability of supply to Hydro One Distribution and EnWin Utilities in the Tecumseh and Windsor areas. Two low voltage circuit breakers are in a degraded condition and an additional breaker has high levels of PCBs. These breakers are to be replaced to maintain equipment reliability, minimize unplanned outages and to comply with regulatory requirements. Two additional high voltage breakers are in a degraded condition and also exhibiting high levels of PCBs. These will also be replaced to maintain the reliability of supply. Additionally, all associated and obsolete protection and control systems are to be replaced to minimize the risk of unplanned equipment outages.	2	5	36	2024
Port Hope TS	Based on field reports, transformers T3 and T4 are in degraded condition, are leaking oil and have tap-changer issues. This investment consists of replacing existing units in order to prevent equipment failure and maintain reliability to Hydro One Distribution customers.	2	0	0	2024
Longueil TS	The transformers at Longueil TS are at EOL and in degraded condition. This investment will replace the following; T3 and T4 transformers, and associated protection and control equipment. This investment will maintain reliability of supply to Hydro One Distribution customers and decrease risk of equipment failure	2	0	0	2024
Clarke TS	T3 and T4 supply London Hydro with approximately 60 MW and are to be replaced in order to maintain equipment and long term reliability of supply. These units are in a degraded condition and at EOL. Three low voltages circuit breakers are also in a degraded condition and are to be replaced to minimize the risk of customer interruptions. All the associated obsolete protection and control facilities are also to be replaced together with the identified equipment.	2	0	0	2025
Preston TS	Preston TS is a major load centre for Cambridge area serving ~90MW of customer load. Preston TS transformers T3 and T4 are operating beyond ESL and are in poor condition. The station has 6 Programmable Auxiliary Logic Controller (“PALC”) relays that have been identified with a high failure rate in the HONI system. By 2025, the solid-state relays would have been in-service for ~35 years. It also contains first vintage of microprocessor relays due for replacement. Not proceeding with this work could increase the risk of equipment failure resulting in higher delivery point interruptions. The replacement of these EOL protections is required to maintain the reliability of supply to Energy+ Inc.	2	0	31	2025

Station Name	Scope and Impact	Transformers Replaced	Breakers Replaced	Protections Replaced	In Service Year
Birmingham TS	This investment will address the following EOL equipment; transformer T1, non-arc proof metalclad medium voltage switchgear comprising of six buses and nineteen breakers, poor performing line and ground switches, associated protection and control, AC and DC station service, and two station service transformers. Replacing the equipment identified will maintain supply reliability to Alectra Utilities and an embedded customer Air Liquide. In addition, replacing the equipment identified will decrease the risk of equipment failure and address the safety risk posed by existing medium voltage switchgear.	1	21	28	2025
Newton TS	Based on demographic, condition, environmental hazards, equipment loading and economic data, transformers T1 and T2 are to be replaced under this investment to ensure supply reliability to Alectra Utilities is maintained.	2	0	4	2025
Palermo TS	The following equipment at Palermo TS is obsolete, at EOL, and in degraded condition requiring replacement; transformers T3 and T4, medium voltage oil circuit breakers, and ancillary equipment including the station service transformer and transfer scheme. Replacing the equipment identified above in a single integrated investment will maintain supply reliability to Burlington Hydro, Oakville Hydro and Hydro One Distribution customers, and decrease risk of equipment failure.	2	11	0	2025
Gage TS	Transformers T8 and T9 have been identified for replacement based on preliminary assessment data. The replacement of T8 and T9 transformers will ensure reliability of supply to customer Alectra Utilities.	2	0	8	2025
Bermondsey TS	This investment will result in the replacement of the EOL T3 and T4 Transformers and other EOL station assets and infrastructure including low voltage circuit breakers. Failure of these assets would adversely impact the reliability of supply to Toronto Hydro customers. This investment will result in improved overall station reliability and eliminating operational risks associated with operating EOL equipment, and will preserve reliability to the load customers in the GTA.	2	7	0	2025

Station Name	Scope and Impact	Transformers Replaced	Breakers Replaced	Protections Replaced	In Service Year
Leslie TS	Preliminary assessments have identified T1 230-28-14kV step-down transformer at Leslie TS for replacement with a standard unit. The transformer has two secondary windings supplying 27.6kV and 13.8KV. Toronto Hydro has stated that they plan on decommissioning the 13.8KV bus at this station within the next five years and T1 should only be replaced after this occurs. In addition, a select number of circuit breakers and a significant number of protections require replacement to address end-of-life condition and obsolescence. Coordination with Toronto Hydro is required for this project as they are the owner of the majority of feeder breakers and feeder protections at this station. These replacements will decrease the risk of equipment failure and contribute to maintaining supply reliability to local area Toronto Hydro and Alectra Utilities customers.	1	8	48	2025
Wilson TS	Preliminary assessments have identified T1, and T2 for replacement at Wilson TS, an urban station located in Oshawa, due to declining condition. In addition, select switchgear and a significant number of protections require replacement to address EOL condition and obsolescence. These replacements will decrease the risk of equipment failure and contribute to maintaining supply reliability to local area Oshawa PUC and Hydro One Distribution customers.	2	13	40	2025
Charles TS	Preliminary assessments have identified T3 and T4 for replacement at Charles TS, a space-constrained urban station located in downtown Toronto, due to declining condition. As well, Toronto Hydro may request that T3 and T4 transformers be replaced with larger units to accommodate future loading and operating considerations. In addition four low voltage circuit breakers and a significant number of protections require replacement to address EOL condition and obsolescence. These replacements will decrease the risk of equipment failure and contribute to maintaining supply reliability to Toronto Hydro customers.	2	4	31	2025
Duplex TS	This investment will result in the replacement of the end-of-life T1, T2, T3 and T4 step-down transformers that have been displaying condition issues and other EOL station assets and infrastructure including spill containments, disconnect switches and protection equipment. Failure of these assets would adversely impact the reliability of supply to Toronto Hydro ("THESL") customers in the City of Toronto. In addition, THESL may request these transformers to be replaced with larger standard units in order to meet future supply demand. This investment will replace EOL equipment, eliminate PCB contaminated equipment in the station in order to comply with environmental regulations and will preserve reliability to customers in the GTA.	4	0	12	2025

Station Name	Scope and Impact	Transformers Replaced	Breakers Replaced	Protections Replaced	In Service Year
Woodbridge TS	This investment will result in replacement of the deteriorated, end-of-life T5 transformer that has been displaying condition issues. In addition, other station assets and infrastructures including spill containments, surge arresters and neutralizing transformers require replacement to address end-of-life condition and obsolescence. This investment will decrease the risk of equipment failure and contribute to maintaining supply reliability to Alectra Utilities and Hydro One Distribution customers in the north GTA.	1	0	0	2025
Bathurst TS	This investment will result in the replacement of the end-of-life T3 step-down transformer that has been displaying condition issues. In addition, a select number of circuit breakers and other station components such as surge arresters require replacement to address end-of-life condition and obsolescence. Failure of these assets would adversely impact the reliability of supply to Toronto Hydro customers in the City of Toronto. Coordination with Toronto Hydro is required for this project as they are the owner of feeder breakers and feeder protections at this station. This investment will decrease the risk of equipment failure and contribute to maintaining supply reliability to Toronto Hydro customers.	1	7	0	2025
Strachan TS	This investment will replace the EOL T13 & T14 transformers and associated end-of-life station assets and infrastructure including surge arrestors, and protection equipment. Failure of these assets would adversely impact the reliability of supply to Toronto Hydro customers.	2	0	8	2025
Wallace TS	The following equipment at Wallace TS is at EOL, in degraded condition and requires replacement; T3 and T4 power transformers, oil circuit breakers, and associated protection and control equipment. Replacing them will maintain reliability of supply to Hydro One Distribution customers in eastern Ontario and decrease the risk of equipment failure.	2	3	1	2025
Bilberry Creek TS	This investment is driven by the need to replace T1 and T2 transformers which they are at their EOL. Associated Surge arresters and protections also will be replaced under this investment.	2	0	3	2025
Russell TS	This investment is driven by the need to replace T2 transformer which it is at EOL. Associated Surge arrester and protections also will be replaced under this investment.	1	6	0	2025

Station Name	Scope and Impact	Transformers Replaced	Breakers Replaced	Protections Replaced	In Service Year
Elliot Lake TS	This investment is driven by the need to replace a number of assets that are near EOL at Elliot Lake TS. The main assets driving this investment are power transformers T1 and T2, a medium voltage circuit breaker and associated protections. The option to eliminate one of the three transformers will be evaluated during the estimating stage of the investment. This investment will maintain the reliability of supply to Hydro One Distribution customers in the Elliot Lake area.	2	2	10	2025
Fairchild TS	A preliminary assessment has identified the T1 transformer at Fairchild TS for eventual replacement as unit condition is beginning to decline. In addition, a select number of circuit breakers and a significant number of protections require replacement as they are at end-of-life or obsolete. Coordination with Toronto Hydro is required for this project as they are the owner of the majority of feeder breakers and feeder protections at this station. These replacements will decrease the risk of equipment failure and contribute to maintaining supply reliability to local area Toronto Hydro and Alectra Utilities customers.	1	6	34	2026

SR-06 Load Station Switchgear and Ancillary Equipment Replacement Projects

Start Date:	Q3 2017	**Priority:**	Medium
In-Service Date:	Q2 2026	**3 Year Test Period Cost ($M):**	97.5
Trigger(s):	System Renewal		
Outcomes:	Ensure compliance, system reliability, customer satisfaction, operational efficiencies and reduce maintenance costs		

A. OVERVIEW

Load Supply Station Switchgear and Ancillary Equipment Replacement Projects (the "Projects") are primarily switchgear replacement projects that involve the replacement of load supply station circuit breakers, which include circuit breakers operating between a nominal voltage of 12 kV and 44 kV and can be oil, vacuum, metalclad, Gas Insulated Switchgear ("GIS") or Sulfur Hexafluoride ("SF6") type, that are at the end of their life and whose condition has been rated as high or very high risk in accordance with the asset risk assessment. The Project might also involve the replacement of ancillary equipment (e.g. AC and DC station service equipment, disconnect switches, instrument transformers, etc.) where needed. Prior to replacement, Hydro One will perform the asset risk assessment to ensure that these assets are also at the end of their life and their condition and other factors warrant the replacement.

Load supply stations step down power flow from higher voltages to lower voltages to facilitate the distribution of power via the downstream distribution network. The main Hydro One customers at the load supply stations are LDCs and large industrial customers. The LDCs that are served by Hydro One's transmission system serve most of Ontario's residential, commercial, institutional and small industrial end-users. The end-user facilities that are indirectly affected by the reliability and performance of Hydro One's transmission system include such critical infrastructure as telecommunications systems, water and wastewater treatment facilities, hospitals and other health care facilities, airports and transportation systems, schools and universities, and financial services systems. In light of the foregoing, it is apparent that there is a heightened need to ensure that this critical asset of load supply stations is in good condition and performs reliably.

The Project pacing has been influenced by the assessment of equipment condition and in consideration of operational effectiveness, customer preferences, and safety concerns. Based on Hydro One's load supply station breaker demographic profile, it is forecasted an increasing number of units will age beyond expected service life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Project.

Hydro One has evaluated various alternatives for the Project, as described below, and concluded that replacing the deteriorated load supply station breakers is the most cost effective and efficient undertaking. The projected costs of the Project are estimated to be $97.5 million over the 2020-2022 test period.

B. NEEDS AND OUTCOME

Investment Need

Hydro One's asset strategy is to proactively inspect and monitor the breaker fleet. This allows Hydro One to manage maintenance needs and assess the breaker's associated risk to determine the need for asset replacement. Assessments to repair or replace breakers are done on an individual basis. The assessment is based on risks identified from demographics, condition, environmental factors, utilization, performance, obsolescence, costs comparison between refurbishment and replacement, and other lifecycle considerations.

Hydro One's transmission system includes 293 stations. Hydro One has established a recurring 7-10 year assessment cycle that enables all necessary renewal work to be performed at each of the 293 transmission stations during the cycle. The goal of each asset assessment is to ensure that the assets are not deteriorated, there are no risks that may compromise the reliability of the system, and they do not pose any safety or and/or environmental risk. All assets at a given station are assessed at the same time with a particular focus to transformers, breakers, and protection & control systems – as these are the most critical assets in the system and have a direct impact on a customer. If the assessment identifies multiple key station assets (i.e. transformers, breakers, protection and control equipment) whose risk warrants a replacement, Hydro One then pursues an integrated approach. The asset replacements are bundled into a single integrated station-centric investment project with the main components being identified as the driver for the project. This integrated approach is further described in SR-02**.** In the case where only the breakers are identified as the main asset for replacement along with a small subset of other minor station assets, the station is identified as a candidate for a breaker-focused replacement project.

As of December 2018, Hydro One has 3,205 load supply station breakers in service. Currently, 9% of Hydro One load supply station breaker population is beyond their ESL. Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions. Assuming no replacement, Hydro One anticipates that 568 units (18% of the load supply station breaker population) will exceed their ESL by 2024, and 994 units (31% of the population) will exceed their ESL by 2029.

Asset condition is one of several drivers for breaker replacement. Breaker condition is monitored through information gathered during preventative inspection and maintenance activities. Hydro One performs routine maintenance and replaces breakers that are obsolete, pose safety risks, operate at or above their nameplate rating, have unacceptable performance and have a poor environmental footprint. Poor performance is judged based upon the likelihood of the equipment contributing to load interrupted or unsupplied energy to the customer. Poor environmental footprint is judged based on Polychlorinated Biphenyl ("PCB") levels in excess of legislated requirements. The following issues are examples that have been observed by Hydro One as part of its breaker risk assessment that warrants the replacement of the breakers that are the subject of the Project:

- As breakers age their O-rings and gaskets slowly degrade, thereby causing leaks. The leaks will result in a lower pressure and a path for moisture ingress. This condition over time can result in lower dielectric strength in the breaker and potential for internal flashover which could result in an explosive failure of the breaker.
- Some of the Hydro One fleet of breakers are no longer supported by vendors and aftermarket parts are no longer available or are costly to acquire or fabricate. This is a significant risk factor to some first generation SF6 circuit breakers and certain types of oil circuit breakers. Strategic sparing of breakers is done through replacements where parts are difficult to procure such that removal can help sustain the remaining in service fleet.

The assessment of the load supply station breaker fleet, as of December 2018, shows that 10% of the load supply station breakers are rated at a high or very high risk, as illustrated in Figure 1.

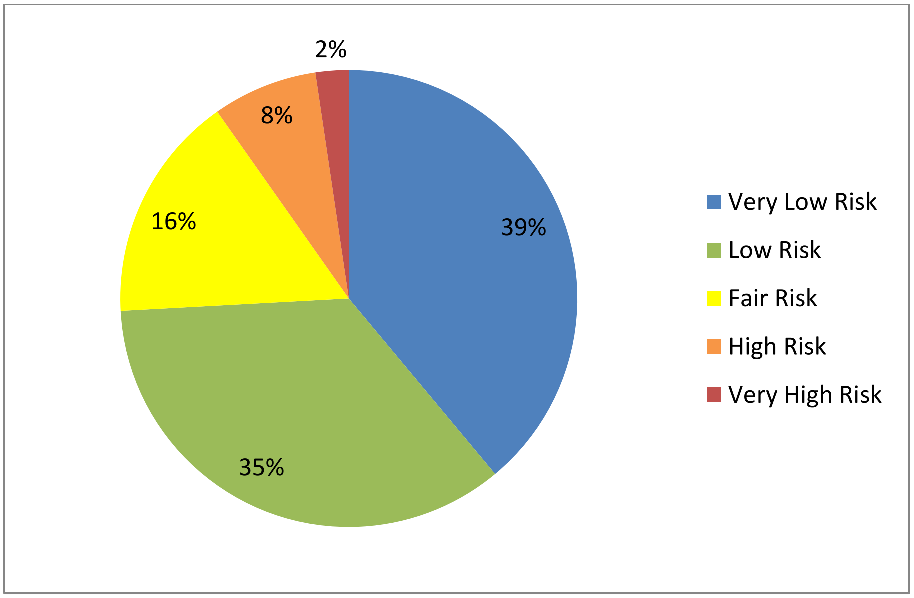

Figure 1 - Summary of Risk Assessment for Load Supply Station Circuit Breakers

Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. When unexpected failure occurs, it could partially or entirely interrupt power flow to load customers as well as constrain embedded generation on the distribution network connected to the load supply station. For the majority of load supply stations, load is considered "stranded" (load that cannot be transferred to an alternate supply without some sort of emergency bypass work, for example, the connection of a mobile substation unit.). Unexpected failures at these stations would result in interruptions to customer delivery points with significant durations. Failures can be catastrophic or the asset could be failing to do what it is intended to do (e.g. breakers can fail to operate/open when needed, i.e. as it is intended to, or they can have insulation failure leading to internal arcing during operation, causing irreparable damage, i.e. catastrophic failure). Furthermore, what complicates the situation is when a certain type of breaker approaches the end of its ESL, vendors often communicate their transition to a limited support and complete obsolescence of aged product lines. As such, it is important to stay on top of this wave of assets approaching

ESL in order to avoid situations where it may become difficult to obtain parts to sustain breakers that vendors no longer support.

Breaker equipment performance is measured by assessing the duration and frequency of forced outages related to the breaker. A “forced outage” is the automatic or forced manual removal of a breaker caused directly by it or its auxiliary equipment.

Furthermore, the PCB Regulations, which came into effect in 2008, and for which amendments came into force on January 1, 2015, implemented deadlines on equipment already in use and in storage, in order to accelerate the elimination of PCBs from the Canadian environment. The PCB Regulations require all oil-filled equipment to contain PCBs less than 50 parts per million (ppm) by December 31, 2025. These requirements impact breaker oil filled bushings and the oil in the main breaker tank. It is estimated that approximately 528 breakers require PCB mitigation, which entails replacing or retro-filling the bushing (i.e., putting in new PCB free oil to bring the PCB ppm value lower). To date, Hydro One has sampled 779 breakers, with another 168 breakers being projected to contain high PCB content once sampled. This projection is based on the rate at which Hydro One has been finding high PCB concentrations in the equipment sampled to date. Using a repair vs. replace analysis, circuit breaker failures that are repairable may be considered for replacement under this program since if there is confirmed PCB content greater than the 45ppm Hydro One set limit, additional costs for the PCB mitigation will also be taken into consideration in addition to the required corrective repairs as a result of the failure.

Breaker failure could partially or entirely constrain generation resources and would lessen the reliability of supply to load customers. If left unattended, Hydro One load supply station breaker fleet will continue to degrade and the fleet demographic with breakers that are in poor or very poor condition will continue to increase, thereby resulting in more frequent and unexpected failures.

Figure 2 below shows the forecast of Hydro One load supply breaker fleet with breakers reaching their ESL.

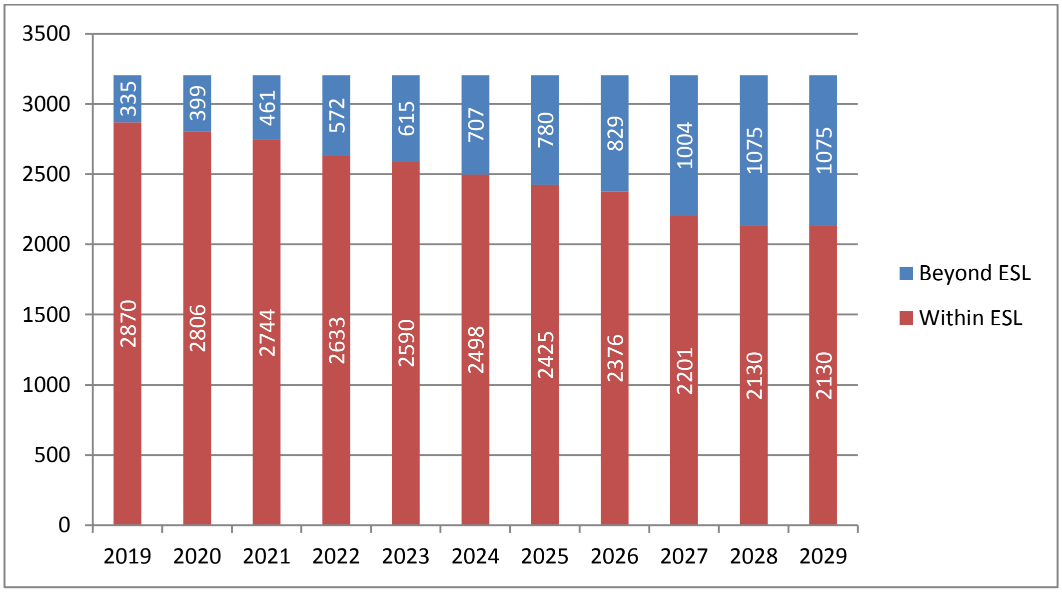

Figure 2: Load Supply Station Class Circuit Breaker Demographic Forecast – without replacement

Breaker failures can severely impact system stability, other connected equipment and employee and public safety. Consequently, it is important to ensure that the current carrying components are in good shape, the mechanical and control systems are operating within specification and that the insulating medium has not been compromised.

Investment Description

The Project is classified as primarily a breaker replacement project. This investment will result in the replacement of switchgear and ancillary equipment at load supply stations that are in a deteriorated, high risk condition where the likelihood of a failure is high. The Project involves a series of individual projects which vary in scope and in size. The Project targets a like-for-like replacement of deteriorated load supply station breakers at various load supply stations. It also addresses the replacements of select ancillary equipment such as switches, batteries, chargers as well as may additionally address site or property issues, customer issues, safety concerns, environmental compliance, and operational issues whose condition might also warrant the replacement.

Hydro One's plan for the breaker fleet replacement over the next five years has been influenced by fleet demographics, observed condition, anticipated condition, and performance factors as well as environmental concerns, as described above. Cumulatively, the Project targets the replacement of 223 breakers over the five year period at 20 stations. Further details pertaining to the Project are provided in Appendix "A" below.

Outcome

As a result of the Project, Hydro One will reduce operational risks (e.g. bottled generation, reduced transfer capability, restricted power flows) associated with the operation of EOL equipment; ensure compliance with North American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating Council ("NPCC") requirements as well as PCB Regulations; maintain long-term reliability of import/export capacity on select transmission interties; and mitigate the risk of constraining generation resources.

The following table presents anticipated benefits as a result of the Project in accordance with the OEB's Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• Maintain reliable performance of load supply to customers through the replacement of EOL equipment.
Operational Effectiveness	• Improve the operational effectiveness of load supply stations through standardization of new equipment.
Public Policy Responsiveness	• Comply with applicable regulatory and environmental requirements.
Financial Performance	• Realize cost savings by addressing multiple deteriorated assets within the station as part of the same project.

C. EXPENDITURE PLAN

As discussed above, the Project is needed to replace the load supply station breakers and ancillary equipment failure of which may compromise the reliability of supply due to the assets being deteriorated and at EOL. Hydro One planned the Project in a way that strives to complete it as effectively and efficiently as possible so to minimize the cost of performing this sustainment task.

Table 1 summarizes historical and projected spending on the aggregate project level. Since the Project consists of a multiple projects, as presented in Appendix “A”, Table 1 below consolidates all the costs for individual projects and presents the total Project costs. The “Previous Years” costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year. Likewise, the costs noted in “Forecast 2025+” are project costs forecast beyond 2024.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	33.0	19.5	32.9	48.9	60.2	79.4	33.8	307.6
Less Removals	0.8	0.2	2.1	1.5	1.8	2.4	1.0	9.9
Gross Investment Cost	**32.1**	**19.2**	**30.8**	**47.5**	**58.4**	**77.0**	**32.7**	**297.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**32.1**	**19.2**	**30.8**	**47.5**	**58.4**	**77.0**	**32.7**	**297.7**

[1] *Includes overhead at current rates.*

Table 2 below presents projected costs on an individual project basis. It also provides a total costs for each individual project along with the proposed in-service date.

Table 2 - Detailed Project Costs

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
Leaside TS	9.1	0.4	0.0	0.0	0.0	9.5	35.7	2020
SACE Breakers	4.1	0.6	0.0	0.0	0.0	4.7	8.4	2021
Finch TS	0.5	2.3	15.3	6.0	0.0	24.2	24.4	2023
Rexdale TS	2.4	10.5	6.1	3.5	0.0	22.5	23.7	2023
Bridgman TS	0.7	4.7	4.8	1.2	0.0	11.4	11.9	2023
Kirkland Lake TS	1.0	6.9	4.0	0.5	0.0	12.4	12.7	2023
Campbell TS	0.5	0.8	4.2	7.0	3.1	15.6	16.0	2024
Norfolk TS	0.2	0.7	1.9	8.3	3.1	14.3	14.3	2024
Bunting TS	0.5	0.8	4.4	8.2	2.7	16.5	16.5	2024
Owen Sound TS	0.0	0.5	0.6	2.8	5.3	9.2	11.1	2025
Dundas TS	0.0	0.2	0.6	1.2	7.7	9.7	12.8	2025
Lake TS	0.0	0.2	0.7	1.7	7.3	9.9	12.8	2025
Burlington TS	0.0	0.4	0.5	1.8	8.0	10.8	13.9	2025
Mohawk TS	0.0	0.2	0.7	1.5	6.7	9.1	11.7	2025
Vansickle TS	0.0	0.2	0.7	1.7	7.3	9.9	12.8	2025
Cherrywood TS	0.0	0.2	0.6	1.1	7.0	8.9	11.8	2025
Port Arthur TS #1	0.1	0.5	1.4	9.6	9.5	21.1	23.6	2025
Muskoka TS	0.0	0.3	0.6	1.4	3.5	5.7	7.0	2025
Pleasant TS	0.0	0.1	0.5	0.9	5.8	7.3	16.8	2026
Net Investment Cost	**19.2**	**30.8**	**47.5**	**58.4**	**77.0**	**232.9**	**297.7**	

Furthermore, the following factors also affect the capital expenditures required for the Project:

- Applicability of Ministry of the Environment, Conservation, and Parks, NERC and/or NPCC requirements;
    - PCB compliance regulations established by Environment Canada drive the cost analysis of whether to retro-fill (refill) oil equipment or replace the PCB affected equipment. The Operations, Maintenance and Administration cost to retro-fill the main tank on a circuit breaker is not deemed prudent for units approaching or beyond their ESL given the increased likelihood of failure.

The preference is to proceed with a capital replacement due to the reduced rate impact and future benefit and reliability a new unit would provide.

- Complexity of project staging and outages required to facilitate work:
  - Increase planning costs portion of the project
  - Increases overall duration of project (interest and overhead costs increases).

- Whether like-for-like replacements are installed in a new location or installed in-situ which may require complex contingency planning:
  - New location will require additional facilities to be installed to connect the equipment rather than re-using existing facilities (i.e. bus work and supporting structures/foundations), increases cost
  - Contingency planning can increase cost by requiring bypass installations, temporary supplies and etc.

- Site conditions and challenges:
  - Urban areas will have constraints with outage planning, construction staging and contingency planning which could add to project duration and complexity and result in higher costs (e.g. working in space-constrained stations; work within neighborhoods where streets are congested and working hours may be constrained due to noise requirements; unique design and construction challenges; outage constraints as service still needs to be maintained amidst the required work)

Remote rural areas will increase costs due to difficulty of working on difficult terrain, difficulty accessing the station with heavy equipment, delivery of large equipment and etc.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: Reactive Component Replacement involves waiting for deteriorated breakers or ancillary equipment to fail and replace components on a reactive basis. Hydro One has rejected this alternative for the following reasons:

- Assets in deteriorated condition will continue to deteriorate and decline, thereby increasing the likelihood of unexpected failures. These failures might be prolonged and might result in extended equipment and customer outages which will subsequently lower System Average Interruption Duration Index and System Average Interruption Frequency Index performance.
- An increased likelihood of unexpected failures would lead to increased environmental risk due to the possibility of a release into the environment during a failure event.
- An increased likelihood of unexpected failures would lead to increased safety risk due to the possibility of a failure event being catastrophic in nature.
- There is expectation that there will be more catastrophic failures and systemic failures which based on past experience, cost more to replace compared to planned replacements due to the amount of damage, number of equipment affected and duration of outages related to these events.
- The maintenance frequency would likely increase and result in increased maintenance costs. As assets age beyond their ESL, repairs become more costly as the assets are no longer supported by vendors and aftermarket parts are no longer available or are costly to acquire or fabricate.
- Replacing reactively would lead to assets being replaced in an uncoordinated fashion. This would lead to assets only being replaced on an in-situ basis and

reduce the ability to prudently address other station infrastructure. Uncoordinated fashion here is referring to planning the work in a holistic approach.

- Many of the assets at a station are interconnected and replacing a single asset can either limit Hydro One in the design options for this replacement or cause the need for rework in the future, for example, coordinating protection replacements with breaker replacements
- When multiple assets are reaching EOL, there is opportunity to make changes to the electric configuration to make improvements to the reliability and performance of the bulk electricity system. Uncoordinated fashion can also pertain to the mobilization of construction forces, the staging of work to minimize impact to customers (outage frequency and duration).

Alternative 2: Station Refurbishment involves the refurbishment of the entire station where significant populations of assets are in a high risk condition, before failure occurs. This alternative is only a viable solution where the other key station assets, such as transformers and switching facilities are in a deteriorated, high risk condition. This alternative has been considered for the Project and has been rejected as there is insufficient justification to proceed with a complete station refurbishment. Hydro One does not replace the transmission assets unless the asset condition warrants the replacement. Where majority of assets are EOL, this alternative may then be considered, but then the project would fall under the SR-02.

Alternative 3: Like-for-Like Planned Replacement is a preferred undertaking. It involves proactively replacing individual station components in a single integrated investment, with switchgear and ancillary equipment that are in a deteriorated, high risk condition. This alternative is recommended as it addresses the needs identified at the station to maintain the reliability of Hydro One's transmission system in the most cost effective manner, consistent with the findings of the customer engagement process. This alternative focuses on the replacement of select equipment in a like-for-like manner, unless otherwise requested to meet broader system needs.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of load supply station breaker replacement projects are: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges, or regulatory approvals. A thorough risk assessment workshop is performed during the initial project planning phase where all known risks are identified and mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize to a minimum the loss of supply to the customer. The plan might include the construction of a temporary by-passing circuit or supply of portable generation that will maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. Another example is the involvement of real estate from the project inception. It allows for the early identification of real estate issues, such as missing or inadequate land rights. Once the issue is identified, Hydro One tries to resolve it prior to execution of the project.

1 **APPENDIX A – DETAILED PROJECT PLAN**

Station Name	**Scope and Impact**	**Breakers Repl.**	**Prot. Repl.**	**In Service Year**
Leaside TS 27.6kV	Replace 27.6kV switchgear, switchyard and associated protection & control equipment at Leaside TS which is a space-constrained urban station located in mid-town Toronto. In addition, replace the main AC station service equipment, upgrade the station perimeter security system, and upgrade sections of the station drainage system. These replacements will decrease the risk of equipment failure and contribute to maintaining supply reliability to midtown Toronto Hydro customers.	14	20	2020
SACE Breakers – Woodroffe TS / Russell TS	This investment will replace select SACE type metalclad breakers used for capacitor bank switching. These breakers have been a concern for several years. The interrupter contacts have been found to be excessively worn causing the metalclad breaker to fail explosively, resulting in significant damage. This problem is compounded by the difficulty in checking the contacts and the excessive number of switching operations. There are four remaining breakers to be replaced; two at Woodroffe TS and two at Russell TS. The capacitor protections for three of these units are end of life and their replacement has been integrated into this investment	4	3	2021
Finch TS	This investment includes the replacement of the majority of protection and control equipment and a significant subset of breakers at Finch TS that are at EOL due declining condition and obsolescence. In addition other minor EOL assets and infrastructure will be replaced. These replacements will decrease the risk of equipment failure and contribute to maintaining supply reliability to Toronto Hydro customers.	14	49	2023
Rexdale TS	Rexdale TS is a step-down transformer station located in in the western area of Toronto, Ontario. The Rexdale 27.6kV switchyard consists of four bus-connected capacitor banks and twelve M-class feeders that supply the surrounding area. The primary transmission-connected customer served by the station feeders is Toronto Hydro. This investment includes the replacement of existing 27.6kV metalclad switchgear assets with indoor Medium Voltage Gas-Insulated Switchgear (MVGIS) equipment as well as a significant number of protections due to their end-of-life condition and obsolescence. The existing breaker type is not suited for capacitive switching and failures have been experienced in the past. The existing breakers are also obsolete and retro-fit options are not available for this 27.6kV voltage class; therefore, the reliability of the station would be enhanced with the removal and replacement of these obsolete circuit breakers. Also, with the installation of modern protective relays maintenance intervals will be extended therefore resulting in a reduction in maintenance costs. New protective relays are equipped with self-monitoring capabilities which allows for remote oversight of the relay health. This investment will decrease the risk of equipment failure and contribute to maintaining supply reliability to Toronto Hydro customers.	22	37	2023

Station Name	Scope and Impact	Breakers Repl.	Prot. Repl.	In Service Year
Bridgman TS	This investment replaces Hydro One’s switchgear that is part of Toronto Hydro’s end-of-life High Level A1/A2 switchgear lineup. These replacements will be done in coordination with Toronto Hydro’s High Level A1/A2 switchgear replacement project. Due to potential space and feeder egress limitations at Toronto Hydro’s High Level MTS facility, there is the possibility that refurbishment of the large heritage building at Bridgman TS may be required to provide space for the installation of the new A1/A2 switchgear lineup. These end-of-life switchgear replacements will decrease the risk of equipment failure and contribute to maintaining supply reliability to midtown Toronto Hydro customers.	6	0	2023
Kirkland Lake TS	The main assets driving this investment are 115kV PTs, 44kV circuit breakers and protections that have reached EOL. This investment will maintain the reliability of supply to Hydro One Distribution customers in the Kirkland Lake area.	5	9	2023
Campbell TS	Campbell TS is a major load centre for the Guelph area serving ~150MW of customer load with future load growth to ~160MW. Campbell TS has three 13.8kV metalclad lineup, of which, metalclad #2 is in poor condition and also has growing concerns for obsolescence. In addition, the station has 17 Programmable Auxiliary Logic Controller (“PALC”) relays that have been identified with having a high failure rate in the HONI system. It also contains first vintage of microprocessor relays due for replacement. Remaining electro-mechanical relays would have been in-service for over 50 years by 2022. Not proceeding with this work could increase the risk of equipment failure resulting in higher delivery point interruptions. The replacement of this EOL equipment is required to maintain the reliability of supply to Guelph Hydro Electric Systems.	12	32	2024
Norfolk TS	The following equipment at Norfolk TS is at EOL, obsolete and requires replacement; medium voltage oil circuit breakers, associated protection and control, AC station service transfer scheme, and two station service transformers. Replacing the equipment identified above in a single integrated investment will maintain supply reliability to Hydro One Distribution customers in the Simcoe area and decrease the risk of equipment failure.	13	27	2024
Bunting TS	Preliminary assessments indicate that the following equipment has reached EOL and will require replacement; partially arc proof metalclad medium voltage switchgear, associated protection and control including station battery, and the AC distribution scheme. Replacing this equipment in a single integrated investment will maintain supply reliability to Alectra Utilities in St. Catharines and decrease the risk of equipment failure.	17	33	2024
Owen Sound TS	The main assets driving this investment are 44kV circuit breakers and protections that have reached end of life. This investment will maintain reliability of supply to Hydro One Distribution customers in the Owen Sound area.	12	14	2025

Station Name	Scope and Impact	Breakers Repl.	Prot. Repl.	In Service Year
Dundas TS	The non-standard BY switchyard at Dundas TS is a legacy Hydro One structure that presents breaker and insulator replacement challenges due to space limitations that impact worker safety. The average service life of the low voltage breakers are approximately 50 years and the replacement of the BY switchyard is required to ensure reliability of supply to Alectra Utilities can be maintained. This investment will also result in the replacement of end of life protection and control equipment and station service transformer SS1.	13	10	2025
Lake TS	This investment is driven by the need to replace non-arc-proof metalclad switchgear that presents health and safety risks to employees and obsolescence issues pertaining to replacement of breakers in the event of failure. This investment will result in the replacement of the J1J2 and Q1Q2 metalclad switchgear and station service transformers SS1 and SS2.	17	0	2025
Burlington TS	The non-standard BY switchyard at Burlington TS is a legacy Hydro One structure that presents breaker and insulator replacement challenges due to space limitations that impact worker safety. The average service life of the low voltage breakers are approximately 55 years and the replacement of the BY switchyard is required to ensure that the reliability of supply to Burlington Hydro can be maintained. This investment will also result in the replacement of end of life protection and control equipment, station service transformer SS15 and capacitor bank SC4.	9	34	2025
Mohawk TS	This investment is driven by the need to replace non-arc-proof metalclad switchgear that presents health and safety risks to employees and along with obsolescence issues pertaining to replacement of breakers in the event of failure. This investment will result in the replacement of the B1B2 metalclad switchgear and associated protection and control equipment.	9	9	2025
Vansickle TS	This investment is driven by the need to replace non-arc-proof metalclad switchgear that presents health and safety risks to employees and along with obsolescence issues pertaining to replacement of breakers in the event of failure. This investment will result in the replacement of the BY metalclad switchgear and associated protection and control equipment.	9	13	2025
Cherrywood TS	Replace 44kV outdoor switchyard breakers, disconnect switches and associated protection & control equipment at Cherrywood DESN yard which they are at their EOL. The main assets driving this investment are 44kV oil circuit breakers. This investment will maintain reliability of supply to Toronto Hydro (Cavanagh MTS).	13	20	2025
Port Arthur TS #1	The main assets driving this investment is the 25kV DESN yard which poses significant health and safety risks to Hydro One personnel due to inadequate electrical clearances. This investment will maintain the reliability of supply to Thunder Bay Hydro and Hydro One Distribution customers in the Thunder Bay area.	17	67	2025

Station Name	Scope and Impact	Breakers Repl.	Prot. Repl.	In Service Year
Muksoka TS	This investment is driven by the need to replace a number of assets that are near EOL at Muskoka TS. The main assets driving this investment are 44kV oil circuit breakers. This investment will maintain reliability of supply to Hydro One Distribution customers in the Muskoka area.	8	0	2025
Pleasant TS	Pleasant TS is a transformer station located in the GTA (Brampton, Ontario) which primarily supplies Alectra Utilities. This investment includes the replacement of EOL oil-filled circuit breakers as well as a significant number of protections which require replacement due to condition and obsolescence. With the installation of modern protective relays, maintenance intervals will be extended reducing maintenance costs.	9	26	2026

SR-07 Protection and Automation Replacement Project

Start Date:	Q4 2016	**Priority:**	Medium
In-Service Date:	Q2 2026	**3-year Test Period Cost ($M):**	28.0
Trigger(s):	Strategic, System Renewal		
Outcomes:	Ensure compliance, system reliability, customer satisfaction, operational efficiencies and reduce maintenance costs		

A. OVERVIEW

The Protection and Automation Replacement Project (the "Project") is primarily a project that involves the replacement of protection and automation systems that have reached their End of Life ("EOL"). The Project might also involve the replacement of auxiliary equipment (e.g. instrument transformers, disconnect switches, AC and DC systems etc.) where needed. Prior to replacement, Hydro One will visually inspect and where applicable test the condition to ensure that these assets are, also, at the end of their life and their condition warrants the replacement. The Project targets the replacement of protection and automation systems at bulk transmission stations and load supply transmission stations.

The bulk transmission system provides the "backbone" of Ontario's electricity system. Bulk power flows through the 500kV, 230kV, and 115kV transmission systems. The protection system is a critical element of the transmission system that detects abnormal system conditions. Upon detecting an abnormal condition, the protection systems immediately trigger the necessary station equipment to operate to isolate faulted components. Automation assets are highly complex electronic systems and devices which integrate substation and switchyard devices. These systems enable the monitoring and control of power system assets and facilities at all times to achieve safe, reliable and efficient operation of the Ontario transmission grid. As a licensed transmitter operating transmission facilities greater than 100 kV, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards adopted by North

American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating Council ("NPCC"). Hydro One transmission customers include large electricity generators, large industrial end-users and the majority of Ontario's Local Distribution Companies ("LDCs"), all of whom are directly affected by the reliability and performance of Hydro One's transmission system.

Load supply stations step down power from higher voltages to lower voltages to facilitate the distribution of power via the downstream distribution network. The main Hydro One customers at the load supply stations are LDCs including Hydro One distribution system. The LDCs and Hydro One distribution system that are served by Hydro One's transmission system serve most of Ontario's residential, commercial, institutional and small industrial end-users. The end-user facilities that are indirectly affected by the reliability and performance of Hydro One's transmission system include such critical infrastructure such as telecommunications systems, water and wastewater treatment facilities, hospitals and other health care facilities, airports and transportation systems, schools and universities, financial services systems, etc.

In light of the foregoing, it is apparent that the protection and automation systems are critical assets of the transmission system and there is a heightened need to ensure that these systems are in a good condition and perform reliably.

The Project pacing has been influenced by the assessment of equipment condition where Hydro One assessed the likelihood of the protection and automation systems to cause a delivery point interruption or a major reliability risk, thereby, impacting the bulk electric system. Because it is not easy to monitor the condition of all protection and automation systems, expected service life ("ESL") is being used as flag for assessment while other factors, such as safety, regulatory compliance, grid reliability, technology obsolescence and innovation, have been used to identify high risk assets that form part of the Project.

Hydro One has evaluated various alternatives for the Project, as described below, and concluded that replacing those protection and automation systems that are at EOL is the most cost effective and efficient undertaking. The projected costs of the Project are estimated to be $28.0 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

As discussed in TSP Section 2.2.1.3 and 2.2.1.4, Hydro One has a thorough and ongoing asset management process that involves monitoring and reviewing transmission assets and assessing their condition. Hydro One’s protection and automation asset strategy is to proactively inspect and monitor the protection and automation systems, track their failure rate, misoperations and manufacturers’ support. This allows Hydro One to manage maintenance needs and assess the protection and automation systems’ condition as a factor to determine the need for asset replacement. Assessments to repair or replace protection and automation systems are done on an individual basis. The assessment is based on risks identified from demographics, condition, safety, technology obsolescence, innovation, utilization, and costs comparison between refurbishment and replacement. Units in poor condition, known manufacturer defects/obsolesce, or anticipated higher repair costs are prioritized for replacement.

Hydro One’s transmission system includes 293 stations. Hydro One has established a recurring seven- to ten-year assessment cycle that enables all necessary renewal work to be performed at each of the 293 transmission stations during the cycle. The goal of each asset assessment is to ensure that the assets are not deteriorated, there are no risks that may compromise the reliability of the system, and they do not pose any safety or and/or environmental risks. All assets at a given station are assessed at the same time with a particular focus to transformers, breakers, and protection and automation systems – as these are the most critical assets in the system and have a direct impact on a customer. If the assessment identifies multiple key station assets (i.e. transformers, breakers, and protection and automation equipment) whose condition warrants a replacement, Hydro One then pursues an integrated approach. The asset replacements are bundled into a single integrated station-centric investment project with the main components being identified as the drivers for the project. This integrated approach is further described in Investment Summary Document SR-02. In the case where only one asset, e.g. protection system or automation system identified as the main asset for replacement along with some auxiliary equipment, the station is identified as a candidate for a protection and automation systems replacement project.

Protection Systems

Hydro One's protection systems are comprised of instrument transformers, relays, sensors and communication devices. The protection system is a critical element of the transmission system that detects abnormal system conditions. Upon detecting an abnormal condition, the protection systems immediately operate the necessary station equipment to isolate faulted components. A faulted element could cause a cascading effect and result in a major system disruption involving service interruptions, equipment damage and employee and public safety issues.

Protection system equipment is activated only when there is a fault or other power system problem. A fault or system disturbance can result in equipment damage, personnel exposure to hazards, wide area disturbances and prolonged customer outages. Protection system misoperations provide an overall indication of the protection system's health. It is the most important indication of the protection system performance. Hydro One tracks the performance of the protection system by analyzing every protection system operation to determine if it operated as expected. Protection system components also capture detailed records for post event analysis. This information assists in determining the root cause of power system events and facilitates in the mitigation or elimination of the issue.

Hydro One currently has 12,506 protection systems in-service. Approximately 27% of the protection system population is operating beyond its ESL. Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions. Assuming no replacement, Hydro One anticipates that 5,184 units (41% of the protection system population) will exceed their ESL by 2024, and 6,952 units (56% of the population) will exceed their ESL by 2029. Table 1 below presents a summary of the ESL of Hydro One's protection systems broken by technology type. Once the protection system reaches its ESL, the risk of failure is significantly elevated**.** There is no way to predict time of failure with certainty as most of the systems and their components do not show signs of wear and fatigue. They usually operate until they suffer an abrupt failure.

Table 1 - Summary of the ESL of Hydro One's Protection Systems by Technology

Protection Type	**Quantity**	**Avg Age (Years)**	**ESL (Years)**	**% Beyond ESL (if no protections are replaced)***					
				2018		**2024**		**2029**	
				Count	**% of Type**	**Count**	**% of Type**	**Count**	**% of Type**
Solid State	2,026	35.3	25	1,835	91%	1906	94%	1941	96%
Electro-mechanical	3611	38.8	45	1,322	37%	2,038	56%	2,279	63%
Microprocessor	6,869	8.7	20	206	3%	1,240	18%	2,732	40%
TOTAL	**12,506**	**27.6**		**3,363**	**27%**	**5,184**	**41%**	**6952**	**56%**

** Data as of Dec 2018 and does not include protections planned to be replaced in 2019*

On average, 94% of station protection and 89% of line protection misoperations are related to hardware failures associated with protection systems.

Programmable Auxiliary Logic Controller ("PALC") relays are a type of solid state protection system. They have shown an increase in recorded defects and trouble calls over the years due to deteriorating components within the relay. As a result, and due to the inability to obtain replacement units, PALC relays are considered high risk assets. As such, Hydro One has been actively replacing PALC relays since 2014 and, to date, it has replaced approximately 250 PALC relays. Figure 1 demonstrates that once the deteriorated equipment is taken out of service, the number of annual defects and subsequent outages is reduced. Currently, Hydro One has approximately 300 PALC relays in operation and plans to replace them over the next five years.

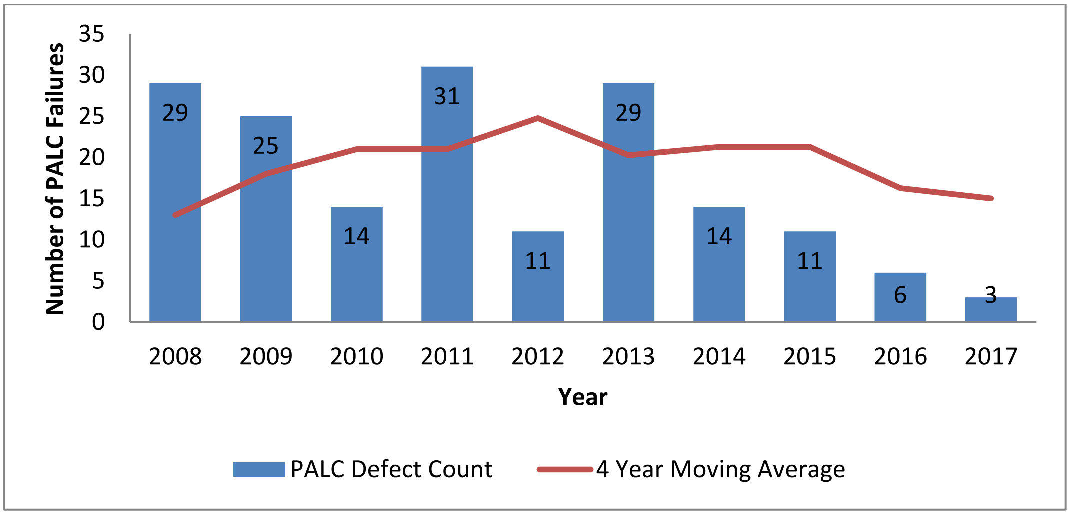

Figure 1 - Number of PALC Relay Defects

Furthermore, vendor support is critical. For example, as could be seen in Table 1 above, over 90% of the solid-state fleet of protection system is operating beyond their ESL. Because this equipment is obsolete, Hydro One has little or no support from its vendors when it comes to service, replacement units or provision of spare parts. When a device operates beyond its ESL, the risk of failures is elevated. It even further elevates when there is no vendor support, including supply of spare parts and/or firmware and engineering support. This might impact restoration time of the outage, caused by faulty, obsolete protection system, as the repair time will be longer. The repair might include the installation of a new device based on different technology which will require further reengineering and construction work.

As a licensed transmitter operating transmission facilities greater than 100 kV, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards adopted by NERC and NPCC. With respect to protection systems, Hydro One is required to comply with *NPCC Regional Reliability Reference Directory # 4 - Bulk Power System Protection Criteria* (the “Directory”). The Directory sets out the minimum protection system design criteria and review process for protection systems for the Bulk Power System. It requires entities such as Hydro One to include level of redundancy in the design. As part of the compliance verification, for any construction work in a station that is part of Bulk Power System, Hydro One is required to prepare and deliver Facility Presentation to NPCC’s Task Force for System Protection (TFSP). By reviewing Facility Presentation package, TFSP reviews and approves the project scope and its design concept. Currently, most of Hydro One bulk stations comply with most of the requirements of the Directory. However, in older stations which were built before the requirements came into effect, there are often areas that require investments in order to fully comply with this standard. Even though the older installations are “grandfathered” against the Directory requirements, when upgrade work is planned for certain equipment in the station, the requirement is that other related systems are upgraded progressively to bring station into full compliance over time. An example for this is: when a transformer replacement is done, the expectation is for the project to result in the related equipment meeting the standard e.g. control cables, relays, DC auxiliary supply. This may trigger installation of new cable trenches and replacement of cables, and go as far as including the replacement of the related protection relays in the project scope. Among other objectives described in this section, the Project is targeting these investments to ensure that the protection systems are compliant with the Directory.

<u>Automation Systems</u>

Automation assets are highly complex electronic systems that enable the monitoring and control of power system assets and facilities at all times to achieve safe, reliable and efficient operation of the Ontario transmission grid. They also enable timely responses to emerging problems, real-time condition assessments, expedited restoration activities, and work planning.

Automation systems provide several critical capabilities such as:

- Local and remote real-time monitoring, control and troubleshooting facilities for Hydro One field staff, control center staff and the Independent Electricity System Operator ("IESO") in accordance with Market Rules;
- Critical transmission station automation and integration functions to support the operations of all power system equipment;
- Collection, processing, and archival of non-operational data for post-event analysis and to support the asset management decision-making processes;
- Enabling cyber security functionalities such as system event monitoring, authentication, authorization, logging and accounting;
- Supporting the fulfillment of regulatory obligations; and,
- Interfaces with external utilities, generation, and customers.

Hydro One automation system assets consist of legacy and modern technological vintages. Legacy automation components primarily consist of Remote Terminal Units ("RTU"). This equipment is based on the concept of physical wiring and the digital conversion of electrical signals delivered by wires, generally for a single function/application. These systems utilize slow communication connections and employ a variety of protocols. Modern automation equipment is network enabled to utilize high-speed communications and has a smaller physical form-factor, exponentially increased computational capabilities, and greater ability for integration with the Network Management System ("NMS") as compared to its legacy counterparts. Information is conveyed through standard protocols which shift previous manual labour work related to hard wiring, towards skilled programming capability.

There are over 18,000 components and devices in service to support automation functionalities of Hydro One's Power System Monitoring & Control ("PSMC"). 46% of the automation system population is of the modern vintage type, while 54% is of the legacy vintage type. The ESL for automation systems, outlined in Table 2 below, is classified according to their vintage and is based on generally accepted industry practices and Hydro One experience.

Table 2 - Automation System Expected Service Life

Automation Vintage	Expected Service Life
Legacy (copper-based)	20 years
Modern (IP-based)	15 years

Automation system condition is an important indicator of equipment reliability. Internal components degrade as a function of time, which can alter the performance of the automation equipment. The potential risks to system and customer reliability as a result of this long term demographic pressure needs to be managed through consistent capital replacement programs. Legacy automation systems experience defects four times more often than modern control systems within the same timeframe. Furthermore, 54% of automation equipment is of the legacy vintage and makes up about 79% of the total defect occurrences and associated maintenance costs. This is expected to trend upward as the legacy equipment reaches its expected service life. Table 3 presents the number of defect reports for modern and legacy automation equipment over the last 11 years.

Table 3 - Summary of Defect Reports Broken Down by Year

Year	LEGACY			MODERN			
	RTU	**PSR**	**Transducer**	**LMC/LCC**	**Gateway**	**Router**	**Switches**
2008	325	23	19	11	18	4	2
2009	550	68	21	27	25	5	0
2010	635	42	36	19	18	10	1
2011	674	69	29	52	12	4	2
2012	555	39	20	43	34	20	9
2013	577	48	14	71	30	17	10
2014	431	39	29	67	38	19	19
2015	384	39	31	78	56	16	18
2016	478	44	16	195	63	24	20
2017	912	8	3	208	63	31	43
2018	465	14	6	136	98	21	82
Total	**5986**	**433**	**224**	**907**	**455**	**171**	**206**

Hydro One has been tracking the reliability of automation equipment with the objective of determining future work programs. The following are the key objectives that Hydro One focuses to determine the level of investment needed for its automation system fleet.

- Evaluation of modern industry offerings and migration towards cost-effective alternatives. The legacy technology and design has been in service for over thirty years. Risks and costs are mounting as more of these systems reach or exceed ESL. As Hydro One modernizes its automation fleet though the deployment of station Local Area Networks ("LAN"), there is no longer a need for expensive legacy RTU installations. Modern solutions have a small form factor, are a fraction of the cost, and are IP-based with flexible scalability to match our needs. Hydro One is pursuing options to modernize the system by working with vendors and other utilities through EPRI and NATF to establish and implement modern solutions with the intent to replace legacy systems.
- Optimization of existing designs to reduce capital and Operations Maintenance and Administration ("OM&A") expenditures. Hydro One evaluates changes in controls design architecture to maximize device functionalities. Many existing deployments were designed with legacy technologies that provided certain

capacities or redundancies to meet reliability requirements. As some legacy technologies are discontinued and replaced with modern industry offerings, reliability targets and mandated requirements will be met with reduced or no redundancy required.

In comparison to protection, the automation world has seen significant advancements over the past decade. Hydro One is undertaking these opportunities to further modernize and bring improvements to operational efficiency, a reduction in operational risks, reliability, and cost containment. The following are examples of modernization being implemented as part of the Project:

i. Removal of end of life Local Controller Computers and implementation of the same functionality into Station Gateways;
ii. Deployment of direct Supervisory Control and Data Acquisition to allow stations to communicate directly with the OGCC so as to phase out hub sites; and
iii. Substitution of multiple Local Maintenance Computers at a station with a single transient cyber asset which complies with the NERC Critical Infrastructure Program standards.

Investment Description

The Project is classified as primarily protection and automation systems replacement project. The Project is targeting protection and automation systems that have reached their EOL. These systems do not offer the functionalities of modern relays, such as monitoring and diagnostic capabilities, and have a high likelihood of failure. Protection system failure can result in unexpectedly removing power system elements from service or failing to operate when required to isolate faulted equipment which directly impacts power flow through the bulk electricity system. Hydro One is also targeting for replacement; populations of equipment which are showing increasing failure, rates have limited manufacturer support or can no longer reliably perform their intended function due to equipment technological advances.

Through the investment planning process documented in TSP Section 2.1, needs assessments are conducted on station assets to identify and coordinate candidate investments. These investments will replace protection systems and auxiliary equipment in high risk condition where the likelihood of failure is high and, in doing so, standardize them and bring them into compliance with applicable requirements. The investment level has been determined based on the assessment of asset condition and performance. In addition, this investment provided further consideration of customer preferences, safety concerns, and compliance requirements.

The Project involves a series of individual projects. Each bulk station and load supply station protection and automation replacement project will vary in size and scope. The investment will address: associated protection, control and telecom systems, ancillary station equipment in deteriorated condition, site or property issues, customer issues, safety concerns, environmental compliance, and operational issues whose condition might also warrant the replacement. Further details pertaining to the Project as well as individual investment for bulk station and load supply stations can be found in Appendix "A".

Outcome

As a result of the Project, Hydro One will reduce operational risks (e.g. bottled generation, reduced transfer capability, restricted power flows) associated with the operation of EOL and deteriorated equipment; ensure compliance with NERC and NPCC requirements; enhance protection and automation functionality where technological advances can help reduce outage duration (fault location algorithms) and prevent protection misoperations (e.g. second harmonic restraint); maintain long-term bulk power flow reliability throughout the power system and mitigate the risk of constraining generation resources.

The following table presents anticipated benefits as a result of the Project in accordance with the OEB's Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• Maintain reliability performance of bulk electricity system power flows through the replacement of EOL protection systems.
Operational Effectiveness	• Improve operational flexibility of the bulk electricity system through the implementation of modern protection and automation systems, enabling enhanced telemetry, control, and operational capabilities
Public Policy Responsiveness	• Comply with applicable regulatory requirements
Financial Performance	• Realize cost savings by addressing multiple degrading components within the station as part of the same project.

C. EXPENDITURE PLAN

As discussed above, the Project is needed to replace the protection and automation systems at bulk power stations and load supply stations which may compromise the reliability of supply due to the high risk assets that have reached their EOL. Hydro One planned the Project in a way that strives to complete it as effectively and efficiently as possible so to minimize the cost of performing this sustainment task.

Table 4 summarizes historical and projected spending on the aggregate project level. Since the Project consists of a multiple projects, as presented in Appendix "A", Table 4 below consolidates all the costs for individual projects and presents the total Project costs. The "Previous Years" costs are the direct project costs for projects noted above that have incurred costs prior to 2020. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024.

Table 4 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	2.5	7.0	8.8	13.1	12.6	22.3	15.5	81.8
Less Removals	0.1	0.2	0.3	0.4	0.4	0.7	0.5	2.4
Gross Investment Cost	**2.4**	**6.7**	**8.6**	**12.7**	**12.2**	**21.7**	**15.0**	**79.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**2.4**	**6.7**	**8.6**	**12.7**	**12.2**	**21.7**	**15.0**	**79.3**

[1] *Includes overhead at current rates.*

Table 5 presents projected costs on an individual project basis. It also provides a total costs for each individual project along with the proposed in-service date.

Table 5 - Detailed Project Costs

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
Tillsonburg TS	3.8	2.4	0.2	0.0	0.0	6.3	7.0	2021
Frontenac TS	2.0	3.0	0.8	0.0	0.0	5.7	7.3	2022
Hunta SS	0.5	1.4	4.3	1.6	0.0	7.7	8.0	2023
Halton TS	0.5	0.8	5.5	2.6	0.2	9.6	9.6	2024
Minden TS	0.0	0.2	0.5	0.8	3.6	5.1	6.5	2025
Erindale TS	0.0	0.7	0.9	5.6	6.8	13.9	15.9	2025
Bramalea TS	0.0	0.2	0.6	1.6	11.0	13.4	25.0	2026
Net Investment Cost	**6.7**	**8.6**	**12.7**	**12.2**	**21.7**	**61.9**	**79.3**	

The following factors also affect the capital expenditures required for the Project.

- Applicability of NERC and/or NPCC requirements

  - Replacement of protection and automation systems must comply with applicable NERC/NPCC which has significant increase on costs. When protection/control equipment is replaced, if applicable in to the given elements in the station, the systems must be designed to meet the application NERC and/or NPCC requirements (for example redundancy or protection systems, AC and DC supply, physical and diverse separation of equipment).
- Need for additional civil infrastructure such as cable trenching, and/or ducts
  - This could include physical separation of A & B communication paths which have significant increase on costs. This requirement is mandated by the applicable NPCC design criteria.
- Available space within the control building o relay room to facilitate upgrades
  - New location will require additional facilities to be installed to connect the equipment rather than re-using existing facilities (i.e. relay room rack space), increases cost. The lack of space could or additional cabling in cable pans could trigger a new relay building.
- Complexity of stages and outages required to facilitate work
  - Increases planning costs portion of the project, and
  - Increases overall duration of project (interest and overhead costs increases)

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: Reactive Component Replacement involves waiting for deteriorated and end-of-service life protection and automation systems to fail and replace components on a reactive basis. This alternative is more costly not only for Hydro One but also for impacted customers. Hydro One has rejected this alternative for the following reasons.

- Assets in deteriorated condition will continue to deteriorate and decline, thereby increasing the likelihood of unexpected failures. These failures might be prolonged and might result in extended equipment and customer outages which will subsequently lower System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") performance.

- An increased likelihood of unexpected failures would lead to increased environmental risk due to the possibility of a release into the environment during a failure event.
- An increased likelihood of unexpected failures would lead to increased safety risk due to the possibility of a failure event being catastrophic in nature.
- Since these replacements would likely be executed on an emergency basis, it would constantly result in the reprioritization of planned work and inefficient redeployment of resources.
- This alternative limits the ability to account for future requirements and has a high risk of re-work and future costs.
- This strategy is likely to increase operating and maintenance costs, decrease equipment performance and might impact the safety of personnel on site.

Alternative 2: Planned Component Replacement is the preferred investment option. It involves proactive replacement of end of life protection systems and associated ancillary equipment that are in a high risk condition, before failures occur. Hydro One's replacement strategy for protection systems is focused on replacing systems that have a high likelihood of causing delivery point interruption and impacting the reliability of bulk electricity system. Because it is not easy to monitor the condition of all protection systems, ESL and other factors are used as a trigger to identify high risk assets which undergo further condition assessment to identify replacement candidates. Other factors driving protection system replacements are summarized below.

- Safety – Protection system failure to operate can potentially expose workers and the public to the risk of electrocution which ultimately can result in significant injuries or even death. Proactive replacements are required to mitigate this risk.

- Regulatory Compliance – Hydro One's protection system must comply with all applicable NERC and NPCC standards. Protection system upgrades are often needed in order to comply with new or updated standard requirements.
- Functional Requirements - the requirements for protection system functionality may change due to power system changes (e.g, system stability requirements) or changes to other components of integrated protection and automation system which lead to incompatibility of the existing protection hardware with the associated devices.
- Technology Obsolescence – Many protection system components are no longer available, limiting the availability of spare parts and support; which can adversely impact outage planning and overall system reliability. This is a significant factor for electromechanical and solid state systems as they are no longer supported by relay vendors which are focusing their efforts on microprocessor based relays.
- Innovation – New microprocessor based protection systems have advanced monitoring and diagnostic capabilities which can provide insight into station equipment performance and early detection of problems, potentially avoiding equipment damage. This alternative is recommended as it addresses the needs identified at the transmission station to maintain reliability for Hydro One's bulk transmission system in the most cost effective manner.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of bulk station breaker replacement projects are: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges, or regulatory approvals. A thorough risk assessment workshop is performed during the initial project planning phase where all known risks are identified and mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize the probability of loss of supply to the customer. The plan might include switching a customer to an alternative supply, the construction of a temporary by-passing circuit or supply of portable generation that will maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. While protection and automation replacement projects are rarely real estate dependent, in some cases there is a need to involve real estate from the project inception. This allows for the early identification of real estate issues, such as missing or inadequate land rights. Once the issue is identified, Hydro One tries to resolve it prior to execution of the project.

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APPENDIX A – DETAILED PROJECT PLAN

Station Name	Scope and Impacts	Number of Protections	In Service Year
Tillsonburg TS	The majority of the protection and control equipment at Tillsonburg TS are end of life due to obsolescence and pose a high risk to reliability. This investment will address these EOL protections and control and maintain supply reliability to the Tillsonburg area.	30	2021
Frontenac TS	Frontenac TS – DESN is a major load centre for the Kingston Area serving ~100MW of customer load. It contains Electro-mechanical relays that would have been in-service for over 45 years by 2022. It also contains first vintage of microprocessor relays due for replacement. Due to space limitation within the existing building, A new PCT building (PCT-box design) will be installed along with the new protections. Not proceeding with this work could increase the risk of equipment failure resulting in higher delivery point interruptions. The replacement of these EOL protections is required to maintain the reliability of supply Kingston Hydro.	51	2022
Hunta SS	This investment will address EOL protections that are negatively impacting the reliability of the transmission system. This investment will maintain reliability in the 115kV transmission network and supply to customers north of Timmins.	13	2023
Halton TS	Halton TS is a step-down transformer station that supplies Milton Hydro and Halton Hills Hydro customers via twelve 27.6kV feeders. This investment will replace end-of-life PALC relays that have been identified with high rates of failure. By installing modern protective relays, maintenance intervals will be extended and maintenance costs will be reduced. Station reliability will be enhanced with the removal and replacement of these obsolete devices.	31	2024
Minden TS	This investment will primarily address end-of-life protection, control, and telecommunication equipment. Furthermore, the main DC station service transfer scheme is end-of-life; its condition and performance is declining and there are obsolescence and vendor support risks. This investment will maintain the reliability of the bulk electric system.	20	2025
Erindale TS	This investment will address end-of-life PALC relays that have been identified with high rates of failure. It will also address AC & DC station service systems, and six circuit breakers that have declining condition and performance.	31	2025

Station Name	Scope and Impacts	Number of Protections	In Service Year
Bramalea TS	This investment will address end-of-life protection and control equipment. It will also address eight circuit breakers, six switches, and DC station service that have declining condition and performance.	78	2026

SR-08 John Transformer Station Reinvestment

Start Date:	Q3 2018	**Priority:**	High
In-Service Date:	Q4 2024	**3-year Test Period Cost ($M):**	44.0
Trigger(s):	System Renewal, Reliability		
Outcomes	Improve reliability, maintain safe and reliable transmission system, ensure compliance with regulatory requirements, realize cost savings		

A. OVERVIEW

The John Transformer Station Reinvestment (the "Project") involves the refurbishment of John Transformer Station ("TS") due to the end of life assets, supply limitations, short circuit levels that limit transfer capability as well as clearance issues that pose a safety concern for maintenance personnel and limit the work that can be completed.

John TS is the most heavily loaded transformer station in the Central Toronto 115kV network and is critical to the supply of power to downtown Toronto. The station was built in the 1950s with facilities added in the 1960s and 1970s. Many components in the station have reached or are approaching their expected service life.

Hydro One has reviewed various alternatives for the John TS reinvestment, as described below and concluded that a staged reinvestment and replacement of the station facilities is the most cost effective option. The projected cost of the Project is estimated to be $44.0 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

John TS, located in downtown Toronto is a major source of supply to the City's core and comprises the following facilities:

- A 115kV switchyard consisting of ten 115kV breakers. The 115kV switchyard contains eight breakers that are oil type and are about 42 years old.
- Two 45/75 MVA, 115/13.8kV kV Transformers T1/T4. The transformers are 50 years and 48 years old respectively.
- Two 45/75 MVA, 115/13.8kV kV Transformers T2//T3. The transformers are 42 and 33 years old respectively.
- Two 75/125 MVA, 115/13.8kV kV Transformers T5/T6. The transformers are 42 and 41 years old respectively.
- An outdoor 13.8kV switchyard that interconnects transformers T1/T2/T3 and T4 to the Toronto Hydro low voltage metalclad switchgear. The 13.8kV outdoor switchyard is about 50 years old with obsolete equipment.
- 13.8kV low voltage metalclad switchgear. This switchgear is mostly owned by Toronto Hydro with the exception of transformer secondary and bus tie breakers that are owned by Hydro One. This switchgear ranges in age from 33- 50 years old.

As mentioned above most of the equipment is between 40-50 years old. The oil breakers in the 115kV switchyard have limited manufacturer support and parts availability. The switchyard insulators are almost entirely cap and pin type that are prone to failure with age. There is a need to reinvest in the switchyard and replace the aging and deteriorated assets.

Four of the transformers have been identified for replacement due to their condition. Two transformers T1 and T4 are being monitored for rapid degradation and need to be replaced on a priority basis.

The 13.8kV low voltage outdoor switchyard is very congested with limited electrical clearances and non-standard design. The existing clearances at the station pose a safety concern for maintenance personnel and limit the work that can be completed. Many of the buses, switches, cables, insulators and duplex reactors are end of life or obsolete and need to be replaced or removed as they are limiting capacity and are in poor condition.

Lastly, transformer secondary breakers that are part of the Toronto Hydro non-arc proof switchgear need to be separated from the Toronto Hydro line-up and replaced by Hydro One. These breakers have been identified as posing health and safety concerns and require additional precautions in order to perform maintenance. Such precautions include large outage zones for maintenance work which are difficult to achieve. Hydro One work will be coordinated with Toronto Hydro switchgear replacement plans to ensure that supply to area customers is maintained while the refurbishment work is under way.

Toronto Hydro is currently in the process of building a new load supply station, Copeland MTS. One of the objectives of this station was to have the ability to supply a portion of John TS's load in order to enable outages at John TS to facilitate maintenance or capital work. Once Toronto Hydro's Copeland MTS is completed, Hydro One will have the ability to transfer partial load from John TS and this will allow for a staged replacement of assets within the station to meet current and future needs. This investment is dependent upon Toronto Hydro maintaining its current schedule for in-servicing Copeland MTS.

Investment Description

The Project involves a staged replacement of assets of John TS on the existing property. This will include replacement of the existing transformers, removal of the 13.8kV outdoor low voltage switchyard and installation of transformer secondary 13.8kV low voltage breakers in the first stage. The first stage will also include replacement of the associated transformer protections and the AC and DC station service equipment.

Toronto Hydro have advised that their new replacement metalclad switchgear will be rated at 72MVA compared to the 48MVA rating of the present switchgear to meet future requirements and have requested that the existing 45/75MVA transformers be replaced with larger size 60/100MVA units.

The second stage will consist of replacement of the 115kV breakers, the upgrade of the 115kV switchyard and replacement of existing switchyard protections

Outcome

The Project will result in the following:

- Improve the long-term reliability of supply to downtown Toronto and increase the security of a critical station;
- Reduce operational risks associated with end-of-life equipment; and
- Ensure compliance with MOECP requirements.

The following table presents anticipated benefits as a result of the Project in accordance with the OEB's Renewed Regulatory Framework:

Customer Focus	• Improve reliability to customers by minimizing outages due to poor performing, obsolete and end-of-life equipment
Operational Effectiveness	• Maintain a safe and reliable transmission system by addressing end-of-life, obsolete equipment, and incorporating safety by design in an integrated manner.
Public Policy Responsiveness	• Ensure compliance with Ministry of Environment and Climate Change requirements by upgrading site drainage, spill containment, and noise abatement.
Financial Performance	• Realize cost savings by replacing multiple end of service life components within the station in a staged manner.

C. EXPENDITURE PLAN

Table 1 below presents forecasted costs for the Project. The project costs were developed using a Hydro One planner's estimate. The "Previous Years" costs are the direct project costs incurred prior to the 2020 test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	0.4	3.6	18.4	26.3	24.7	21.5	16.1	111.1
Less Removals	0.1	0.1	0.6	0.7	0.6	0.6	0.5	3.2
Gross Investment Cost	**0.3**	**3.5**	**17.9**	**25.6**	**24.0**	**20.9**	**15.6**	**107.8**
Less Capital Contributions	0.0	0.0	0.0	3.0	3.0	0.0	0.0	6.1
Net Investment Cost	**0.3**	**3.5**	**17.9**	**22.6**	**21.0**	**20.9**	**15.6**	**101.8**

[1] *Includes Overhead at current rates.*

The expenditures in 2021, 2022 and 2023 are associated with replacement of the transformers T2, T3, T5 and T6 and the replacement of the 13.8kV and 115kV switchyard. The following factors might further affect the costs of the Project:

- Final station design and configuration due to the complexity of the station's configuration and coordination required with Toronto Hydro; and
- The complexity of project staging and outages required to facilitate work.

D. ALTERNATIVES

Three alternatives were considered for the refurbishment of John TS as follows:

Alternative 1: In-situ Replacement of All Station Equipment involves the replacement of assets at the existing station site. This option would plan for a like-for-like replacement of the station asset except for the 115kV switchyard where consideration is being given to using GIS equipment to replace the existing switchyard

Alternative 2: Station Relocation involves a complete rebuild and relocation of John TS to another property in downtown Toronto. This alternative was rejected as impractical because of the difficulty in finding an appropriate site for the new station. Even if a new site were to be available, it would be extremely difficult and costly to relocate the 115kV high voltage underground lines and the 13.8kV underground distribution feeders to the new site.

Alternative 3: Staged Partial or Entire Station Rebuild By Expanding to the Adjacent Property. A third option considers utilizing an existing adjacent parking lot to facilitate the refurbishment of John TS. This alternative while feasible and simplifying the construction, expands the John TS footprint and would be significantly more expensive than an in-situ replacement. It was therefore not considered further.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the Project are: the availability of Copeland MTS to supply portions of John TS during construction, the availability of outages, resource constraints, construction execution difficulties, customer coordination, equipment procurement challenges, or regulatory approvals. A thorough risk assessment is performed during project planning where all known risks and mitigating actions are identified. For example, to address outage constraints, Hydro One develops an outage coordination plan. This operation plan aims to eliminate or minimize the loss of supply to the customer. The plan might include the construction of a temporary by-pass circuit or connecting portable generation to maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages.

SR-09 Transmission Station Demand, Spares and Targeted Assets

Start Date:	Q1 2020	**Priority:**	High
In-Service Date:	Ongoing Program	**3 Year Test Period Cost ($M):**	117.6
Trigger(s):	Compliance, Strategic, Customer Satisfaction, Corrective Maintenance, Reliability and Environment		
Outcomes:	Compliance with ORTAC and TSC; improve customer satisfaction by carrying out replacements in a timely manner to minimize unplanned customer interruptions; maintain transmission system reliability, safety, and/or power quality; reduce safety risks associated with failing equipment		

A. OVERVIEW

Transmission Station Demand and Spares (the “Program”) is a reactive program that is primarily designed to prevent, immediately respond to, or minimize the effects of an emergency situation. The Program involves the procurement of spare transmission station equipment such as transformer operating spares, circuit breakers, instrument transformer, disconnect switches, insulators, power cables, surge arrestors, capacitor banks, reactors, protection, and control and telecom equipment. The Program covers the resources required for emergency replacement of transformers or other minor station equipment that have failed or shown signs of deterioration while in-service and near term deteriorated asset replacements that do not align with station centric projects. It also includes the necessary design, construction and commissioning resources to replace failed station equipment in a timely manner.

Failed or deficient station equipment may cause an impact on the transmission system that varies from being minor to significant. It might pose safety or environmental risks as well as impose generation and/or power flow constraints, affecting regional load flow limits and customer operations. As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards administered by the IESO and the Transmission System Code (the “TSC”). The Program ensures that Hydro One continues to comply with its legal obligations while mitigating safety, system reliability and environmental risks that an unforeseen failure might cause.

B. NEED AND OUTCOME

Investment Need

Hydro One operates one of the largest transmission systems in North America. As a critical asset for Ontario, Hydro One's transmission system extends to most of the province, and encompasses diverse geographic and climactic condition. It comprises the Bulk Electric System ("BES"), which is subject to the reliability standards established by the North American Electric Reliability Corporation ("NERC") that ensure the integrity of the interconnected North American BES. Transmission stations are a key category of infrastructure that is critical to the function of Hydro One's transmission system. The major components of transmission stations include power transformers, circuit breakers, disconnect switches, bus work, insulators, power cables, surge arrestors, capacitor banks, reactors, station service, grounding systems, protection and telecom systems, site infrastructure and buildings.

If a transmission station asset fails or is in imminent danger of failure, it is critical for Hydro One to have the ability to perform emergency replacements of that asset as soon as possible, so as to ensure the integrity and reliability of the transmission system. When a transmission station asset fails, the impact varies depending on the location of the component and level of redundancy (if any) built into the station's electrical configuration. In a best case scenario, transfer capability could be reduced even though the customer will not see any interruption. But in the worst case, where there is stranded load without any transfer capability, customers can be interrupted until the component is replaced (or manually bypassed if possible). Other types of failures of transmissions station assets might pose safety or environmental risks.

The Program ensures that Hydro One maintains an adequate inventory of spares for its transmission station assets in order to facilitate the expedient replacement of a failed or deficient component at a transmission station. These assets might include transformers, power equipment, ancillary equipment, protection, control and telecom equipment and other minor equipment.

The reliability framework for Ontario's electricity transmission system is based on the reliability standards established by NERC, which have been adopted and are enforced in Ontario by the IESO. The IESO has established load restoration criteria for high voltage supply to a transmission customer. In accordance with the Section 7.2 of the IESO's *Ontario Resource and Transmission Assessment Criteria* ("ORTAC"), Hydro One is required to restore an affected load within the following restoration times:

- All load must be restored within approximately 8 hours.
- When the amount of load interrupted is greater than 150MW, the amount of load in excess of 150MW must be restored within approximately 4 hours.
- When the amount of load interrupted is greater than 250MW, the amount of load in excess of 250MW must be restored within 30 minutes.

Furthermore, the OEB's *Transmission System Code* ("TSC") sets out, among other things, the minimum requirements that a transmitter must meet in maintaining its transmission system. In accordance with Section 5.4 of the TSC, Hydro One is required to take immediate actions during an emergency or to prevent or minimize the effects of an emergency, ensure public safety or safeguard life, property or the environment, as well as to protect the stability, reliability, or integrity of Hydro One's transmission facilities. As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards imposed by the IESO and the TSC.

In light of the foregoing, to maintain system reliability and prevent load interruption to customers, Hydro One needs to maintain a stock of a spare transmission station equipment (e.g. transformers, circuit breakers, instrument transformer, disconnect switches, insulators, power cables, surge arrestors, capacitor banks, reactors, protection, control and telecom equipment) and the sustained ability to respond immediately to an emergency situation or to prevent or minimize the effects of an emergency.

Investment Description

The Program includes the procurement of spare transmission station equipment such as transformer operating spares, circuit breakers, instrument transformer, disconnect switches, insulators, power cables, surge arrestors, capacitor banks, reactors, protection, control and telecom equipment. The Program also covers the resources required for emergency replacement of transformers or other minor station equipment that have failed while in-service. This includes the necessary design, construction and commissioning resources to replace failed station equipment in a timely manner to ensure compliance with standards imposed by the IESO and the TSC.

According to historical data (see Table 1 below), Hydro One has experienced an annual average of 4 transformer failures or a 0.51% annual failure rate, which is aligned with the industry average as indicated by data from EPRI's Industry Wide Transformer Database for 1995 to 2015.

Table 1 - Transformer Annual Class 1 Failure Rate over Past 10 Years

Year	115kV	230kV	500kV	5 Year Average Annual Failure Rate, All Voltage classes
2008-2012	0.40%	0.37%	1.41%	0.44%
2013-2017	0.56%	0.41%	2.44%	0.59%
10 Year Average Annual Failure Rate	0.48%	0.39%	1.92%	0.51%

As Hydro One's transformer fleet ages, the probability of failure increases requiring resources and funding to be available to respond to these failures.

The bulk of the Program comprises of the spare transformer inventory. Hydro One uses the Markov Model to determine the appropriate number of spare transformers required to ensure continuity of electricity supply to customers, safety and reliability. The Markov Model takes into consideration the probability of failure, carrying costs and procurement lead time to determine the most cost effective number of spares to be kept in inventory. Hydro One retained a third party expert, EPRI, to undertake a study to verify that Hydro One's spare transformer requirements are appropriate and consistent with industry best practices. EPRI developed analytics tools to optimize the power transformer spares practice, which was compared with Hydro One's own Markov modeling. The study,[1] determined that Hydro One's operating spare transformer analysis using the Markov Model is sound. Hydro One continues to take steps to achieve and maintain the required quantity of operating spare transformers to ensure reliability and improve cost efficiency.

The Program is also comprised of activities related to replacing near term deteriorated asset that have yet to fail but warrant replacement in a timely manner. These targeted replacements are planned where there is no integrated station replacement project to address the replacement. This program mainly focuses on smaller equipment i.e. switches, instrument transformers, batteries, station service ancillary etc.

Outcome

The Program aims to maintain reliable supply to customers by replacing failed station equipment in a timely manner and mitigating safety and environmental risks. It will allow Hydro One to replace failed station equipment as promptly as possible to restore the system to normal operating conditions, which will ensure compliance with Hydro One's regulatory obligations.

The following table presents anticipated benefits as a result of the Program in accordance with the OEB's Renewed Regulatory Framework:

Customer Focus	• Improve customer satisfaction by minimizing interruptions and providing timely power restoration to customers. • Reduce risk and severity of customer supply interruptions due to lack of operating spares.
Operational Effectiveness	• Maintain transmission system reliability and safety. • Reduce safety risks associated with failing equipment.

[1] See TSP 1.4 Attachment 5 "Operating Spare Transformers Requirement Assessment".

Public Policy Responsiveness	• Ensure Hydro One meets its compliance obligations with respect to power system restoration and reactive response.

C. EXPENDITURE PLAN

Table 2 below presents forecasted costs for the Program, which are established based on based on comparable historical costs and projected future needs.

Table 2 - Total Investment Cost

($ Millions)[1]	**Prev. Years**	**2020**	**2021**	**2022**	**2023**	**2024**	**Forecast 2025+**	**Total**
Capital[2] and Minor Fixed Assets	0.0	45.4	37.5	38.1	38.8	39.5	0.0	199.2
Less Removals	0.0	1.2	1.1	1.1	1.1	1.2	0.0	5.6
Gross Investment Cost	**0.0**	**44.2**	**36.4**	**37.0**	**37.7**	**38.3**	**0.0**	**193.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**44.2**	**36.4**	**37.0**	**37.7**	**38.3**	**0.0**	**193.6**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown
[2] Includes Overhead at current rates.

Factors driving the costs of this Program are:

- The scope of the replacement work required to address the failure;
- The type, rating and quantity of the assets requiring replacement;
- The historical annual quantity of transformer failures and demand transformer replacements that require spare deployment; and
- The type of transformer requiring spare deployment, as the costs of the operating spare transformers can vary based on transformer specifications such as voltage and capacity.

Controllable costs are being managed and minimized through the standardization of station designs and equipment ratings that result in the reduction of spare inventory for replacement parts, and through the establishment of unit price contracts with vendors.

D. ALTERNATIVES

The Program is non-discretionary and, as such, no alternatives have been considered. Failure to respond to an emergency or to prevent or minimize the effects of an emergency in a timely manner may result in non-compliance with the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC") and/or the TSC. It might also negatively impact customer operations and customer service. For example, the lead time to procure a new transformer can be a year or more which would introduce lengthy replacement timelines and negatively impact system reliability.

E. EXECUTION RISK AND MITIGATION

The risks of potential customer supply interruptions and longer outages caused by a failed transformer must be mitigated by timely response, which will be unplanned and reactive by definition. There are risks to executing such unplanned work including the availability of resources and long lead times for the purchase of new transformers. The risk of resources being unavailable is mitigated by having a process to enable the effective prioritization of resources to support immediate and emergent work as required.

SR-10 Transformer Protection Replacement

Start Date:	Q4 2015	**Priority:**	Medium
In-Service Date:	Q4 2020	**3 Year Test Period Cost ($M):**	3.8
Triggers:	Strategic, Preventative Maintenance/ System Renewal, Reliability, Immediate / Short-Term Compliance		
Outcomes:	Reduced risk or regulatory non-compliance, lower OM&A cost and increased system reliability		

A. OVERVIEW

Transformer Protection Replacement due to Second Harmonic Misoperations (the "Project") involves the replacement of old electromechanical protection systems with modern, microprocessor based relays. The Project was developed to mitigate transformer protection misoperations due to low second harmonic content. The main drivers of the Project is to ensure Hydro One continues to be compliant with the reliability standards established by North American Reliability Corporation ("NERC") and to ensure that Hydro One continues to operate its transmission system in a reliable and efficient manner. Hydro One has evaluated various alternatives for the Project, as described below, and concluded that proactive replacement of identified transformer protection relays with new microprocessor-based protection systems is the most cost effective and efficient undertaking. The projected costs of the Project are estimated to be $3.8 million over the test period.

B. NEED AND OUTCOME

Investment Need

Every transformer, when being energized, initially draws a large amount of current, called inrush current. The inrush current is up to fifteen times larger than the normal current that transformers typically experience. As such, the transformer protection system would normally interpret the inrush current as abnormal, and will result in the transformer being automatically removed from service by protection operation. The inrush currents are rich in harmonics, particular second harmonic. The increased presence of the second harmonic is detected by the relay and identifies that a transformer is being energized for the first time. Once the second harmonic is identified, a relay's tripping function is intentionally blocked for a short period of time to allow transformer current to settle to its steady-state value.

New style transformers which employ low loss core designs as well as some of the older transformers under certain system and design conditions are known to produce insufficient amount of second harmonic current. When an insufficient amount of second harmonic is produced, a protection relay is unable to detect that a transformer is being energized and causes a protection relay to operate incorrectly. This results in misoperations of a protection system. When transformer protections misoperate, Hydro One has to dispatch two crews to the site. One crew inspects the transformer and performs tests (e.g. dissolved gas analysis) to make sure that the fault is not caused by some real, transformer related issue. Another crew collects the necessary data from relays and sends it to engineering staff to analyse the operation and determine what actually caused the relay to operate.

As a licensed transmitter operating transmission facilities of the Bulk Energy System ("BES"), Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards adopted by NERC and Northeast Power Coordinating Council ("NPCC"). NERC Standard PRC-004-3 — *Protection System Misoperation Identification and Correction* (the "PRC-004") establishes the process for monitoring protection system events for BES elements, as well as identifying and correcting the causes of any misoperations caused by protection systems. The PRC-004 standard requires entities, such as Hydro One, to investigate BES system events involving protection operations in order to determine if they were correct operations or misoperations, and report misoperations to NERC. Once a misoperation is confirmed, Hydro One is required to establish and complete a corrective plan within a prescribed period of time that mitigates the identified sources of misoperation.

When a protection system misoperates due to second harmonic issue, Hydro One has to designate the transformer as unavailable until all tests are completed and it is verified that a transformer is safe to go back online. This might negatively impact Hydro One customers as the misoperation decreases system reliability. Hydro One transmission system is designed with a certain level of redundancy. If a backup transformer or other related equipment (protections, breakers etc.) fails, there is a high probability of customer power outages occurring or Hydro One may have to start shedding load (i.e. disconnecting customers) in order to balance the load demand vs. supply capacity and prevent further cascading outages.

Investment Description

The Project was developed to mitigate transformer misoperations due to low second harmonic content and to ensure Hydro One is in compliance with the PRC-004. The Project involves replacing old electromechanical protection systems with modern, microprocessor based relays.

Over the last 15 years, Hydro One has recorded more than 100 transformer protection misoperations related to the low second harmonic in the transformer inrush current. In accordance with the PRC-004, Hydro One developed a solution to mitigate these misoperations. The solution requires the use of protective functions which are available in modern microprocessor based relays, also known as Intelligent Electronic Devices ("IED"). The solution uses a feature known as "second harmonic cross blocking" which is an algorithm that allows the relay to detect energization based on how it detects the second harmonic. This feature is only found in modern microprocessor based relays. Using historical misoperation data as well as the transformer asset registry, Hydro One identified a list of candidate protection systems that utilize old electromechanical relays to be replaced. Hydro One conducted further analysis to identify the station reinvestment projects. As described elsewhere in the evidence, Hydro One utilizes integrated approach to replace major assets of a transformer station (e.g. transformer, breakers, protection and automation systems) where condition of these assets warrants replacement. As such, where it was possible, Hydro One bundled the replacement of the old electromechanical protection system with modern, microprocessor based relays into station reinvestment projects.

The Project targets transformer stations that are not part of a station reinvestment project, however, and contain older vintage relays that need to be replaced to ensure NERC compliance and system reliability. Hydro One plans to replace 15-20 old electromechanical protection systems with modern, microprocessor based relays per year, totalling 80 protection relays since the start of this project in 2016. This pacing prioritizes the sites that experience the largest number of misoperations while mitigating the demand on engineering and construction resources.

Outcome

The Project has been in execution since 2016 and has proved to be successful, to date. It has reduced the number of misoperations significantly. In 2013 there were 7 misoperations, 4 in 2014, 5 in 2015, and only 2 in 2016 and 2017.

Once the Project is fully executed, the risk of protection misoperations due to low second harmonic content will be significantly lowered. This will result in:

- Ensuring compliance with applicable the PRC-004 standard;
- Reduced Operations, Maintenance and Administration ("OM&A") expenditures due to fewer misoperations and related investigations; and
- Increased operational flexibility, as transformer protection misoperations will be reduced, maintaining equipment availability and system reliability;

The following table presents anticipated benefits as a result of the Project in accordance with the OEB's Renewed Regulatory Framework:

Outcome Summary

Customer Focus	• Improve system reliability
Operational Effectiveness	• Improve the ability to respond to system events by increasing availability of critical power systems components
Public Policy Responsiveness	• Ensure compliance with the PRC-004 standard
Financial Performance	• Reduction in OM&A expenditures resulting from reduced dispatches of field staff for protection misoperation as well as reduced need for analysis and tracking of misoperations.

C. EXPENDITURE PLAN

Table 1 below presents forecasted costs of the Project. Costs for the Project are based on budgetary estimates prepared by Hydro One using historical costs of projects of similar scope. These factors determine the complexity of the installation and the amount of alteration required for each station to the new protection system. Controllable costs have been minimized through the standardization of transformer protection design. The "Previous Years" costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	11.9	3.8	0.0	0.0	0.0	0.0	0.0	15.7
Less Removals	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Gross Investment Cost	**11.8**	**3.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**15.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**11.8**	**3.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**15.6**

[1] *Includes Overhead at current rates.*

D. ALTERNATIVE

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: Reactive Maintenance of the Asset involves waiting until the identified protections are replaced by a sustainment capital project as they become candidates for replacement when reaching their Expected Service Life ("ESL"). This alternative was considered and rejected due to the negative impact on potential NERC non-compliance issues and the reliability of Hydro One's system since the relays involved in this project are not planned for replacement as part of integrated station investments within the 2020 to 2024 planning period. Allowing these relays to remain in service would result in prolonged risk of protection misoperation, negatively impacting customer reliability.

Alternative 2: Proactively Replace Affected Protection Relays is a preferred undertaking. It involves proactively replacing identified transformer protection relays with new microprocessor-based protection systems. This alternative utilizes a verified solution and employs microprocessor-based relays which are the current Hydro One standard. This alternative allows Hydro One to significantly reduce potential service interruptions, reduce OM&A expenditures associated with misoperation tracking and analysis, and eliminate risk of non-compliance with NERC standard PRC-004.

E. EXECUTION RISK AND MITIGATION

The Project risks and their mitigation measures are outlined below:

- Equipment Outage Availability – In order to replace protection relay, one of the redundant protection channels must be taken out of service. Often, network operations require that the power system component being protected is taken out of service. There is a risk that, due to operating conditions, Hydro One is not able to obtain outages to perform the work. In order to mitigate this risk, project management stuff was instructed to give enough lead time to outage planners.

- Engineering Resources – There is always a risk that highly specialized engineering and construction personnel needed to execute this type of work are not available at the time of execution. This will be mitigated by coordinating with internal service providers well as well as exploring possibilities to outsource the work to third party provides.

Witness: Donna Jablonsky

SR-11 Legacy SONET System Replacement

Start Date:	Q2 2017	**Priority:**	High
In-Service Date:	Q4 2024	**3 Year Test Period Cost ($M):**	57.7
Trigger(s):	System Renewal		
Outcomes:	Maintain reliability of the transmission system operation and maintenance		

A. OVERVIEW

Legacy SONET Systems Replacement (the "Project") involves the replacement of Hydro One's Synchronous Optical Network ("SONET") system with a new packet-based technology. The SONET system is based on SONET technology which is primarily utilized by Protection and Supervisory Control and Data Acquisition ("SCADA") systems. The SONET system, along with the physical infrastructure (fibre or microwave-based) that establishes communication links, are the cornerstones of Protection and Automation systems which support grid reliability as well as protection of costly station and line assets. Additionally, SONET is used for communicating non-operational data, business data, voice and security information, and is used as backhaul communication for the provincial mobile radio system.

SONET system, which primarily includes multiplexer equipment at transmission stations, is approaching its end of life ("EOL").The determination of approaching EOL in this case is made by the facts listed below:

- Large segments of the system are exceeding expected service life ("ESL"), and
- High risk for grid reliability,
- Technological obsolescence as vendors withdraw support (end of vendor support), and;
- Long lead times for planning and execution of asset replacements due to large installed base.

Witness: Donna Jablonsky

When end of vendor support ("EVS") is reached, spare parts become increasingly harder to find which leads to repairs and maintenance becoming increasingly costly, systems are at risk of longer outages and reliability is degraded. Hydro One's first generation of SONET system (the "Legacy System") equipment has reached its ESL as well as its EVS. It is no longer being developed by vendors.

Other factors influencing the EOL decision are:

- This system is critical for operation of the grid as its failure would have high reliability impact.
- Accelerated rate of failures in the future could require replacement volume that would be impossible to execute due to a very large installed base.

The failures caused by SONET equipment have resulted in multiple power system telecom services being rendered unavailable until repairs were carried out. Loss of communications channels can result in real-time control actions to be taken in order to either constrain power flow on transmission system and/or to remove power system elements from service such as breakers, lines, transformers etc. In turn, this can result in negative impact to the reliability of the transmission system, and potentially expose customers to a less reliable configuration due to the loss of redundancy. To address the reliability issues associated with the obsolescence of the technology and network equipment on which SONET is built, Hydro One has developed the Project, which aims towards replacing the Legacy System with a modern solution. Hydro One has evaluated various alternatives for the Project, as described below, and concluded that proactive replacement of the Legacy System with new packet-based technology is the most cost effective and efficient undertaking. The projected costs of the Project are estimated to be $57.7 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

The SONET communication network is primarily utilized for mission critical protection and SCADA applications. Mission critical protection means communications that are essential for the safe and reliable operation of the transmission system. These are protection trip signals that are initiated by protection systems to isolate high voltage equipment during a fault condition to prevent further or widespread outages. This can include the tripping of circuit breakers at multiple stations by sending a signal from one station to another through the SONET network in order to isolate a fault on a transmission line. Operation of the transmission system requires equipment telemetry and status information being continuously communicated to the Ontario Grid Control Centre ("OGCC") through the SONET network.

Protection trip signals, also known as teleprotection signals, along with other data traffic, are multiplexed, using time-division multiplexing ("TDM"), to higher bandwidth signals by SONET add-drop multiplexers on the network providing reliable and robust communication between Hydro One facilities. The SONET network multiplexer equipment is composed of two vintages; the first generation initially deployed between 1998 and 2007 and the second generation from 2004 on-wards. In addition to the multiplexer equipment, other key components that make up the SONET network include microwave links, optical amplifiers and 48Vdc backup power supplies. The network topology is such that communication rings are created connecting the stations to provide redundant communication links that can stretch up to hundreds of kilometres across the province. There are certain segments of network that are made up of microwave links as opposed to fibre connected paths. Although they were economical at the time of SONET deployment, over time they have created a capacity and bandwidth limitation on a typical ring topology while higher capability equipment from the vendor is not available as they have obsoleted the equipment.

To assess asset condition and determine its EOL, Hydro One takes into account asset age vs. ESL, rate of failures, reliability risk, vendor support, manufacturer recommendations and historical asset retirement. In addition, field deficiency reports, trouble calls and failure incidents provide an indication of the overall condition of the power system telecom assets and play a role in the determination of the EOL.

As one of the reference data, the ESL for most microprocessor based equipment is 15-20 years. Table 1 below shows typical ESL in years for the SONET communication Network.

Table 1 - Summary of SONET Equipment

Telecom System/Asset Class	Asset Type	Quantity	Expected Service Life (Years)	Currently Beyond ESL*	Beyond ESL 2024	Beyond ESL 2029
SONET Communication Network	Multiplexers	263	15	86	197	247
	Digital Radios	35	15	35	35	35
	Optical Amplifiers	32	15	29	31	31
	48 VDC Batteries	281	10-20[1]	23	49	141
	48 VDC Chargers	281	20	87	129	165

** Data as of December, 2018*
[1] Varies based on equipment make and/or model

The first vintage of multiplexer equipment has reached its ESL and is facing technological obsolescence as vendors withdraw support and, as such, spare parts become increasingly harder to find. The majority of SONET equipment failures are associated with the first vintage of multiplexer equipment (Vintage A MUX) as shown in Figure 1 below. These failures have resulted in multiple power system telecom services being rendered unavailable until repairs were carried out. Loss of communications channels can result in the removal of power system equipment from service and/or power flow constraint on the transmission system. Protection systems dependent on communications cannot ensure the equipment is adequately protected and the OGCC will lose visibility of the status of the equipment and system power flows. In turn, this will result in a negative impact to system reliability and expose Hydro One and its customers to the loss of redundancy which can lead to equipment being forcibly removed from service.

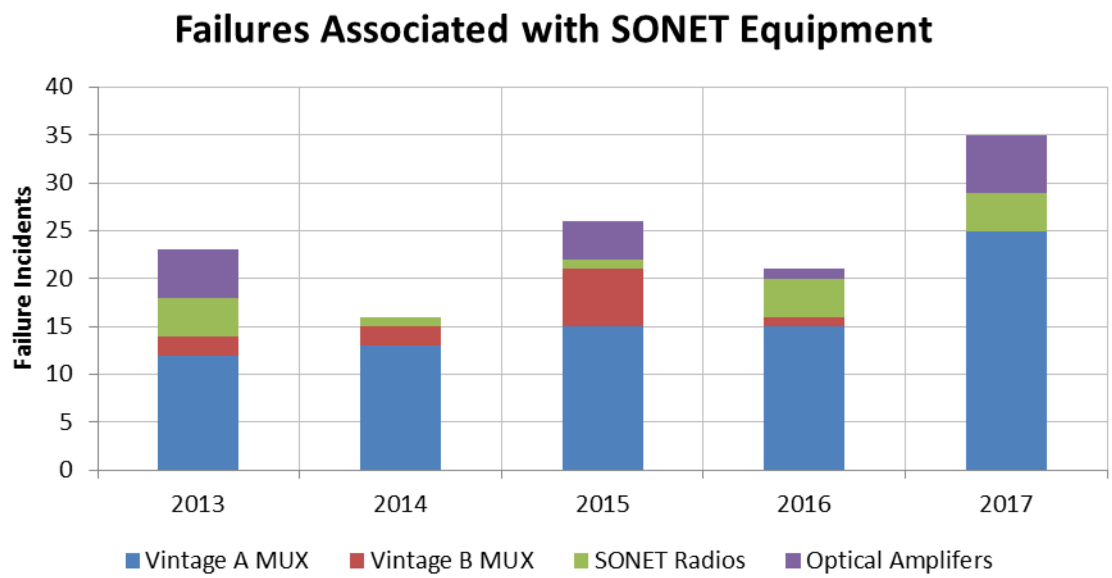


Figure 1 - Failure Incidents for SONET Equipment

Investment Description

Given the obsolescence of both the technology and network equipment on which SONET is built, Hydro One has developed the Project to replace the Legacy System with a modern solution. Implementation in the short and mid-term will begin with the replacement of legacy SONET equipment on Rings 1-9 taking into account other telecom sustainment needs and direction of the strategic expansion of the network. More specifically, the Project will replace the first vintage of SONET multiplexers that have been in service for close to 20 years with a new packet-based technology solution at 73 stations. The Project’s scope includes the necessary work to evaluate available technologies in the market, lab evaluations for proof of concept and field trials at select Hydro One transmission station(s) in order to validate the solution to be deployed. Once the new technology platform that satisfies the technical requirements is determined by the end of 2019, an overall implementation and staging plan will be developed, followed by multiyear systematic replacements. The technology evaluation will allow Hydro One to

be in an informed position to implement a viable technology in an orderly manner, and to mitigate operational impacts to the transmission system.
Based on the volume and complexities of the changeover, it is anticipated that it will take until 2024 to migrate communication services to the new platform for all nine rings of the communication network. As the network undergoes this changeover there will be a period of overlap when both the existing and the new platform will need to be operated and maintained.

Hydro One has completed the technical evaluation of available technologies, selected potential technologies, and conducted lab testing to demonstrate proof of concept as part of the development phase of the Project. Currently, field trials at being conducted at Claireville TS to further validate the technologies to be selected for deployment.

Outcome

The Project will result in Hydro One’s ability to support safe and reliable operation of the transmission system by migrating power system telecom services from Hydro One’s legacy SONET system to a new technology platform. In addition to its utilization for protection and SCADA systems, the new technology will also enable the cost-effective deployment of applications that require modern IP connectivity and eliminate the performance failures currently attributed to the older multiplexer equipment.

The following table presents anticipated benefits as a result of the Project in accordance with the OEB’s Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• Maintain telecommunication reliability of the protection and SCADA systems thereby maintaining the quality of service to customers.
Operational Effectiveness	• Maintain reliability of the transmission system by ensuring the communication network used for protection, control and monitoring of the grid is reliable.
Public Policy Responsiveness	• Hydro One is obligated to build and maintain a redundant communication/protection system to ensure that Hydro One meets the transmission system performance standard of NERC TPL-001. If the cable begins to break down, it must be fixed.

C. EXPENDITURE PLAN

Table 2 below presents forecasted costs for the Project. Planned costs are currently based on previous SONET implementations. The “Previous Years” costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year. These costs include the development phase cases that cover evaluation, testing and proof of concept. The test period costs include the implementation costs which involve engineering, procurement and construction. Costs noted in “Forecast 2025+” are project costs forecast beyond 2024. Final costs of the project will be based on the selected technical solution that will be determined at the conclusion of the development phase. Detailed estimates will also be prepared following the conclusion of the development phase.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	5.4	4.3	27.1	28.7	29.3	29.3	0.0	124.2
Less Removals	0.1	0.2	1.1	1.1	1.2	1.2	0.0	4.8
Gross Investment Cost	**5.4**	**4.1**	**26.0**	**27.6**	**28.1**	**28.1**	**0.0**	**119.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**5.4**	**4.1**	**26.0**	**27.6**	**28.1**	**28.1**	**0.0**	**119.3**

[1] *Includes overhead at current rates.*

D. ALTERNATIVES

Alternative 1: Reactive Replacement of Failed SONET Equipment involves replacing the legacy SONET equipment as it fails. This alternative has been rejected as reactive replacements result in unplanned equipment outages that negatively impact communication system performance and customer satisfaction. Repair times can be longer due to material sourcing delays and resource availability. Because SONET equipment is facing obsolescence, Hydro One's inventory of some spare parts is diminishing, further reducing the viability of a reactive replacement approach.

Alternative 2: Planned SONET Replacement is a preferred undertaking. This alternative will replace the legacy SONET system with new packet-based technology. It allows Hydro One to maintain the reliability of the transmission system. Replacements will be coordinated, thereby, scheduling and reducing outage impacts which will in turn alleviate the impact on communication system performance and Hydro One's customers. Complete replacement will also enhance the capability of the communication network resulting in utilization of communication infrastructure for future communication applications.

E. EXECUTION RISK AND MITIGATION

The main risk to the Project is finding a solution that satisfies Hydro One's functional and economical requirements. The developmental phase of the Project will find a technology that will fulfill these requirements by the end of 2019 before pursuing implementation.

SR-12 Telecom Performance Improvements

Start Date:	Q1 2021	**Priority:**	Medium
In-Service Date:	Q4 2023	**3 Year Test Period Cost ($M):**	6.5
Trigger(s):	Strategic, System Renewal		
Outcomes:	Maintain reliability of the communication network, maintain customer satisfaction, more reliable SONET network which will be supported by robust and reliable fibre cable infrastructure		

A. OVERVIEW

Telecom Performance Improvements project (the "Project") involves the replacement of obsolete digital microwave links with optical ground wire ("OPGW") on Ring 6 of the Synchronous Optical Network ("SONET") system.

Hydro One's SONET system is supported by physical infrastructure that establishes the communication medium that links transmission stations and control centers. A vast majority of these links utilize Hydro One owned or leased fibre-cable infrastructure, however, certain links are microwave based. While the Legacy SONET System Replacement project (SR-11) involves the replacement of end multiplexer equipment with a new technology, this Project establishes more robust and reliable fibre-based communication links within the above mentioned Ring.

The associated equipment of these microwave links is at its End of Life ("EOL") or, in some segments, soon approaching EOL due to the fact that assets:

- Have reached its Expected Service Life ("ESL"),
- Are technologically obsolete, and
- Have experienced higher rate of failures of SONET system's digital microwave radios which resulted in multiple power system telecom services being rendered unavailable until repairs were carried out.

The above facts make the reliability risk high. Loss of power system telecom services which include communications channels for protection systems can result in the removal of power system elements from service and/or power flow constraints on the transmission system (as protection systems dependent on communications cannot protect the equipment and the OGCC loses visibility of the status of the equipment). In turn, this can result in a negative impact to the reliability of the transmission grid and potentially expose Hydro One and customers to forced outages or a less reliable grid configuration due to the loss of redundancy. In addition to the high reliability risk, these microwave links are bandwidth bottleneck for the SONET network, limiting the full utilization of capacity of the SONET Rings.

In light of the foregoing, the Project is needed to improve the network performance in order to maintain the communication network's reliability. Hydro One has evaluated various alternatives for the Project, as described below, and concluded that proactive replacement of the obsolete ESL equipment is the most cost effective and efficient undertaking. The projected costs of the Project are estimated to be $6.5 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

Hydro One's communication network is based on SONET technology and is primarily utilized by protection systems, and SCADA monitoring systems. Additionally, it is used for communicating non-operational data, business data, voice and security information, and is used as backup for the provincial mobile radio system. The system includes multiplexers, optical amplifiers, digital microwaves and 48Vdc backup power supply (battery and charger systems). The network topology is such that stations are connected in the form of a ring to provide redundant communication links that can stretch up to hundreds of kilometers long across the province.

Hydro One's SONET network has a number of digital microwave links that were originally deployed where either fibre-based infrastructure was not economically feasible to install or third party leased fibre was not available. The associated digital microwave equipment is at EOL having reached its ESL and being technologically obsolete. Hydro One takes into account asset age, installed base, strategic spares, rate of failures, compliance, functionality, vendor support, manufacturer recommendations and historical asset retirement in order to determine EOL and to plan asset replacements. Field deficiency reports, trouble calls and failure incidents provide an indication of the overall condition of the power system telecom assets. The ESL for most of the digital microwave equipment is 15 years.

These failures have resulted in multiple power system telecom services being rendered unavailable until repairs were carried out. Loss of power system telecom services which include communications channels for protection systems can result in the removal of power system equipment from service and/or power flow constraint on the transmission system (as protection systems dependent on communications cannot protect the equipment and the Ontario Grid Control Centre ("OGCC") loses visibility of the status of the equipment).

Investment Description

As described above, the Project is needed to improve the network performance in order to maintain the communication network's reliability. The Project is paced such that the last major microwave links will be removed by 2023.

Digital microwave systems have been part of SONET Rings 4, 6 and 8 which provide a microwave radio path between stations as opposed to fibre cable links. Most of the microwave equipment is on SONET Ring 6 and 8. Replacement of microwave links on Ring 8 with OPGW is already underway leaving Ring 6 with major links to be removed on the SONET system by 2019. The investment is paced in such a way that following the replacement of microwave equipment on Ring 8 with more reliable and robust fibre-based links, work on Ring 6 will begin. Investment for the replacement of the last microwave link in Ring 4 is also in Hydro One's Business Plan that is targeted for completion by 2023. Table 1 below identifies the work that will be completed under this project.

Table 1 - Telecom Performance Improvement Projects

Circuits	Project Description	Project In-Service Year
B22D	Replacement of the remaining obsolete digital microwave radios on Ring 6 with the installation of OPGW on B22D	2022

Outcome

The Project will result in robust and reliable fibre-optic based communication infrastructure that will maintain transmission system reliability. Additionally, telecommunication service outages will be reduced and fewer inspections and repairs of microwave link equipment will be required.

The following table presents anticipated benefits as a result of the Project in accordance with the OEB's Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• Maintain telecommunication reliability and the quality of service provided to customers.
Operational Effectiveness	• Maintain reliability of the transmission system by maintaining the reliability of the communication network.
Financial Performance	• Avoid maintenance costs associated with obsolete asset.

C. EXPENDITURE PLAN

Table 2 summarizes historical and projected spending on the aggregate project level. Planned costs are currently based on estimates from previous projects. Final costs will be based on detailed estimates prior to project execution. The "Previous Years" costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	0.0	0.0	1.0	5.8	3.8	0.0	0.0	10.5
Less Removals	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.4
Gross Investment Cost	**0.0**	**0.0**	**0.9**	**5.5**	**3.7**	**0.0**	**0.0**	**10.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**0.0**	**0.9**	**5.5**	**3.7**	**0.0**	**0.0**	**10.1**

[1] *Includes overhead at current rates.*

D. ALTERNATIVES

Alternative 1: Reactive Repair of SONET Equipment involves repairing microwave links as they fail. This alternative has been rejected as Hydro One will be unable to maintain the required performance of the communication networks supporting protection and control systems that are reliant on the microwave links. This approach would lead to an unacceptable level of risk to system reliability.

Microwave equipment is obsolete and vendor support is diminishing. This results in longer repair times during which the equipment is out of service and there is loss of redundancy in that SONET ring. This is undesirable level of equipment performance as it degraded the reliability of the protection systems in the area.

Alternative 2: Planned Replacement of Microwave Links is a preferred undertaking. This alternative will replace SONET microwave links with OPGW as it provides robust and reliable communication links for Ring 6. It also allows for the replacement to be coordinated thereby scheduling and reducing outage impacts which will alleviate the impact on telecommunication system performance and Hydro One's customers.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the Project are: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges, or regulatory approvals. A thorough risk assessment workshop is performed during the initial project planning phase where all known risks are identified and mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize to a minimum the loss of supply to the customer. The plan might include switching a customer to an alternative supply, the construction of a temporary by-passing circuit or supply of portable generation that will maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. Another example is the involvement of real estate from the project inception. It allows for the early identification of real estate issues, such as missing or inadequate land rights. Once the issue is identified, Hydro One tries to resolve it prior to execution of the project.

SR-13 ADSS Fibre Optic Cable Replacements

Start Date:	Q3 2018	**Priority:**	High
In-Service Date:	Q4 2022	**3-year Test Period Cost ($M):**	15.1
Trigger(s) : System Renewal			
Outcomes: Maintain reliability, improved safety			

A. OVERVIEW

Hydro One utilizes fibre optic cable infrastructure including Hydro One owned/operated aerial fibre optic cables as well as fibre strands acquired through indefeasible right of use ("IRU") from telecom providers. An IRU is a permanent contractual agreement that cannot be undone, between the owners of a communications system and a customer of that system. Hydro One's aerial fibre optic cables include both Optical Ground Wire ("OPGW") and All-Dielectric Self-Supporting ("ADSS") types. Hydro One has been phasing out ADSS fibre optic cables from its asset base due to high risks to reliability and safety. The remaining sections of ADSS fibre cable have deteriorated significantly over the recent years. Excessive premature wear and tear has compromised the asset and hence Hydro One's ability to operate the transmission system reliably. In order to maintain the reliability of the transmission system, there is a need to replace remaining sections of Hydro One owned ADSS fibre optic cable.

B. NEED AND OUTCOME

Investment Need

This investment is needed to mitigate the reliability and safety risk posed by deteriorating ADSS fibre optic cables.

Hydro One's communication network is based on Synchronous Optical Network ("SONET") technology and is primarily utilized by protection systems, and SCADA monitoring systems, as well as for communicating non-operational data, business data, voice and security information, and is used as backhaul communication for the provincial mobile radio system. The network topology is such that communications among stations are connected in the form of a ring to provide redundant communication links that can stretch up to hundreds of kilometers across the province.

The SONET rings provide robust and reliable communication between transmission stations because of the reliable fibre optic cable infrastructure and network configuration that essentially provides redundancy paths for communications. Hydro One Networks utilizes approximately 3,900 kilometers of fibre optic cable infrastructure including Hydro One owned/operated aerial fibre optic cables as well as fibre strands acquired through IRU. Aerial fibre optic cable is primarily comprised of (i) OPGW technology with strands of fibre embedded inside of the shieldwire mounted on top of high-voltage transmission structures and (ii) ADSS fibre otpic cable that is attached to towers or poles typically below the phase conductors, with a small share being attached to low-voltage wood poles located along roadways and/or railways.

Hydro One’s fibre optic cable infrastructure includes approximately 160 km of ADSS type fibre cable. The ADSS cable along the Q25BM and Q29HM right of way (“ROW”) is an essential segment of the Ring 3 that spans from Hamilton, Niagara and the Southwest connecting many Bulk Electric System as well as load supply transmission stations, while the ADSS cable along circuits D6V and E9V connects Detweiler TS, Orangeville TS and Essa TS. Historical performances have shown that the mechanical aspects of the fibre cable have prematurely reduced the cable’s life span. Specifically, excessive vibrations have led to compromising the integrity of the cable itself as well as connection hardware. Inspections reveal damaged cables, missing or broken hardware assemblies on a yearly basis.

Figure 1 – ADSS Fibre Optic Cable Damage in 2017

The Expected Service Life (ESL) of fibre optic cable is based on the type of cable. The manufacturers' recommended ESL for OPGW is 40 years and 25 years for ADSS. Historical performance shows that the mechanical aspects of the fibre cable can prematurely reduce the cable's life span. In the case of ADSS cables, unusual mechanical stresses have resulted in high rate of premature failures before its ESL expired. ESL is now lowered to 15 years and it is used to trigger the asset condition assessment in the replacement decision making process.

Due to the high risks to reliability and safety posed by this degradation, Hydro One has been phasing out ADSS fibre cables from its asset base. The remaining sections of ADSS fibre cable have deteriorated significantly over the recent years. Excessive premature wear and tear has compromised the asset and hence placed at risk Hydro One's ability to operate the transmission system reliably. Annual helicopter patrols for inspections along the Q25BM/Q29HM and D6V/E9V ROW have shown a declining trend in the overall condition of the ADSS cable with damages to the cable jacket, fibre strands, as well as hardware assemblies.

Failures of ADSS cable would lead to loss of power system telecom services and loss of redundancy of protection systems leading to degraded reliability of communications for the transmission stations served by the cable. Degraded reliability is not desirable for transmission system operations and maintenance by the Independent Electricity System Operator ("IESO") and the Ontario Grid Control Centre ("OGCC") because it places the system at risk of forced outages due to second contingency resulting in complete loss of communication to multiple stations. Failure of one cable places the system in a high risk scenario should another failure occur on the ring, which in turn would lead to multiple power outages as a result of complete loss of communication. Failures of ADSS cable is also a safety risk as the cable can break and fall to the ground that can cause injury.

Keeping the existing configuration in place represents a major reliability risk. In order to maintain the reliability of the transmission system, there is a need to replace the remaining sections of ADSS cable with better performing OPGW.

Investment Description

This investment addresses the replacement of remaining deteriorated ADSS cable with optical ground wire, designed to current standards. The ADSS cable to be replaced by this project includes 60 km of ADSS cable along the Q25BM/Q29HM right of way as well as replacement of 98 km of deteriorated ADSS on circuits D6V and E9V between Detweiler TS, Orangeville TS and Essa TS. The remaining 5 km ADSS population will be included, where technically and financially feasible, as part of the Shieldwire Replacement Program. Asset condition information for power system telecom is discussed in TSP Section 2.2.1.5.

Keeping the existing configuration in place represents a major reliability risk to certain sections of the Hydro One SONET network. In order to maintain the reliability of the transmission system, remaining sections of ADSS cable will be replaced with better performing OPGW. Although both OPGW and ADSS have their own benefits and drawbacks, OPGW is the preferable replacement for the following reasons:

- Better suited for high voltage environments due to robust construction
- Less susceptible to vandalism
- Higher ESL

Outcomes

The following table presents anticipated benefits as a result of the Project in accordance with the OEB's Renewed Regulatory Framework:

Customer Focus	• Maintenance of system reliability and reduced risk of outages and safety concerns
Operational Effectiveness	• Maintain reliability of the transmission system through maintaining a reliable communication network by replacing poor performing and degraded ADSS cable.
Public Policy Responsiveness	• Hydro One is obligated to build and maintain a redundant communication/protection system to ensure that Hydro One meets transmission system performance standard of NERC TPL-001. If the cable begins to break down, it must be fixed.
Financial Performance	• Avoid Operations, Maintenance & Administration ("OM&A") costs associated with ADSS repairs required upon failures.

C. EXPENDITURE PLAN

Table 1 below presents forecasted costs of the Projects. The planned costs are based on estimated unit costs. Final costs will be based on detailed estimations performed prior to project execution. Controllable costs will be effectively managed during the execution of this project.

Previous year costs are associated with developing a detailed execution plan and estimated costs for the Q25BM/Q29HM portion of the work. Future year costs are for work execution costs with the bulk of engineering and procurement work to occur in 2020 and 2021, as well as the start of construction. The investment is paced to allow for timely cost estimation followed by complete execution of the replacement work. The majority of the construction work will be carried out in 2020, 2021 and 2022. Previous year costs are associated with developing a detailed execution plan and estimated costs for the D6V/E9V portion of the work followed by work execution costs until 2022.

Planned costs are based on the following sequence of work with work execution and construction spanning over multiple years:

- Estimation, preliminary planning/engineering
- Details design/execution planning/work execution/construction
- Wrap up/project closure activities

Table 1 - Total Project Costs

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	1.6	7.5	7.5	1.0	0.0	0.0	0.0	17.6
Less Removals	0.1	0.5	0.4	0.0	0.0	0.0	0.0	1.0
Gross Investment Cost	**1.5**	**7.0**	**7.1**	**1.0**	**0.0**	**0.0**	**0.0**	**16.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.5**	**7.0**	**7.1**	**1.0**	**0.0**	**0.0**	**0.0**	**16.6**

[1] Includes overhead at current rates.

D. ALTERNATIVES

Alternative 1: Reactive Treatment of ADSS Fibre Cable. Hydro One can repair or replace sections of fibre communication cable reactively upon failures. This alternative is rejected due to criticality of the fibre communication cable to the operation of the transmission system, the reliability risk associated with cable failure and undesirable OM&A costs of repairs.

Undesirable OM&A costs are costs associated with more than usual maintenance of an asset. Because of all the issues highlighted above, every year repairs are identified that need to be carried out on ADSS. Compared to OPGW, inspections are done but major repairs are not identified every year. In order to carry out this 'discovery' maintenance, crews have to first assess the extent of the damaged and come up with a plan to fix, mobilize, seek outages, parts, repair kits, etc. which comes out of our planned maintenance budget. Since the nature of the repair work is different than conventional PCT equipment failure, costs range from $20,000 to $100,000 per repair.

Alternative 2: Planned Replacement of ADSS Fibre Cable. This is the preferred alternative. Hydro One can replace approximately 60 km of ADSS cable along the Q25BM/Q29HM right of way, as well as 98 km of deteriorated ADSS cable on circuits D6V and E9V between Detweiler TS, Orangeville TS and Essa TS. This alternative will maintain the integrity of communication channels used for protection systems of the high voltage transmission system in turn, maintaining system reliability and avoid OM&A costs associated with ADSS repairs.

E. EXECUTION RISK AND MITIGATION

There is a risk to complete the project as planned due to potential delay in required circuit outages to carry out replacement work. Hydro One will manage and stage the project to ensure that outages are available in time. Availability of resources and other competing projects requiring similar resources is a risk to project priority and timely completion. Hydro One will develop a detailed project and resource plan in order to ensure resources are available.

SR-14 Mobile Radio System Replacement

Start Date:	Q1 2019	**Priority:**	Medium
In-Service Date:	Q4 2023	**3-year Test Period Cost ($M):**	15.2
Trigger(s): System Renewal			
Outcomes: New radio system**,** Increased reliability of communications during power outages and restoration efforts, Shorter outage duration as a result of effective communication between control centres and field staff			

A. OVERVIEW

This investment involves the procurement of a solution to replace the existing provincial mobile radio system. The existing radio technology that Hydro One uses for its private mobile radio system is obsolete and requires replacement when the strategic spares are exhausted in 2023. The planned mobile radio replacement project addresses the concerns regarding the end of life of the existing technology, the commercial unavailability of radio equipment in the 49 MHz frequency band and the condition of the deployed equipment by implementing a new technology solution to continue providing communications between control centres and field staff when maintaining and restoring transmission system assets.

B. NEED AND OUTCOME

Investment Need

Hydro One owns and operates a private radio system that is used for two-way voice communication between control centers and field crews. This system is used by forestry and lines crew during restoration efforts, emergency operations as well as day-to-day construction and maintenance work. The mobile radio provides coverage that exceeds the cellular coverage in remote areas and is often the only means of communications in these areas.

The existing radio technology Hydro One uses for its private mobile radio system is obsolete having reached end of vendor support ("EVS"). Equipment for the system is no longer manufactured, and Hydro One's strategic spares will only last up to five years from 2018. When the strategic spares have been exhausted in 2023, Hydro One will be unable to restore radio communications upon failure of equipment. This would render voice communication unavailable for field staff and control centers, especially in parts of the province where there is no cellular coverage. As a result, Hydro One will be unable to maintain transmission system equipment and/or restore power in remote areas in a safe and timely manner resulting in longer than expected outages. The potential reliability impact resulting from the EVS leads to the system being classified as having reached its end of life ("EOL").

The concerns of equipment at end of life, the commercial unavailability of radio equipment in the 49 MHz frequency band and condition of the deployed equipment necessitate an overhaul of the current provincial radio system. In light of the foregoing, a new technology solution is needed to continue providing communications between control centres and field staff when maintaining and restoring transmission system assets.

Investment Description

This investment will procure a solution to replace the existing provincial mobile radio system. The planned mobile radio replacement project will:

- Examine available technologies such as satellite based-communication, radio over IP, trunked radio system, and integrated solutions to the existing hand-held and in vehicles units used by field staff;
- Study the technical and economic feasibility of each of the viable technologies, select technology for small scale deployment as a proof of concept, with due consideration for future operating costs; and

- Carry out assessment to determine the required infrastructure that would be needed to ensure the necessary coverage is provided prior to new system's deployment.

The investment is paced to allow the new system to be fully tested prior to deployment. Multi-year deployment will also smooth the transition to the new system while utilizing the existing system to its full extent. It is expected that the new system will be fully implemented by 2023.

Outcomes

By replacing the existing provincial mobile radio system, Hydro One will continue to provide voice communication between control centers and field crews maintaining efficiency and safety during restoration efforts, emergencies as well as routine work. This in turn will allow Hydro One to keep power outage durations to a minimum to the benefit of customers.

The following table presents anticipated benefits in accordance with the OEB's Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• Maintain the ability to restore transmission equipment in remote areas in a timely manner to minimize impacts on the system and customers
Operational Effectiveness	• Maintain equipment outage durations and power restoration times.
Financial Performance	• Work efficiency will result is lower Operations, Maintenance, and Administration ("OM&A") costs associated with power restoration and emergency operations.

C. EXPENDITURE PLAN

Table 1 below presents forecasted costs of the Project. Planned costs are based on past system deployment costs. Final costs will be based on the technology solution selected to replace the existing system. Hydro One will follow its established estimating process and project management practices to minimize controllable costs.

The previous years' costs (2019) are for the development phase of the project where a new technology will be evaluated, tested and estimated to determine system deployment costs. Planned costs in 2020 and beyond are costs related to province-wide deployment of the new solution. The project is planned for completion in 2023, and lower costs will be expected that year as the project wraps up.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	0.7	3.0	6.5	6.4	4.2	0.0	0.0	20.6
Less Removals	0.0	0.1	0.3	0.3	0.2	0.0	0.0	0.8
Gross Investment Cost	**0.6**	**2.9**	**6.2**	**6.1**	**4.0**	**0.0**	**0.0**	**19.8**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.6**	**2.9**	**6.2**	**6.1**	**4.0**	**0.0**	**0.0**	**19.8**

[1] *Includes overhead at current rates.*

D. ALTERNATIVES

Alternative 1: Maintaining the Existing System. Hydro One can maintain the existing provincial mobile radio system. This alternative is rejected as Hydro One would be unable to restore failed radio equipment in fleet trucks and base station beyond 2023. This would render voice communication unavailable for field staff and control centers. As a result, Hydro One would be unable to maintain transmission system equipment and/or restore power in remote areas in a safe and timely manner resulting in longer than expected outages.

Alternative 2: Replace Legacy Mobile Radio System. This is the preferred alternative. Hydro One can replace the existing legacy provincial mobile radio system with a new system. This alternative involves procuring a fully integrated solution that meets the communication needs of the control centre dispatch and field crews using commercially available and supported technology. This approach allows Hydro One to continue to provide voice communications between field staff and control centers during restoration efforts, emergency operations as well as day-to-day construction and maintenance work.

E. EXECUTION RISK AND MITIGATION

The risk to the implementation of this investment is finding a technologically and economically feasible solution. For example, a new system at higher frequency may require proportionally larger infrastructure, resulting in higher costs than estimated. Hydro One will execute a developmental phase of the project to explore the available technologies that meet technical and business requirements before pursuing implementation.

SR-15 Telecom Fibre IRU Agreement Renewals

Start Date:	Q1 2021	**Priority:**	High
In-Service Date:	Ongoing Program	**3 Year Test Period Cost ($M):**	11.3
Trigger(s): Contractual, System Renewal			
Outcomes: Maintained reliability of communications systems			

A. OVERVIEW

This investment involves the renewal of leases of fibre acquired through Indefeasible Right of Use ("IRU") agreements for use in Hydro One's telecommunication network. Indefeasible right of use is a permanent contractual agreement that cannot be undone, between the owners of a communications system and a customer of that system. The agreements for the leased fibre used in Hydro One networks will begin to expire in 2021. These agreements require renewal upon expiration in order to continue to provide telecommunication for reliable network operation.

B. NEED AND OUTCOME

Investment Need

Hydro One's Synchronous Optical Network ("SONET") used for station to station and control centre telecommunication utilizes approximately 1,700 km of fibre acquired through IRU agreements. These agreements were negotiated for initial terms of 20-25 years that are due for renewal starting 2021. The last scheduled renewal is planned to occur in 2026. In order to continue to provide telecommunications for the reliable operation of the transmission system, there is a need to renew these agreements that provide for the necessary fibre infrastructure underpinning power system protection, control and monitoring applications.

In certain locations, Hydro One is leveraging the existing shieldwire replacement program to install new Optical Ground Wire ("OPGW") in place of the shieldwire. In locations where shieldwire replacement is necessary and a fibre optic communication channel is required for telecommunication purposes, Hydro One will install OPGW, which consists of overhead shieldwire with a core containing fibre optic strands. Where the new OPGW will make the leased IRU fibres redundant, leases for that section of cable will not be renewed. Leveraging the shieldwire replacement program allows Hydro One to provide more reliable communication and avoid renewal costs. IRU fibre cables are generally located along roads and railroads on wood poles, while OPGW is installed on top of high voltage transmission structures, making them less prone to outages caused by accidents. When considering whether a specific site is suitable for this approach, the following considerations will be assessed:

- Whether the shieldwire replacement program is scheduled to occur within a reasonable timeframe (5-7 years).
- Whether there are communication system reliability issues associated with existing leased fibre.

Investment Description

The need to renew leased fibre in each geographical area will be assessed, and renewals will be pursued where justified in order to continue to provide telecommunication for reliable network operation. Where the shieldwire replacement program will install OPGW in the near future, the lease will not be renewed.

Hydro One leases certain strands in the IRU fibre cables, which are owned and maintained by others. Leased IRU fibres are owned by Hydro One Telecom, a subsidiary of Hydro One, as well as Bell, Eastlink and Cogeco, among others. Where the fibre is owned by parties other than Hydro One Telecom, Hydro One Telecom will lease the fibre and in turn lease the fibre to Hydro One under service-level agreements.

The pacing of the investment is based on when the initial term ends for each section of the fibre. Contracts will expire between 2021 and 2026, triggering a concurrent renewal requirement. Therefore, the need for renewals will be assessed according to this timeline.

Outcomes

This investment will allow Hydro One to provide telecommunication for transmission system operations by providing the required fibre infrastructure in the most economical manner.

The following table summarizes the anticipated benefits as a result of the project in accordance with the OEB's Renewed Regulatory Framework:

Customer Focus	• Reduce risk to the operation of the transmission system by ensuring leased fibres are secured under contract.
Operational Effectiveness	• Maintain reliability of the transmission system by providing fibre cable for telecommunication used for protection, control and monitoring of the grid.
Financial Performance	• Minimize controllable costs through the use of Hydro One Telecom in the negotiation of IRU agreements.

C. EXPENDITURE PLAN

Planned costs are based on initial term one-time lump sum payments. The scheduling of the expenditure plan is based on the expiration dates of the initial term for each of the IRU fibre segments. Contracts for certain segments start expiring in 2021, triggering a need for renewals in that year while the last of the segments initial term expires in 2026.

As in the past, Hydro One will engage Hydro One Telecom to negotiate extensions and prices under existing Hydro One – Hydro One Telecom service-level agreements.

Table 1 - Total Investment Cost

($ Millions)[1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	0.0	0.0	2.8	8.5	2.6	1.5	0.0	15.4
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**0.0**	**2.8**	**8.5**	**2.6**	**1.5**	**0.0**	**15.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**0.0**	**2.8**	**8.5**	**2.6**	**1.5**	**0.0**	**15.4**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown
[2] Includes Overhead at current rates.

D. ALTERNATIVES

Alternative 1: Construct Fibre Cable Infrastructure. Construct required fibre cable infrastructure to support the Hydro One SONET network requirements. This alternative is rejected as construction of Hydro One owned fibre cable infrastructure is not economically feasible to completely displace all IRU fibre.

Alternative 2: Renew Subset of Fibre IRU Agreements. This is the preferred alternative. Renew a subset of IRU contracts where it is not economically feasible to build Hydro One owned fibre cable infrastructure. This alternative will allow Hydro One to maintain the reliability of the transmission system by continuing to provide telecommunications infrastructure for protection, control and monitoring of transmission system assets. Where prudent and feasible, fibre optic cable infrastructure will be constructed by Hydro One that would eliminate the need of renewals for certain IRU contracts.

E. EXECUTION RISK AND MITIGATION

Completion risks involve paying elevated renewal prices if negotiations are delayed until the end of the lease period, and potential high risk to the operation of the transmission system if extensions are not sought prior to the expiration of the lease. Renewal costs will need to be negotiated with third parties in a timely manner to ensure that there is no interruption in communications. If delayed until the end of the lease period, Hydro One will face increased pressure to secure these fibres under contract. These risks will be mitigated by adopting a pro-active approach to the assessment and renewal of leased fibre segments, and leveraging Hydro One Telecom to seek these IRU renewals.

SR-16 NERC CIP-014 Physical Security Implementation

Start Date:	Q1 2020	**Priority:**	High
In-Service Date:	Program	**3 Year Test Period Cost ($M):**	54.0
Trigger(s):	Compliance, Strategic, Customer Satisfaction, Corrective Maintenance, Reliability and Environment		
Outcomes	Compliance with NERC CIP-014; ensure security of crucial transmission facilities		

A. OVERVIEW

Hydro One's transmission system is a critical asset for the Province; it comprises the Bulk Electric System ("BES"), which requires compliance with reliability standards established by the North American Electric Reliability Corporation ("NERC") to ensure the integrity of the interconnected North American BES. NERC Critical Infrastructure Protection - 014 ("CIP") standard requires entities, such as Hydro One, to identify and protect transmission stations and transmission substations (and their associated primary control centers) that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation or cascading effects to the BES. The CIP-014 Physical Security Implementation project (the "Project") involves specific physical security improvements to Hydro One transmission stations and control centres that are subject to CIP-014 compliance. Hydro One identified 26 stations and 1 control centre that meet criteria of CIP-014 and as such are subject to NERC CIP-014 requirements. The Project ensures that Hydro One continues to be compliant with the regulatory requirement thereby, ensuring that the critical transmissions assets are safe and secured.

B. NEED AND OUTCOME

Investment Need:

Hydro One operates one of the largest transmission systems in North America. Hydro One's transmission system extends to most of the Province and operates in diverse geographic and climactic conditions. Hydro One's transmission system is a critical asset for the Province, among others, it comprises the BES, which requires compliance with reliability standards established by the NERC to ensure the integrity of the interconnected North American BES. The reliability framework for Ontario's electricity transmission system is based on the reliability standards established by NERC, which have been adopted and are enforced in Ontario by the Independent Electricity System Operator ("IESO").

The *Electricity Act, 1998* ("Electricity Act") grants the IESO jurisdiction to maintain the reliability of the IESO-controlled grid and the statutory power to create market rules establishing and enforcing standards and criteria relating to the reliability of the electricity service or the IESO-controlled grid. The Government of Ontario has also directed the IESO to coordinate standards development activities with, among others, the NERC by assigning it the statutory object to participate in the development by any standards authority of criteria and standards relating to the reliability of the integrated power system. NERC is identified in the *Electricity Act* as standards authorities that approve standards and criteria relating to the reliable operation of the integrated power system. In addition to other reliability requirements in the market rules and market manuals, the market rules incorporate NERC reliability standards and criteria by reference. Subject to the IESO's applicability determination, these standards and criteria form part of the law in Ontario. The market rules assign to the IESO various functions, powers and authorities to supervise, administer and enforce the market rules. The market rules also provided the IESO with the general power to undertake such monitoring as it considers necessary to determine whether market participants, such Hydro One, are complying with the market rules. This power necessarily extends to those provisions mandating reliability standards compliance in Ontario.

With an increased focus on physical security, NERC has developed physical security reliability standards to ensure the critical infrastructure of the utilities is kept secured and safe. In 2014, NERC released the CIP-014 standard that provides guidance to utilities in addressing the protection of key physical assets. The stated purpose of the standard and its requirements is to identify and protect transmission stations and transmission substations (and their associated primary control centers) that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation or cascading effects to the BES.

In accordance with CIP-014, Hydro One is required to perform an initial threat risk assessment of its transmission stations and transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in CIP-014. The risk assessments consist of a transmission analysis designed to identify the transmission station(s) and transmission substation(s) that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or cascading within an Interconnection. Furthermore, CIP-014 also requires Hydro One to have an unaffiliated third party verify the results of the risk assessment that has been performed.

Investment Description

Hydro One has identified 26 stations and 1 control centre that meet criteria of CIP-014 and as such are subject to NERC CIP-014 requirements. Hydro One performed a threat risk assessments of these stations and the control center in April 2016. A Threat Risk Assessment (TRA) is a detailed risk assessment process performed by Hydro One security specialists who evaluate, among other things, Hydro One transmission stations for security gaps. In accordance with the CIP-014 requirements, the results of the risk assesments are then verified by an independent third party. Hydro One's TRA was reviewed and verified by Ontario Provincial Police.

The Project will implement physical security measures, based on the recommendations of the TRA, on these critical stations. Providing adequate physical security to Hydro One critical stations will ensure operational effectiveness, as well grid resiliency and reliability to Hydro One customers.

Specific physical security improvements will vary by station to ensure NERC compliance and may include:

- Physical barriers such as upgraded fences, gates, and jersey vehicle barriers which will act as the outermost layer of security.
- Surveillance cameras with thermal night vision and motion detection used to deter unwanted entry will provide incident verification and historical analysis.
- Security lighting provides visual-assessment during darkness and acts as a deterrent.
- Physical Access Control System such as electronic door controls, magnetic card readers and access cards will trigger alerts in response to detected unauthorized access.
- Extending the height of the conduit protecting the fiber inside an optical ground wire cable that provides the supervisory, teleprotection, corporate and power system IT communication will reduce the possibility of tampering or malicious damage.

Outcome

The Project will ensure that Hydro One is compliant with the regulatory requirements of NERC CIP-014, while ensuring adequate physical protection to Hydro One critical transmission assets. Furthermore, the Project will sustains at the least the same level of system reliability and resiliency by minimizing physical threats and vulnerabilities that might occur as a result of a physical attack and cause instability and impact customers.

The following table presents the anticipated benefits as a result of the Project in accordance with the Ontario Energy Board's Renewed Regulatory Framework:

Customer Focus	• Maintain system reliability and supply to customers by ensuring secure operation of critical transmission facilities.
Operational Effectiveness	• Maintain operational effectiveness, as well grid resiliency and reliability.
Public Policy Responsiveness	• Comply with NERC CIP-014 regulatory requirements.

C. EXPENDITURE PLAN

Specific physical security improvements will vary by station to ensure NERC compliance and are evaluated on site-by-site basis and will affect the total project cost.

Table 1 below presents forecasted costs for the Project. Costs for the Project are based on historic costs and future needs.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years[1]	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	-	18.0	18.0	18.0	0.0	0.0	-	54.0
Less Removals	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Gross Investment Cost	**-**	**18.0**	**18.0**	**18.0**	**0.0**	**0.0**	**-**	**54.0**
Less Capital Contributions	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Net Investment Cost	**-**	**18.0**	**18.0**	**18.0**	**0.0**	**0.0**	**-**	**54.0**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown
[2] Includes Overhead at current rates.

D. ALTERNATIVES

The Project is non-discretionary and, as such, no other alternatives have been considered. A failure to perform the proposed security measures will result in non-compliance with NERC CIP-014 requirements and might expose Hydro One 26 stations and 1 control centre to physical attacks and other security threats.

E. EXECUTION RISK AND MITIGATION

The risk to this project includes scheduling of resources to complete all the necessary work. This risk is mitigated through coordinated planning and scheduling of TRAs.

SR-17 NERC CIP Transient Cyber Asset Project

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	December 2020	**3 Year Test Period Cost ($M):**	3.5M
Trigger(s):	Compliance, Reliability, Customer Satisfaction		
Outcomes:	Compliance with NERC Reliability Standards; ensure reliability and security of Bulk Electric System		

A. OVERVIEW

The Bulk Electric System ("BES") and related assets comprising Hydro One's transmission facilities are subject to compliance with applicable reliability standards, which are established by the North American Electric Reliability Corporation ("NERC") to ensure the integrity of the interconnected North American BES and enforced in Ontario by the Independent Electricity System Operator ("IESO"). To ensure Hydro One's compliance with NERC Critical Infrastructure Protection ("CIP") standards CIP-010 (*Cyber Security – Configuration Change Management and Vulnerability Assessments)* and CIP-003 (*Cyber Security – Security Management Controls*), the NERC CIP Transient Cyber Asset Project (the "Project") is intended to design and implement Hydro One's long-term transient cyber asset ("TCA") and removable media solution for medium impact BES sites (under CIP-010) and low impact BES sites (under CIP-003).

TCAs are those devices that interface with or run applications that support BES cyber systems and that are capable of transmitting executable code to BES cyber assets or systems. They range from specially-designed devices for maintaining BES equipment to an end-user platform such as a laptop, desktop or tablet. Removable media include compact disks, floppy disks, USB flash drives, external hard drives, and other memory cards or drives that contain nonvolatile memory. In contrast to devices that are network-connected on a more permanent basis, the use (or misuse) of TCAs and removable medium presents particular challenges in terms of security management and control. For instance, it is difficult to ensure that intermittently-connected mobile devices (e.g. laptops) remain appropriately updated and patched, thus making them susceptible to malwares that may in turn introduce cyber threats onto the Hydro One network. Similarly, the improper use of removable media such as CDs and USB flash drives (if undetected) not only risks the transmission of malware onto the network, but can also lead to the unauthorized exfiltration of highly sensitive BES system information off of the network. Through this Project, Hydro One will address the long-term secure management and control of TCA and removable media that are directly connected to its BES cyber systems for 30 consecutive calendar days or less at a time, in compliance with NERC CIP requirements, and in support of the ongoing reliability and security of Ontario's BES.

B. NEED AND OUTCOME

Investment Need

Hydro One operates one of the largest transmission systems in North America. Hydro One's transmission system extends to most of the Province of Ontario, serving a large number of customers and encompassing immense geographic areas. As a critical asset for the Province, the BES that comprises Hydro One's transmission facilities is subject to a rigorous set of regulatory and technical criteria, including the NERC-established and IESO-enforced reliability standards. As part of such standards, applicable CIP requirements impose various compliance obligations on Hydro One with respect to critical infrastructure protection and cyber security, including the mitigation of potentially serious threats stemming from the misuse and/or inadequate control of TCAs and removable media.

While most BES cyber assets and systems are isolated and protected from external public or untrusted networks, TCAs and removable medium represent a potential "back door" for cyber threats and intrusions. As indicated above, their inherent portable and mobile nature, combined with intermittent network-connectivity, poses serious challenges with respect to security updates and patching as well as ongoing tracking and control. At the same time, TCAs and removable media are indispensable to BES operations, given they are often the only way to transport files to/from secure areas or cyber assets for purposes of maintaining, monitoring or troubleshooting critical systems. As such, NERC CIP standards specifically require BES facility owners and operators to evaluate and mitigate the risks associated with such devices in relation to BES sites and cyber systems.[1]

Since CIP-010 came into effect in relation to Hydro One's medium impact BES sites in 2017, the utility has designed and implemented a temporary method to achieve compliance, which involves and relies on the use of a portable USB solution by field personnel to ensure the secure connection to BES cyber systems. In addition, pursuant to NERC CIP-003, similar compliance obligations will begin to apply to Hydro One's low impact BES sites by the end of 2019. Consequently, Hydro One has also been introducing the aforementioned USB-based method at low impact BES sites, so that interim compliance for both medium and low impact sites can be met according to applicable timelines while this Project is being undertaken to arrive at a sustainable solution.

While an important short-term tool for meeting NERC requirements and protecting the BES' cyber security, the USB method is not intended for or capable of serving Hydro One's compliance and operational needs on an ongoing basis. Rather, it is a bridge to a sustainable and long-term compliance solution, as proposed through this Project.

As described below, the proposed long term solution will enable the secure connection (both direct and indirect) of TCAs and removable media to all BES substation power

[1] While NERC CIP-010 applies to both high and medium impact sites, Hydro One's high impact sites are already considered compliant, and therefore only its medium impact sites need to be brought into compliance with CIP-010. Further, CIP-003 applies to low impact sites, which are also covered by this investment, as detailed herein.

assets and systems, by providing the necessary security measures such as logging and monitoring of access, in satisfaction of applicable NERC CIP requirements.

Investment Description

Through this Project, a Privileged Access Management ("PAM") solution will be developed and deployed to Hydro One's medium and low impact BES sites[2]. Specifically, field personnel requiring access to BES cyber systems to perform maintenance and sustainment activities will physically and securely connect to a PAM server at the applicable site. As its name suggests, this solution will administer user privilege or access based on the appropriate approval and authorization being in place as part of a systematic access and change management framework. Key benefits of PAM include two-factor authentication, protected passwords, and a robust audit trail of system access and user actions.

Upon completion of the Project by the end of 2020, access to Hydro One's medium and low BES impact cyber assets as well as associated Protected Cyber Assets ("PCA")[3] will be accessed entirely through the PAM application, therefore eliminating the risks and threats stemming from the intermittent connections of TCAs and removable media. Prior to users being able to access BES, Electronic Security Perimeter ("ESP")[4] or PCA, PAM will require users to undergo strong, multi-factor authentication[5], in adherence of the continuous 'least privileged" concept (i.e., granting a user only those access rights that are must-haves for a given job function), enforcing robust policy over who can access

[2] As of March 2018, Hydro One has 42 stations that are categorized as medium impact BES sites, and 57 as low impact BES sites.
[3] Protected Cyber Assets, or PCAs, refer to cyber assets connected using a routable protocol within or on an Electronic Security Perimeter ("ESP") that is not part of the highest impact BES cyber system within the same ESP. The impact rating of PCAs is equal to that of the highest rated BES cyber system in the same ESP.
[4] An Electronic Security Perimeter, or ESP, refers to the logical border surrounding a network to which BES cyber systems are connected using a routable protocol.
[5] Multi-factor authentication is an authentication method in which a computer user is granted access only after successfully presenting two or more pieces of evidence to an authentication mechanism.

privileged accounts, and restricting privileged users' authorized activities to only those required for their jobs as identified through Request for Change ("RFC") tickets. No direct connections to BES cyber assets will be permitted unless in the event of a CIP "exceptional circumstance".[6] In addition, the proposed solution will eliminate the use of static passwords, and provide for the monitoring and logging of access through a detailed audit trail of privileged log-in sessions and activities. The PAM solution will meets all applicable NERC requirements with respect to TCA management and authorization, malicious code mitigation, and software vulnerability mitigation.

Outcome

When completed, the Project will eliminate the concept of and risks associated with transient devices, since devices that connect to Hydro One's BES cyber systems through a PAM server will no longer be considered TCAs, and any vulnerabilities or malicious code potentially existing on such devices will pose no direct threat to the relevant BES cyber assets. The detailed records to be generated by PAM for all user sessions, including activity /security logs will support real-time event correlation and alerts, as well as ongoing review and audits.

The following table presents anticipated benefits as a result of the Program in accordance with the OEB Renewed Regulatory Framework:

Customer Focus	• Maintain system reliability for customers by ensuring the secure and uninterrupted operation of BES transmission facilities.
Operational Effectiveness	• Maintain operational effectiveness, reliability and resiliency against potential cyber threats by mitigating the risks

[6] A CIP exception circumstance refers to a situation that involves, or threatens to involve, one or more of the following types of conditions that impact safety or BES reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a cyber security incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.

	associated with TCAs and removable media that require connection to BES cyber assets.
Public Policy Responsiveness	• Comply with requirements under NERC CIP-010 and CIP-003 with respect to the management and control of TCAs and removable media in relation to medium and low impact BES sites.

C. EXPENDITURE PLAN

Table 1 below presents forecasted costs for the Project. Costs are based on historic costs of similar projects.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2024	Total
Capital[1] and Minor Fixed Assets	3.5	3.5	0.0	0.0	0.0	0.0	0.0	7.0
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**3.5**	**3.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**7.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.5**	**3.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**7.0**

[1] Includes Overhead at current rates.

D. ALTERNATIVES

The Project is non-discretionary given its mandatory compliance driver and associated timing pursuant to applicable NERC CIP standards. As such, the only relevant alternatives analysis pertained to the optimal technical solution for ensuring and sustaining compliance.

Alternative 1. Continuing with Short-Term USB Solution

As indicated above, Hydro One began adopting a short-term USB solution in 2017 to meet the immediate NERC compliance obligations for all medium impact BES sites, as well as in anticipation of NERC requirements that will begin to apply to low impact BES sites by the end of 2019. While this USB solution meets the minimum requirement for compliance logging, it relies on manual processes. More specifically, field protection and control personnel log into a portal to download such access logs on a monthly basis. In addition, the USB solution is not capable of capturing complete configuration changes, or integrating with Hydro One's Security Event Management system to support real-time event correlations and alerts for remote or onsite access. Since the USB devices do not have network connectivity, to implement any updates and patches relating to the operating system, application, or anti-virtus signatures, the USBs need to be reimaged and shipped to the appropriate Field Protection and Control technicians, which can take three to four months to complete. Further, the effectivenss of the USB solution is heavily dependent upon field resources' adherence to applicable process and procedures.

Alternative 2. Proposed PAM Solution *(Recommended)*

In parallel with the roll out of the short-term USB solution, the Project is recommended and required in order to ensure and sustain long-term NERC compliance and cyber asset security. The above-mentioned weaknesses and inefficiencies associated with the short-term solution will all be addressed by the proposed PAM solution, which will support two-factor authentication, protected passwords, and a robust and automated audit trail of system access and user actions.

E. EXECUTION RISK AND MITIGATION

The risk to this Project includes scheduling of resources to complete all the necessary work. This risk is mitigated through coordinated planning and scheduling. Estimates for the majority of the applicable sites will be completed in Q1 2019, with the implementation plan slated for execution over 2019 and 2020.

SR-18 PSIT Cyber Equipment Replacement

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Multiple In-Service Dates	**3 Year Test Period Cost ($M):**	13.7
Trigger(s):	Compliance, Strategic, Reliability, Public Policy Responsiveness		
Outcomes:	Compliance with NERC requirements; ensure cyber security of transmission system operation		

A. OVERVIEW

Power System Information Technology ("PSIT") Cyber Equipment Replacement (the "Project") involves the replacement of End of Life ("EOL") cyber security equipment. This equipment protects the network used at the Ontario Grid Control Center to control the operation of transmission system in Ontario. Business and operational demands for managing and maintaining a reliable transmission system increasingly rely on cyber assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data, resulting in increased risks to these cyber assets. As an operator of a Bulk Electric System ("BES"), Hydro One is required to comply with the reliability standards established by the North American Electric Reliability Corporation ("NERC") to ensure the integrity of the interconnected North American BES. NERC Critical Infrastructure Protection ("CIP") Reliability Standards provide a comprehensive set of requirements to protect the BES from malicious cyber-attacks. Responsible entities, such as Hydro One must have minimum security management controls in place to protect critical cyber assets. As such, completing the Project is integral to Hydro One to address evolving cyber threats to ensure ongoing regulatory compliance, reliability and operational effectiveness of the systems controlling the Ontario transmission network and North American BES.

Witness: Lincoln Frost-Hunt

B. NEED AND OUTCOME

Investment Need

Hydro One operates one of the largest transmission systems in North America. Hydro One's transmission system extends to most of the province and operates in diverse geographic and climactic conditions. Hydro One's transmission system is a critical asset for the province, among others, it comprises the BES, which requires compliance with reliability standards established by the NERC to ensure the integrity of the interconnected North American BES. The reliability framework for Ontario's electricity transmission system is based on the reliability standards established by NERC, which have been adopted and are enforced in Ontario by the Independent Electricity System Operator.

The NERC CIP standard provides a cyber-security framework for the identification and protection of critical cyber assets (i.e. devices that use a routable protocol or are dial-up accessible) that control or affect the reliability of North America's bulk power systems. The CIP Cyber Security Standards are mandatory and enforceable across all regulated entities, such as Hydro One. The following CIP Cyber Security Standards applicable to this investment are:

- **CIP-005-1 – Cyber Security – Electronic Security Perimeters:** Requires the identification and protection of an electronic security perimeter and access points. The electronic security perimeter is to encompass the critical cyber assets identified pursuant to the methodology required by CIP-002-1.
- **CIP-007-1 – Cyber Security – Systems Security Management:** Requires a responsible entity to define methods, processes, and procedures for securing the systems identified as critical cyber assets, as well as the non-critical cyber assets within an electronic security perimeter.
- **CIP-008-1 – Cyber Security – Incident Reporting and Response Planning:** Requires a responsible entity to identify, classify, respond to, and report cyber security incidents related to critical cyber assets.

- **CIP-009-1 – Cyber Security – Recovery Plans for Critical Cyber Assets:** Requires the establishment of recovery plans for critical cyber assets using established business continuity and disaster recovery techniques and practices.

The investment is needed to address the EOL cyber security equipment for the PSIT used at Hydro One Control Centers. This technology includes Intrusion Detection/Prevention equipment, Authentication, Authorization, and Accounting technology, Electronic Security Perimeter equipment (firewalls), log collection and retention technology, and cyber vulnerability assessment technology. The Cyber EOL investments, like this Investment, are used to keep technology deployed for security of the grid control infrastructure within support windows of the various technology vendors. Cyber equipment only has a lifespan of 5 years. With fast-paced innovation that responds to an emerging and increasingly aggressive threat landscape, security impacts an asset's life expectancy. Keeping the cyber equipment current is essential to addressing emerging vulnerabilities and maximizing the protection of Hydro One systems and data.

The grid cyber security technology is integrated with the systems that allow operators to remotely control power system equipment on the transmission system. There are two risks associated with failure of this equipment. The main risk of the failure can affect the ability of Hydro One controllers to effect control of transmission system equipment. For example, a firewall failure would not allow the control systems at the control centres to communicate to field equipment. This could prevent a critical control action from being executed when required, and loss of visibility of key power system operating parameters. Another risk is associated with NERC compliance obligations. For example, failure of the logging system could result in loss of historical system logs. NERC CIP standards require that logs for such systems are kept for a minimum of 90 days.

Investment Description

As already stated, the Investment involves the replacement of EOL cyber security equipment for PSIT. This investment is a Project to refresh the cyber security equipment that helps protect, detect, and respond to cyber security threats such as firewalls, authentication managers and identity access management, network visibility and traffic monitoring technology, advanced threat detection and file integrity monitoring, and vulnerability management. Projected life cycle planning is based on a rolling 5-year.

Outcome

The Project will result in regulatory compliance with applicable NERC CIP standards, while ensuring grid reliability and resiliency against cyber security threats to Hydro One's Control Centers which are operating the transmission network.

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's Renewed Regulatory Framework:

Operational Effectiveness	• Maintain the applications and systems controlling the grid to ensure safe, reliable operation of the transmission network.
Public Policy Responsiveness	• Comply with mandatory NERC-CIP requirements.

C. EXPENDITURE PLAN

The Project scoping is currently under development to determine size and scope which will affect the total Project cost. Table 1 below presents forecasted costs for the Project. These costs are based on historical information and anticipated future needs.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	6.7	1.0	5.0	7.7	7.0	3.4	-	30.9
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Gross Investment Cost	**6.7**	**1.0**	**5.0**	**7.7**	**7.0**	**3.4**	-	**30.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Net Investment Cost	**6.7**	**1.0**	**5.0**	**7.7**	**7.0**	**3.4**	-	**30.9**

[1] *Includes Overhead at current rates.*

D. ALTERNATIVES

The Project is non-discretionary and no alternatives have been considered. Failure to address obsolete, unsupported systems will put Hydro One in a position where it will not be able to meet regulatory obligations or provide adequate cyber security protection which would result in non-compliance. In addition, this would result in jeopardizing system reliability by leaving it exposed to cyber security risks. As a result of replacing EOL Cyber Security equipment, the Project will meet regulatory compliance obligations and ensure operational effectiveness of the systems used in the control of the Ontario transmission network.

E. EXECUTION RISK AND MITIGATION

There are no significant risks identified to the completion of this investment.

SR-19 Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures

Start Date:	Q4 2015	**Priority:**	High
In-Service Date:	Q4 2025	**3 Year Test Period Cost ($M):**	298.4
Trigger(s):	Strategic, System Renewal		
Outcomes:	Improve system reliability, minimize customer outages, reduce maintenance costs associated with the EOL assets, realize cost savings and efficiencies as a result of bundling needed work within this investment		

A. OVERVIEW

This set of Transmission Line Refurbishment Projects involve the replacement of all End-Of-Life ("EOL") components along all or part of a line section. These projects are driven by the need to replace major transmission line components, verified to be at EOL by condition assessment, including Aluminum Conductor Steel Reinforced ("ACSR") conductor, obsolete copper conductor, or deteriorated structures in high risk condition.

These assets pose safety and system reliability risks should they fail. In addition, copper conductors are the oldest type of overhead conductors in the Hydro One transmission system and are now obsolete. Hydro One is no longer able to mend some broken copper conductors due to this obsolescence. These Line Refurbishment Projects aim to remove and replace these deteriorated EOL conductors, or refurbish high risk structures to sustain safe and reliable delivery of electricity. Hydro One has evaluated various alternatives for these Projects, as described below, and concluded that replacing the EOL deteriorated ACSR, obsolete copper conductors, or refurbishing deteriorated structures is the most cost effective and efficient undertaking for sustaining these assets. The projected cost of these Projects is estimated to be $298.4 million over the 2020-2022 test period.

B NEED AND OUTCOME

Investment Need

Long transmission circuits are required to deliver power across Hydro One's vast territory. These transmission assets are exposed to environmental stresses, including severe weather and temperature variations that degrade equipment over time.

Hydro One has approximately 29,000 circuit kilometres of high-voltage transmission conductors. Over 99% of Hydro One's transmission system is comprised of overhead power lines. The conductor of an overhead transmission line is the single largest and most vulnerable component. Close to 98% of Hydro One's overhead conductor fleet utilizes ACSR conductors, with copper, aluminum, and aluminum conductor steel supported ("ACSS") types making up the balance.

Hydro One defines Expected Service Life ("ESL") as the average age in years that an asset can be expected to operate under normal system conditions. Hydro One also defines End of Life ("EOL") as the state of having a high likelihood of failure, or loss of an asset's ability to provide the intended functionality. EOL state is established only through testing, where an asset is empirically verified to have deteriorated to a point where its ability to perform is compromised. A conductor in a deteriorated condition translates to a loss of mechanical strength or ductility, resulting in the conductor possessing a greater likelihood of breaking and dropping. EOL is always determined by condition assessment.

Hydro One uses an ESL of 90 years for overhead transmission conductors, although the life span of each conductor can vary between 50 and 120 years, as numerous uncontrollable variables affect conductor deterioration, including manufacturing material quality, location, orientation, local atmospheric pollution levels, weather cycles and stringing tension. Currently, about 5% of the overhead conductor fleet has reached or exceeded their ESL of 90 years.

Table 1 below summarizes the demographic profile of the overhead conductor fleet. Without any further replacements, the percentage of conductors exceeding ESL will increase to 13% by end of 2024.

Table 1 - Overhead Conductor Demographics

Conductor Type	Circuit km in Service	Average Age (Years)	ESL (Years)	Beyond ESL	Beyond ESL 2024	Beyond ESL 2029
ACSR	28,437	54	90	876	3,125	3,988
Copper	512	97	70	512	512	512
Aluminum	21	89	100	0	15	15
ACSS	137	26	N/A*	0	0	0
Total	**29,107**	**55**		**1,389**	**3,653**	**4,516**

** Relatively new conductor type to Hydro One, limited installation, ESL to be established*

Hydro One operates a condition assessment program to determine the condition of conductors that are beyond 50 years of age. Presently, condition assessment results indicate that about 3,680 km, or 13% of the conductor fleet is known to be at high risk as outlined in Figure 1. This includes lines with ACSR conductors and structures verified to be in high risk condition through testing, and copper conductors, many of which suffer from damage caused by lightning strikes, mechanical strength loss and can no longer be repaired due to obsolete repair components.

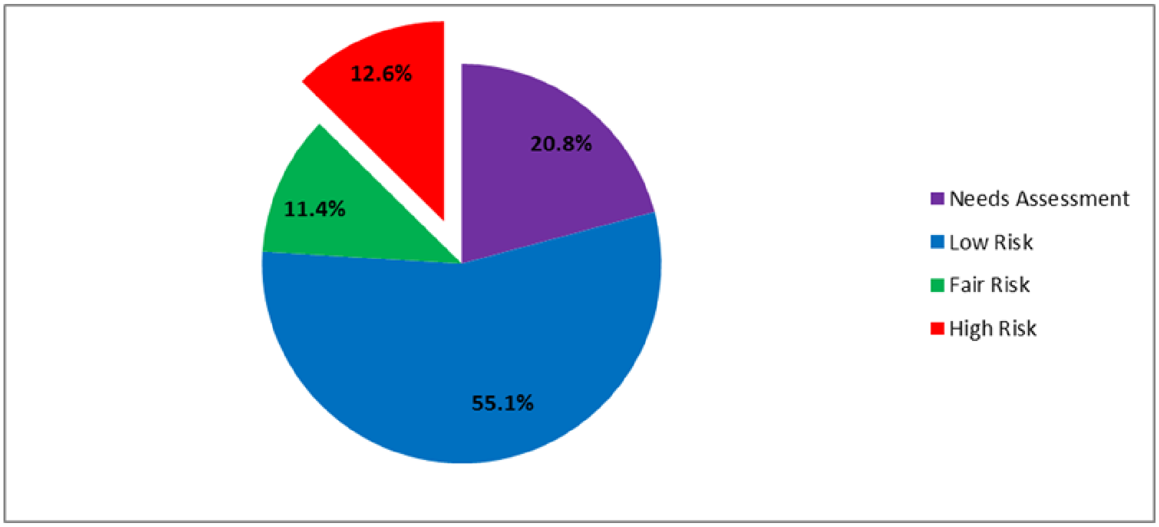


Figure 1 - Distribution of Overhead Conductor Condition

ACSR conductors consist of aluminum strands that surround galvanized steel strands, referred to as the core. Once the galvanized coating of the core wears off, for example as a result of weather or strand movement, the exposed steel strands corrode quickly, resulting in a loss of tensile strength or ductility. Deterioration of tensile strength results in a failure to hold required loads, while deterioration in ductility, makes the conductor brittle, making the suspended conductor which is moved by wind forces susceptible to cracking and breaking, as shown in Figure 2.

Figure 2 - Broken ACSR Conductor

Less than 2% of Hydro One conductor fleet is Copper conductor. Copper conductors are the oldest conductor type Hydro One has in its Network. Although copper conductors are not as susceptible to deterioration from corrosion when compared to ACSR conductors, this type of conductor has been exposed to the elements for a much longer time and many suffer from damage caused by lightning strikes. Figure 3 illustrates a dissected Hydro One copper conductor revealing a plant fibre core. This conductor type cannot be spliced and therefore its failure would result in the need to replace an entire dead-end to dead-end span, needing extensive resources and financing to perform on an unplanned emergency basis.

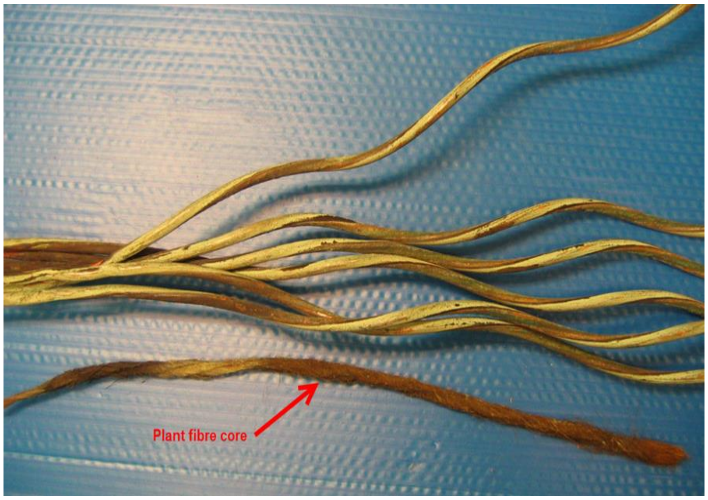


Figure 3 - Dissected copper conductor

The breaking of a conductor will lead to the overhead suspended conductor dropping, potentially along with its hardware as shown in Figure 4 below. A broken and dropped conductor will result in an outage to the circuit and endangers all in proximity of its fall. A typical transmission line spans 300 m at a rough height of 30 meters. At about 1.6 kg/m, a falling conductor span is equivalent to a 480 kg metallic mass falling from 30 m above. Potential damage as a result of this fall is demonstrated in Figure 5 below. In some cases a broken conductor can remain energized, which presents an added danger of electrocution and fire hazard to its surroundings.

Figure 4 - Fallen span of conductor

Figure 5 - Damage from a fallen conductor

Figure 5 shows a fallen conductor as a result of an insulator failure. Although the cause of this conductor dropping was not the breakage of the actual conductor, the result would be the same.

Line refurbishment projects are triggered by a confirmed need to replace the conductor or in a minority of cases, extensive structure deterioration, along a line section. This confirmation comes empirically through testing which confirms a deteriorated condition of the conductor or structure. Work plans to perform the replacement of EOL conductors or refurbishment of structures also consider the replacement or refurbishment of all other line components. As such, a conductor replacement project frequently includes the refurbishment of all major components within that line section, based on an assessment of the line's structures, shieldwire, insulators and hardware.

During the development of a line refurbishment project, the line section targeted for conductor replacement is surveyed, at which point other assets that are at EOL or near EOL are identified and also targeted for replacement. Components in good condition are not refurbished or replaced. Bundling conductor replacement with the replacement or refurbishment of other components is cost effective.

Presently, the Hydro One overhead transmission system has 3,680 km of conductor known to be in high risk condition, as verified empirically through condition assessment. Of this set of identified high risk conductors, 859 km, or 23% of the known high risk population have been planned and packaged into refurbishment projects that address conductors confirmed to be in EOL condition during the planning period. Confirmed EOL lines, as opposed to confirmed Near EOL lines, have deteriorated further, and therefore present the greatest risk of failure.

Investment Description

Table 2, Table 3, Table 4, and Table 5 present the set of material projects that aim to completely refurbish the listed sections of the circuits. Hydro One has confirmed, through condition assessment that these line sections have deteriorated to the extent that their conductor or structure has reached EOL and, as such, require replacement or refurbishment.

The project list below also includes a “placeholder” line item that allocates funding for packaging an additional 456 km, or 12% of verified high risk conductors in addition to the planned and packaged 859 km of EOL projects. This is intended to reserve funding for conductors that are confirmed to be at EOL but are still undergoing the planning process. As an example, some of these projects are under review by Hydro One System Development group to verify whether a sustainment based project is the most appropriate approach to address the short and long term system requirements. The projected cost for forecast projects are based on a historical average cost for line refurbishment projects which is being used for planning purposes prior to formal project estimation.

Each project will entail an assessment of all assets along the line section and the replacement or refurbishment of all components that are deemed at or near EOL. These components might include shieldwire, insulators or hardware, to comprehensively renew the line as a whole. In addition, all structures and foundations will be refurbished as required.

Bundling conductor replacement with the replacement/refurbishment of other components is cost effective. Bundled work does not mean replacing assets that are in good condition. The development of a line refurbishment project, through budgetary and detailed estimation stages, which collectively average 18 months, is used to identify which other assets have also limited service life and can benefit from replacement, while work crews are already deployed to replace the conductor.

1 **Table 2 - Line Refurbishment Projects Driven by EOL ACSR Conductors**

Project	Circuit km of Project during planning period
B5/6C, BurlingtonTS X WestoverCTS, Tx Line Refurb.	0 (project in-execution, majority replaced prior to 2020)
D2L, Upper Notch JCT X Martin River JCT, Line Refurb.	0 (project in-execution, majority replaced prior to 2020)
E1C, Ear Falls TS X Slate Falls DS + Etruscan JCT X Crow River DS, Line Refurb.	162
H1L/H3L/H6LC/H8LC, Bloor Street JCT X Leaside 34 JCT, Line Refurb.	8
D6, Des Joachims JCT X Tee Lake JCT + Chalk River JCT X Petawawa JCT, Line Refurb.	77

2

3 **Table 3 - Line Refurbishment Projects Driven by Obsolete Copper Conductors**

Project	Circuit km of Project during planning period
D3A, Allanburg TS X AWS Steel CTS, Tx Line Refurb.	0 (project in-execution, majority replaced prior to 2020)
B3/B4, Horning Mountain JCT X Glanford JCT, Tx Line Refurb.	22
A8K/A9K, Str. 141 JCT X Kirkland Lake TS, Tx Line Refurb.	112
A7L/R1LB & 57M1, Alexander B JCT X Lakehead TS & Nipigon JCT, Tx Line Refurb.	227
K1/K2, Kirkland Lake TS X Holloway Holt JCT, Tx Line Refurb.	14
D2/3H & D4 & D6T, Hunta SS X Abitibi Canyon SS, Tx Line Refurb.	183
Q2AH, Rosedene JCT X St.Anns JCT, Tx Line Refurb.	22

Table 4 - Line Refurbishments Project Driven by Deteriorated Structures

Project	Circuit km of Project during planning period
N21W/N22W, Sarnia Scott TS X Buchanan TS, Tx Str. Refurb.	0 (no conductor replaced)

Table 5 - Forecast for Expected Line Refurbishment Need Discoveries

Project	Circuit km of Project during planning period
Tx Line Refurb: Placeholder, Expected EoL Line Discoveries	456

Outcome

The following table presents anticipated benefits as a result of the aforementioned Projects in accordance with the OEB's Renewed Regulatory Framework:

Customer Focus	• Replacement of EOL conductors decreases the likelihood of their failure. Decreased likelihood of conductor failure results in a decreased likelihood of an outage to the customer.
Operational Effectiveness	• Operating a circuit with EOL conductors subjects that circuit to an increased likelihood of failure, which directly threatens reliable operation of the system. Line refurbishment will alleviate this threat.
Public Policy Responsiveness	• Decreased likelihood of failure reduces the likelihood of a conductor dropping and potentially causing injury to public or employees, damaging property or damaging local environment (fire caused by dropped energized conductor)
Financial Performance	• Realize cost savings by bundling conductor replacement with associated deteriorated line components as part of the same project.

C. EXPENDITURE PLAN

As discussed above, Line Refurbishment Projects are needed to replace/refurbish the EOL ACSR conductors, obsolete copper conductors and line sections with deteriorated structures, in order to mitigate the risk to safety and reliability that would result from their failure. Hydro One planned these projects in a way that strives to complete it as effectively and efficiently as possible to minimize the cost of performing this sustainment need.

Table 6 summarizes historical and projected spending on the aggregate. The “Previous Years” costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year. Likewise, the costs noted in “Forecast 2025+” are project costs forecast beyond 2024.

Table 6 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	175.1	88.7	131.7	102.3	55.1	81.8	0.0	634.7
Less Removals	17.0	6.9	9.6	7.8	4.1	5.9	0.0	51.3
Gross Investment Cost	**158.1**	**81.8**	**122.1**	**94.5**	**51.0**	**75.9**	**0.0**	**583.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**158.1**	**81.8**	**122.1**	**94.5**	**51.0**	**75.9**	**0.0**	**583.4**

[1] Includes overhead at current rates.

Table 7 presents test year costs for individual projects and presents the total cost for EOL ACSR, obsolete copper and deteriorated structure driven line refurbishment projects. The total cost includes costs incurred in previous years and forecasted beyond 2024, where applicable.

Table 7 - Detailed Project Costs

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
N21W/N22W, Sarnia Scott TS-Buchanan TS, Str. Refurb.	5.1	0.0	0.0	0.0	0.0	5.1	27.7	2019
D3A, Allanburg TS X AWS Steel CTS, Tx Line Refurb.	2.7	0.0	0.0	0.0	0.0	2.7	13.6	2020
B5/6C, BurlingtonTS X WestoverCTS, Tx Line Refurb.	5.5	0.0	0.0	0.0	0.0	5.5	22.9	2020
Line Refurbishment - D2L, Upper Notch JCT x Martin River JCT	3.0	0.0	0.0	0.0	0.0	3.0	28.3	2019
Tx Line Refurb: Placeholder, Expected EoL Line Discoveries	2.7	46.6	48.2	37.3	75.6	210.5	213.1	2025
Tx Line Refurb. B3/B4 | Horning Mountain JCT-Glanford JCT (Copper)	3.5	0.0	0.0	0.0	0.0	3.5	20.6	2020
Tx Line Refurb. A8K/A9K | A8K Str. 141 JCT-A8K Str. 277 JCT-Ramore JCT (Copper)	13.3	10.7	0.0	0.0	0.0	24.1	38.4	2021
Tx Line Refurb. A7L/R1LB & 57M1 Alexander B JCT-Lakehead TS & Nipigon JCT Copper	20.4	20.9	14.3	0.0	0.0	55.6	76.9	2022
Tx Line Refurb. K1/K2 | Kirkland Lake TS-Holloway Holt JCT (Copper)	3.2	0.0	0.0	0.0	0.0	3.2	6.5	2020

Tx Line Refurb. E1C | Ear Falls TS-Slate Falls DS (EoL) + Etruscan JCT-Crow River DS (Near EoL)	2.2	15.3	15.9	13.7	0.3	47.4	52.0	2024
Tx Line Refurb. H1L/H3L/H6LC/H8LC | Bloor Street JCT-Leaside 34 JCT (EoL)	1.6	10.4	5.5	0.0	0.0	17.5	17.6	2022
Tx Line Refurb. D2/3H & D4 & D6T, Hunta SS X Abitibi Canyon SS (EoL)	9.5	9.7	7.6	0.0	0.0	26.9	36.0	2022
Tx Line Refurb. D6 | Des Joachims JCT X Tee Lake JCT + Chalk River JCT X Petawawa JCT (Close EoL)	8.6	3.7	0.0	0.0	0.0	12.3	21.7	2021
Q2AH, ROSEDENE JCT X ST.ANNS JCT, Tx Line Refurb	0.4	4.8	2.9	0.0	0.0	8.1	8.1	2022
Net Investment Cost	**81.8**	**122.1**	**94.5**	**51.0**	**75.9**	**425.3**	**583.4**	

Witness: Donna Jablonsky

As shown in Figure 1, demographics for Hydro One overhead conductors demographics that have reached and exceeded EOL is increasing, thereby necessitating the replacement of those deteriorated EOL conductors. Line refurbishment investments are increasing over the test year period as compared to historical years which reflects the increase in circuit kilometres that are being replaced.

The following factors also influence the costs of Line Refurbishment Projects:

- The circuit voltage level, site accessibility, structure type (wood pole vs. steel structure);
- The length of conductor being replaced;
- Whether replacement of deteriorated shieldwire, insulators, or additional hardware is required; and
- Any structure or foundation work required.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: The “Do Nothing” - Reactive Replacement involves waiting for deteriorated conductors to fail before replacing them on a reactive basis. This alternative has been rejected since a failed conductor will immediately lead to a circuit outage requiring emergency restoration. Replacement of conductors on an emergency basis will require constant reprioritization of planned work and lead to inefficient deployment of resources. Reactive conductor replacements would also prolong circuit outages and may therefore extend equipment and customer outages.

Alternative 2: Replacements based on Risk Mitigation Assessments is a preferred undertaking. It involves proactively replacing/refurbishing EOL ACSR conductors, obsolete copper conductors and deteriorated structures based on risk mitigation assessments. The risk mitigation assessment allows Hydro One to replace High Risk assets in a way that mitigates safety and reliability risks while balancing the asset needs, resource availability and the cost impact to customers. This alternative has been selected as a preferred undertaking as it reduces the number of customer outages and allows taking advantage of planned customer outages to perform the necessary conductor replacements. Furthermore, with a planned outage, a customer can be temporarily connected to an alternative supply in order to avoid any unforeseen interruptions as a result of the outage. It further allows Hydro One to bundle all the necessary work in a particular geographic area in order to maximize the productivity of a deployed work crew. This is especially relevant in remote areas, where access is extremely difficult.

E. EXECUTION RISK AND MITIGATION

Risks to these projects include: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges or regulatory approvals. A thorough risk assessment workshop is performed during the project planning phase where all known risks are identified and mitigation plan is developed. For example, to address outage constraints, Hydro One develops an outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize to a minimum the loss of supply to the customer. The plan might include switching a customer to an alternative supply, the construction of a temporary by-passing circuit or supply of portable generation that will maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer’s planned maintenance driven outages. Another example is the involvement of real estate from the project inception. It allows for the early identification of real estate issues, such as missing or inadequate land rights. Once the issue is identified, Hydro One tries to resolve it prior to execution of the project.

SR-20 Transmission Line Refurbishment - Near End of Life ACSR Conductor

Start Date:	Q4 2016	**Priority:**	Medium
In-Service Date:	Q4 2026	**3 Year Test Period Cost ($M):**	237.3
Trigger(s): Strategic, System Renewal			
Outcomes: Improve system reliability, minimize customer outages, reduce maintenance costs associated with the High Risk assets, realize cost savings and efficiencies as a result of bundling needed work within this investment			

A. OVERVIEW

Near End-of-Life Transmission Line Refurbishment Projects (the "Projects") involves the proactive replacement of the Aluminum Conductor Steel Reinforced ("ACSR") conductors that are confirmed, through condition assessments, to be in a deteriorated condition and approaching End-Of-Life ("EOL"). The near EOL conductors are assets whose condition is expected to be in a state requiring removal from service in the near future. Over the test period, there is large population of overhead ACSR conductor that will reach or exceed their Expected Service Life ("ESL") and therefore the probability of their failure is increasing as a result of their aggregate increase in deteriorated condition. This conclusion is supported through mathematical modelling completed by a third party expert, Electric Power Research Institute ("EPRI").

EPRI developed a conductor hazard curve and applied it to forecast the amount in kilometres of ACSR overhead transmission conductor expected to be in high risk condition (i.e. EOL or near EOL). The EPRI report forecasts that 3,920 circuit km of the ACSR conductor fleet will be at EOL or near EOL condition by 2024.[1] This forecast of ACSR conductor condition aligns with the fact that by the end of 2024, about 13% or 3,653 circuit km of the overall conductor fleet will reach or exceed their ESL without further replacements.

[1] TSP Section 1.4 Attachment 4 - Derivation of Overhead Conductor Hazard Function, section 5-3, p 93.

Hydro One plans to replace 812 of circuit kilometres of near EOL ACSR conductor in order to manage the safety and system reliability risks associated with the forecasted increasing volume of conductors in High Risk condition. Hydro One has evaluated various alternatives for the Project, as described below, and concluded that replacing near EOL ACSR conductors is the most prudent and cost effective undertaking. The estimated cost of these near EOL Line Refurbishments projects total an estimated $237.3 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

Hydro One is striving to maintain the reliability of its transmission network while controlling maintenance, repair and replacement costs. Aging equipment, more stringent operating requirements, financial constraints and retiring expertise have made the management of transmission line assets increasingly challenging. To address these challenges, Hydro One is reviewing its maintenance and replacement practices to ensure that they are underpinned by sound evidence. This includes the use of condition and risked-based maintenance and replacement scheduling using advanced analytics-based techniques. Understanding the condition and remaining life of conductors help Hydro One to make better decisions about conductor maintenance, repair, and replacement.

As part of this asset management effort, Hydro One asked EPRI to investigate Hydro One overhead transmission line conductor demographic and condition data and to determine what insights could be obtained to support asset management decisions. EPRI has developed a methodology using advanced statistical techniques for analyzing conductor historical replacements and assessments and applied it to the Hydro One overhead ACSR transmission conductor fleet. Hydro One provided in-service, removed-from-service and condition assessment data for its overhead ACSR transmission conductor fleet. Using this data, EPRI developed a mathematical model relating ACSR conductor age to the probability that an ACSR conductor would be in high risk condition. The model, along with demographic information about the present fleet, was used to forecast the amount in kilometres of ACSR conductors expected to be in high risk condition (i.e. EOL and near EOL) over the next five, ten and twenty-year periods.

The Hydro One transmission system has approximately 29,000 circuit kilometers of high-voltage transmission conductors with close to 98% being ACSR type of conductors. Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions. Hydro One also defines EOL as the state of having a high likelihood of failure, or loss of an asset's ability to provide the intended functionality.

Based on the analysis and modeling performed by EPRI, ACSR conductors reach ESL at about the age of 90 years. As EPRI stated in its report, unless there is some dramatic change in the stressors leading to degradation (e.g. loading), it is reasonable to expect future performance to continue to fit this age-related model. Comparing this age-dependent hazard curve model with the ages of the in-service conductor lengths can provide an estimate of the conductor lengths that would be in high risk condition (based on historical criteria) in future years.

Table 1 below provides EPRI cumulative estimates of ACSR circuit-km expected to be in high risk condition (i.e. EOL and near EOL) within the next five, ten and twenty-year periods.

Table 1 - Mean Values for the 5, 10, and 20 year projection (from 2018)[2]

Life Event Modeled	Input Data	Projection Means (and 95% Confidence Bands) in km		
		5 Years (2023)	**10 Years (2028)**	**20 Years (2028)**
Reaching EOL Or near EOL condition	Condition assessment data	3,273 (2,552, 4,123)	6,467 (5,182, 7,867)	12,366 (10,468, 14,134)

Table 1 contains information from the projection model. It shows that the amount of circuit kilometers of conductors expected to be in high risk condition over the next twenty years is about 42% of the fleet. As such, it is prudent for Hydro One to proactively engage in conductor replacement, so to ensure that the collective High Risk conductor assets are managed in a timely manner that maintains system reliability and limits the safety risks. Failure to address the issue proactively would result in unmanageable risk and Hydro One will be in a position where it would not be feasible, even impossible, to manage the set of cumulative assets deteriorated to EOL condition.

Investment Description

As described above, EPRI developed a ACSR conductor hazard curve and applied it to forecast the amount in kilometers of ACSR overhead transmission conductor expected to be in high risk condition (i.e. EOL and near EOL). As part of the Project, Hydro One intends to replace approximately 812 circuit km, or 22% of the known high risk population of conductor in order to manage the safety and system reliability risks associated with confirmed near EOL conductors over the next five years.

The individual near EOL line refurbishment projects are presented in Table 2 below. Each project will entail an assessment of all assets along the line section and the replacement/refurbishment of all components that are deemed at or near EOL. These

[2] TSP Section 1.4 Attachment 4 - Derivation of Overhead Conductor Hazard Function, section 5-4, p 94.

components might include shieldwire, insulators and hardware, to comprehensively renew the line as a whole. In addition, all structures and foundations will be assessed and refurbished or replaced as required.

These projects will address this prioritized set of 812 circuit km of existing confirmed near EOL conductors. Line refurbishment prioritization will help with the pacing of the high risk conductor replacements over the longer periods (i.e. over the next 10 or 20 years) and also will allow to better manage the required capital expenditures associated with conductor replacement projects.

Table 2 - ACSR Conductor Near EOL Replacement Projects

Project	Circuit km of Project during planning period
B23C, Pancake JCT X Oshawa Area JCT, Tx Line Refurb.	120
C28C, Chats Falls SS X Cherrywood TS, Tx Line Refurb.	0 (in-servicing beyond planning period)
C27P, Galetta JCT X Bannockburn JCT, Tx Line Refurb.	128
L22H, Easton JCT X Hinchinbrk N JCT, Tx Line Refurb.	65
E8V/E9V, Orangeville TS X Essa JCT, Tx Line Refurb.	112
M6E/M7E, Cooper's Falls JCT X Orillia TS, Tx Line Refurb.	50
D1M/D2M/D3M/D4M, Otter Creek JCT X Minden TS, Tx Line Refurb.	0 (in-servicing beyond planning period)
A4H/A5H, C.P. Tunis JCT X Fournier JCT, Tx Line Refurb.	47
B5QK, Barrett Chute #2 JCT X Sharbot JCT, Tx Line Refurb.	60
A4L, Roxmark Mines CTS X Beardmore JCT/DS #2, Tx Line Refurb.	78

T61S, Timmins JCT X Shiningtree JCT, Tx Line Refurb.	115
N5K, Sarnia Scott TS X Kent TS, Tx Line Refurb.	0 (in-servicing beyond planning period)

Outcome Summary

The following table presents anticipated benefits as a result of the aforementioned Projects in accordance with the OEB's Renewed Regulatory Framework:

Customer Focus	• Replacement of Near EOL conductors manages the population of High Risk condition conductors, which ultimately mitigates the risk of their failure. Decreased likelihood of conductor failure results in a decreased likelihood of an outage to the customer.
Operational Effectiveness	• Operating a circuit with near EOL conductors subjects that circuit to an increased likelihood of failure, which threatens reliable operation of the system. Line refurbishment will alleviate this threat.
Public Policy Responsiveness	• Decreased likelihood of failure reduces the likelihood of a conductor dropping and potentially causing injury to public or employees, damaging property or damaging local environment (fire caused by dropped energized conductor)
Financial Performance	• Realize cost savings by bundling conductor replacement with associated deteriorated line components as part of the same project.

C. EXPENDITURE PLAN

As discussed above, Line Refurbishment projects are needed to replace condition verified near EOL ACSR transmission overhead conductors over the next five years to manage the increasing population of conductors in High Risk condition. Hydro One planned these projects in a way that strives to complete it as effectively and efficiently as possible so to minimize the cost of performing this sustainment need.

Since the Project consists of a multiple projects, as presented in Table 2 above, Table 3 below consolidates all the costs for individual material projects and presents the total cost for this set of Projects. The "Previous Years" costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024. Table 3 summarizes historical and projected spending on the aggregate.

Table 3 - Total Investment Cost

($ Millions)	**Prev. Years**	**2020**	**2021**	**2022**	**2023**	**2024**	**Forecast 2025+**	**Total**
Capital[1] and Minor Fixed Assets	15.0	67.6	68.9	121.4	128.0	149.7	143.2	693.9
Less Removals	1.2	5.4	5.5	9.7	10.2	12.0	11.5	55.5
Gross Investment Cost	**13.8**	**62.2**	**63.4**	**111.7**	**117.8**	**137.7**	**131.8**	**638.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**13.8**	**62.2**	**63.4**	**111.7**	**117.8**	**137.7**	**131.8**	**638.4**

[1] *Includes overhead at current rates.*

Table 4 below presents the projected costs on an individual project basis. It also provides the total cost, which includes costs incurred in previous years and forecasted beyond 2024, where applicable, for each individual project along with the proposed in-service date.

Table 4 - Detailed Project Costs

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
B23C, Pancake JCT-Oshawa Area JCT, Tx Line Refurb.	0.0	0.0	2.0	4.9	19.5	26.4	26.4	2025
Tx Line Refurb. C28C, Complete Line, Chats Falls SS X Cherrywood TS Near EoL	0.0	0.6	3.4	44.7	45.7	94.4	153.9	2026
Tx Line Refurb. C27P | Galetta JCT-Bannockburn JCT (Near EoL)	32.7	28.7	17.5	0.0	0.0	78.9	79.5	2022
Tx Line Refurb. L22H Easton JCT-Hinchinbrk N JCT Near EoL	0.5	7.6	11.7	11.9	10.1	41.9	41.9	2024
Tx Line Refurb. E8V/E9V | Orangeville TS-Essa JCT (Near EoL)	0.0	2.0	15.7	18.5	18.6	54.7	54.7	2024
Tx Line Refurb. M6E/M7E | Cooper's Falls JCT-Orillia TS (Near EoL)	0.0	2.0	22.5	0.0	0.0	24.5	24.7	2022
Tx Line Refurb. D1M/D2M/D3M/D4M | Otter Creek JCT-Minden TS (Close EoL)	0.0	0.0	3.8	9.5	34.1	47.4	115.5	2026
Tx Line Refurb. A4H/A5H | C.P. Tunis JCT-Fournier JCT (Close EoL)	0.0	2.0	16.4	0.0	0.0	18.4	18.7	2022

Tx Line Refurb. B5QK | Barrett Chute #2 JCT-Sharbot JCT (Near EoL)	0.0	2.0	14.7	14.6	0.0	31.3	31.3	2023
Tx Line Refurb. A4L | Roxmark Mines CTS-Beardmore JCT/DS #2 (Near EoL)	9.5	4.9	0.0	0.0	0.0	14.4	22.0	2021
Tx Line Refurb. T2R/T61S | Timmins JCT-Wawaitin JCT-Shiningtree JCT (Close EoL)	19.5	12.7	0.0	0.0	0.0	32.1	37.0	2021
N5K, Sarnia Scott TS X Kent TS, Tx Line Refurb.	0.1	1.0	3.9	13.6	9.7	28.3	32.8	2025
Net Investment Cost	**62.2**	**63.4**	**111.7**	**117.8**	**137.7**	**492.8**	**638.4**	

Witness: Donna Jablonsky

As shown in Table 1 Hydro One overhead conductors are forecasted to be in High Risk condition is increasing. Line refurbishment investments are therefore increasing over the test year period as compared to historical years to manage this.

The following factors influence the costs of Line Refurbishment Projects:

- The circuit voltage level, site accessibility, structure type (wood pole vs. steel structure)
- The length of conductor being replaced;
- Whether replacement of deteriorated shieldwire, insulators, or additional hardware is required;
- Any structure or foundation work required.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: the "Do Nothing" alternative involves waiting for identified near EOL ACSR conductors to deteriorate EOL. This alternative has been rejected since it does not address the main purpose of this investment, to address the issue of a large volume of conductors approaching their EOL, thereby necessitating their proactive replacement. Furthermore, the time at which a conductor deteriorates to become EOL from near EOL is not predictable, and without continuous monitoring cannot be identified. Continuous testing to identify the point at which the condition of conductors reaches EOL would require additional funding and resources.

Alternative 2: Proactive Replacements of near EOL Conductors is the preferred undertaking as it will provide Hydro One with the ability to manage the large population of conductors in High Risk condition over the test period.

E. EXECUTION RISK AND MITIGATION

Risks to these projects include: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges or regulatory approvals. A thorough risk assessment workshop is performed during the project planning phase where all known risks are identified and mitigation plan is developed. For example, to address outage constraints, Hydro One develops an outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize to a minimum the loss of supply to the customer. The plan might include switching a customer to an alternative supply, the construction of a temporary by-passing circuit or supply of portable generation that will maintain supply to the customer. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. Another example is the involvement of real estate from the project inception. It allows for the early identification of real estate issues, such as missing or inadequate land rights. Once the issue is identified, Hydro One tries to resolve it prior to execution of the project.

SR-21 Wood Pole Structure Replacements

Start Date:	Q1 2020	**Priority:**	High
In-Service Date:	Ongoing Program	**3 Year Test Period Cost ($M):**	156.1
Trigger(s):	System Renewal, Safety, Reliability, Environment		
Outcomes	Maintains system reliability by preventing wood pole failures; prevents poles from collapsing and potentially causing public injuries or fatalities; reduce emergency restoration frequency and costs through proactive replacement		

A. OVERVIEW

Wood Pole Structure Replacement Program (the "Program") involves the replacement of the wood poles that have failed condition assessment. Typically, a wood pole fails a condition assessment due to being rotten and being at the end of its service life. Although failures in this population can occur at any time, the likelihood increases during severe weather events. Therefore, the objective is to clear the existing backlog of high-risk structures by 2024. Furthermore, as a result of the Program, Hydro One will be able to maintain system reliability, and reduce safety risk to its employees and the public associated with failing structures. The Program targets the replacement of approximately 800 wood poles each year, totalling 4000 wood poles over the five year planning period. Hydro One has evaluated various alternatives for the Program, as described below and concluded that the most cost effective and efficient undertaking is to proactively replace end of service life wood poles. The projected costs of the Program are estimated to be $156.1 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

Wood poles elevate transmission lines above the ground, providing clearance from ground objects and separation between the circuit conductors and other line components. These structures have various designs, sizes and configurations and support transmission circuits from 115 kV to 230 kV. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access.

Hydro One Transmission currently owns and manages approximately 42,000 wood pole structures spanning about 7,000 kilometers. As presented in Table 1 below, the average age of the wood pole fleet is currently 41 years and 34% of the wood poles are beyond their expected service life of 50 years.

Table 1 - Wood Pole Structure Demographics

Wood Structure	Quantity	Average Age	ESL (Years)	Beyond ESL currently	Beyond ESL 2024	Beyond ESL 2029
Total	42,000	41	50	14,400	15,100	17,940

Wood structures deteriorate over time. The rate of deterioration depends on many factors including location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location. Due to the nature of the design, the wood cross-arm tends to be the weak link and is typically the primary cause of failure.

Wood poles are deemed to be End of Life when the surface condition degrades and the poles are no longer climbable; there is significant surface and pole top rot; or where wood pecker holes have weakened the strength of the pole. Poles that are drilled and have 2.5 inches or less of solid circumferential wood remaining from internal rot will be replaced as they have fallen below their required design strength. All wood poles and components are to be replaced when their condition has deteriorated to a point where there is a significant risk of failure under adverse weather conditions. Based on wood pole assessments, 13% of Hydro One's wood pole population requires replacement, as outlined in Figure 1 below. These poor condition poles typically exhibit woodpecker damage, mechanical damage or insect damage. Approximately 45% of the wood pole population needs to be assessed to determine its condition, while about 42% of the population is either in good condition or not eligible for assessment (these poles are under 25 years old and therefore they do not currently meet the criteria for assessment).

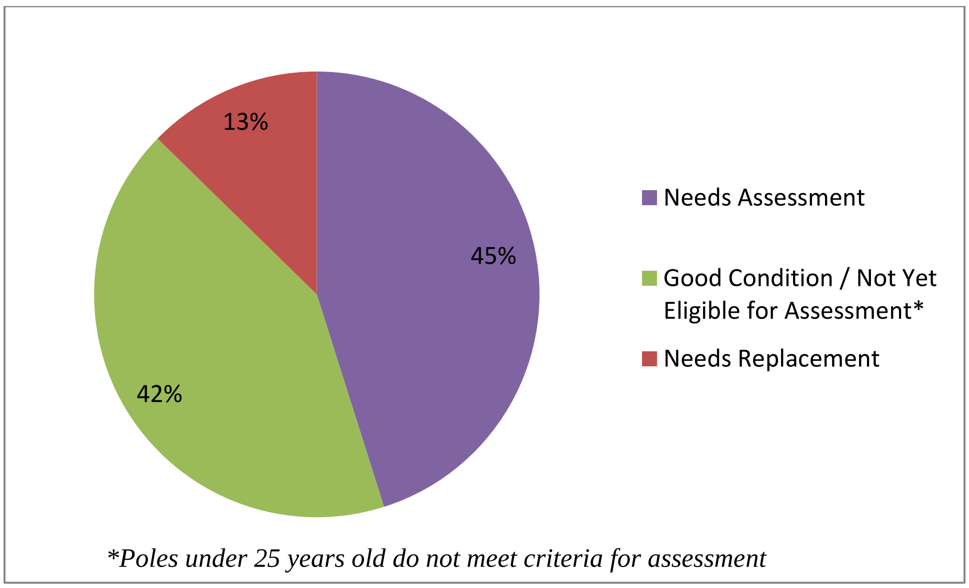


Figure 1 - Wood Pole Fleet Condition Status

The majority of transmission wood pole structures are located in Northern Ontario and many of these structures support radial circuits. As a result, a wood pole or cross-arm failure can often directly result in a customer outage. Many of these northern wood pole circuits feed major industrial customers, who may be forced to shut down until power is restored. Such an event can add significant cost to a customer's operations. Moreover, these Northern circuits supply electricity to local distribution companies in Indigenous communities, which would be adversely affected by any supply interruption.

Figure 2 illustrates a failure of a wood pole. Figure 3 illustrates rotten pole tops that could fail imminently.

Figure 2 - Downed wood pole on circuit M1T

Figure 3 - Rotten pole tops on M1T that could fail imminently

The number of forced outages due to wood pole structure failures has increased over the past ten years, as illustrated in Figure 4. Wood pole failure is the result of a combination of multiple factors such as pole condition, weather condition, physical loading on the pole, and the environment of pole location. Wood poles are a natural product that despite treatment, have some quality inconsistencies in each pole, which can result in an unpredictable failure under certain conditions.

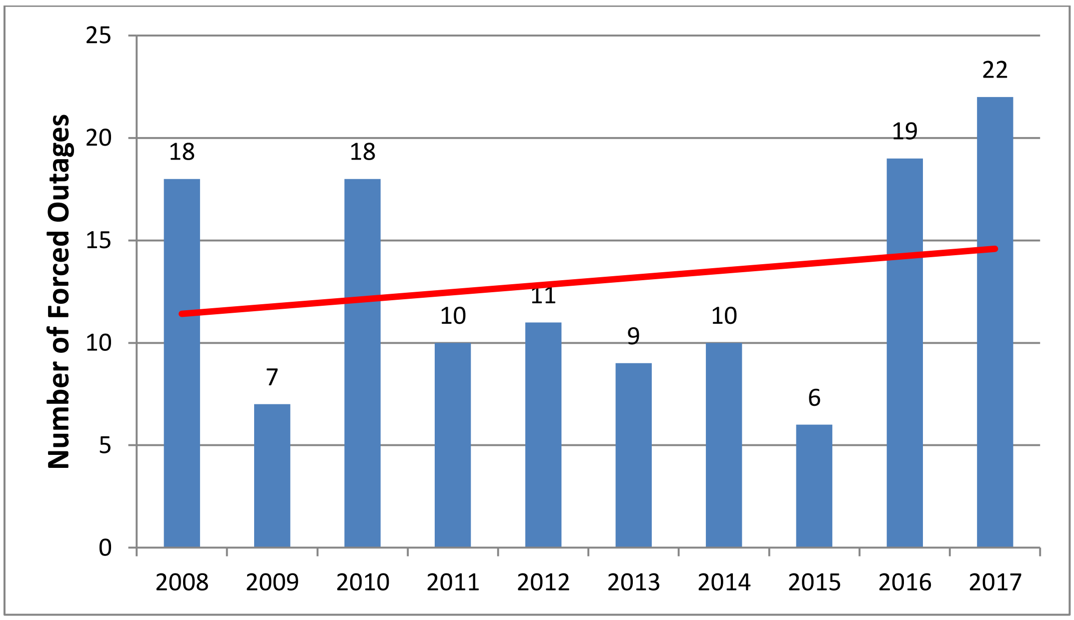


Figure 4 - Forced Outage Frequency Due to Wood Pole Failures

The forced outage duration due to wood pole failures, shown in Figure 5, demonstrates a general improvement over the past ten years. The relatively high outage incidences and durations in 2016 and 2017 may point to the start of an upward trend (although a few more years of data would be needed to be certain).

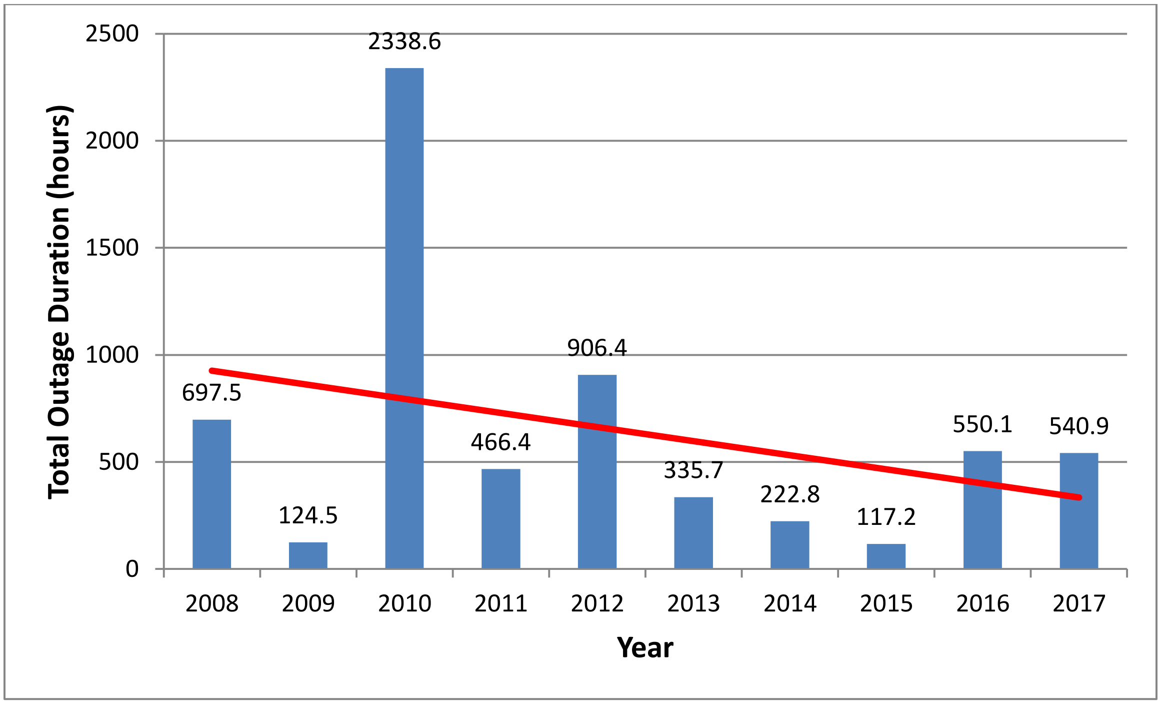


Figure 5 - Forced Outage Duration due to Wood Pole Failures

Investment Description

Hydro One will continue to replace wood poles that have failed condition assessments and any remaining Gulfport structures. Although failures in this population can occur at any time, the likelihood increases during severe weather events. Therefore, the objective is to clear the existing backlog of end of service life structures by 2024.

Replacement candidates are selected based on condition assessments. Wood pole structure condition is collected from visual inspections of the various components that make up the structure, including the cross-arms. Visual inspections include both a detailed helicopter inspection to assess the upper area of wood structures and a ground line inspection to assess the lower part of wood structures. In addition to the visual inspections, other diagnostic testing that focuses on internal rot and wood pecker holes is used to assess condition. Representative samples of wood poles are drilled once they meet a certain age criteria to determine the presence of internal rot.

The wood pole structures scheduled for replacement in the five years will be replaced with new wood pole or composite structures. The Program targets the replacement of approximately 800 wood poles each year, totalling 4,000 wood poles over the five planning years 2020-2024. This represents an average annual replacement rate of 2%. This rate of replacement has been able to keep pace with end of life wood poles identified through inspections as well as address other known wood pole deficiencies on the transmission system.

Outcome

As a result of the Program, Hydro One will maintain system reliability, and reduce safety risk to employees and the public associated with failing structures. Through customer engagement process, Hydro One has heard from its customers that they need Hydro One to pay more attention to addressing situations today that can provide greater reliability and lower costs in the future. The Program is an exemplary investment to address all of the aforementioned concerns.

The following table presents anticipated benefits as a result of the Program in accordance with the OEB's Renewed Regulatory Framework:

Outcome Summary

Customer Focus	• Reduce public safety risk associated with wood pole failures • Maintain customer reliability by replacing end-of-life wood poles
Operational Effectiveness	• Maintain system reliability by replacing end-of-life wood poles • Proactive wood pole replacement will reduce emergency restoration frequency

C. EXPENDITURE PLAN

Table 2 below presents forecasted costs for the Program. Costs for the Program are based on an average unit cost estimate calculated utilizing historical replacement costs.

Table 2 - Total Investment Cost

($ Millions) [1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital and Minor Fixed Assets[2]	0.0	55.4	56.6	57.6	58.8	60.0	0.0	288.4
Less Removals	0.0	4.4	4.5	4.6	4.7	4.8	0.0	23.1
Gross Investment Cost	**0.0**	**51.0**	**52.0**	**53.0**	**54.1**	**55.2**	**0.0**	**265.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**51.0**	**52.0**	**53.0**	**54.1**	**55.2**	**0.0**	**265.3**

[1] *Due to the in-year nature of program investments, only 2020-2024 expenditures are shown*
[2] *Includes Overhead at current rates.*

The following factors affect the capital expenditures required for the Program:

- Structure type – The cost varies depending on whether it is single pole, two-pole or three-pole structure. The larger the structure, the more expensive it is to replace. Likewise, a dead-end structure will be more difficult and costly to replace.
- Pole size – There are various pole heights depending on the voltage level and ground clearance requirements, and larger poles may require heavier equipment to replace.
- Location of the pole (whether it is easily accessible or in a remote area) – Accessibility is very important, as having to clear brush and build roads adds significant costs.

- Environmental restrictions (whether it's a sensitive area to access) – crossing an environmentally sensitive area requires time and money to be spent on permits.
- Work bundling – it is cheaper to replace poles that are in the same area if some costs can be shared between them.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: The "Do Nothing" - Reactive Pole Replacement involves waiting for the wood poles that are at end-of-life to fail and replace the failed wood poles on a reactive basis. This alternative has been rejected since the reactive management of transmission lines wood poles would lead to increased asset failures resulting in elevated safety and reliability risks. In addition, as wood poles deteriorate and reach end-of-life, emergency restorations and trouble calls would increase. This has a direct and significant impact on customers, who may be faced with long outages due to the radial nature of many wood pole lines.

Alternative 2: Planned Pole Replacement at the Optimal Level is based on replacing end-of-life wood poles at a rate that addresses confirmed end-of-life assets, resulting in elimination of backlog of end-of-life wood poles. This alternative would lead to long term cost savings by improving the operation efficiency and reducing reactive replacements. The wood poles would be managed optimally, where defects and end-of-life wood poles are addressed in a timely and proactive manner. This alternative is rejected as it is not deemed prudent to pursue based on the risk mitigated for the funding required

Alternative 3: Pole replacement Based on Risk Mitigation Assessments is the preferred undertaking. Plan to replace end-of-life wood poles based on risk mitigation assessments. This alternative will address end-of-life wood poles to mitigate the safety and reliability risks that balance wood poles needs, resource availability, and cost impact to customers. This alternative is selected, as it will maintain the safety and reliability of the transmission system.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the Program include access to the assets depending on the season, and equipment outage availability. These risks are mitigated through extensive planning, scheduling and outage coordination across lines of business and stakeholders. Furthermore, a thorough risk assessment workshop is performed during the initial Program planning phase where all known risks are identified and mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize to a minimum the loss of supply to the customer (i.e. switching a customer to an alternative supply). Outage planning also aims to synchronize Hydro One supply outages with the customer’s planned maintenance driven outages.

SR-22 Steel Structure Coating Program

Start Date:	Q1 2020	**Priority:**	Medium
In-Service Date:	Program	**3-year Test Period Cost ($M):**	55.5
Trigger(s):	Cost Avoidance, Preventative Maintenance / System Renewal, Safety, Reliability		
Outcomes:	Extends the life of steel structures by coating them and thus preventing costly future capital investments into complex repairs or structure replacements;		

A. OVERVIEW

Steel Structure Coating Program (the "Program") involves coating transmission line steel structures that are corroding. Coating the steel structure with zinc-based product will provide on-going protection to the underlying carbon steel and preserve the steel structure. Given the condition and the risks associated with steel structure failures, the Program is required to avoid tower failure, negative impacts to reliability and increased costs for tower replacements. Avoiding significant costs in the future through tower coating is the objective of the Program. Doing so will provide economic benefit and value to ratepayers because a relatively small investment now will result in large savings to customers in the future. The tower coating program is an exemplary investment that considers repair versus replace options. In this case, repairing the asset by coating, which extends asset life, is clearly the preferred option that results in a significant present value positive investment. Hydro One has evaluated various alternatives for the Program, as described below, and concluded that the coating of 2260 (260 in 2020 and 500 in 2021-2024) corroded steel towers balances the safety and reliability risks with the economic benefits. The projected costs of the Program are estimated to be $55.5 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

Steel structures elevate transmission lines above the ground, providing clearance from ground objects and separation between the circuit conductors and other line components. These structures have various designs, sizes and configurations and support transmission circuits from 115 kV to 500 kV.

Steel structures are manufactured from carbon steel and protected by hot dip galvanizing (“HDG”), a zinc based product to protect the steel from corrosion. Based on the studies conducted by corrosion experts, such as Electric Power Research Institute (“EPRI”), the service life of steel structures is primarily dependent on the condition of its HDG, as once a structure has lost its galvanizing protection the carbon steel is exposed to the environment, and the corrosion rate of the structure accelerates by a factor of eight to ten. If steel corrosion is not addressed prior to corrosion setting in, the steel structure will begin to lose structural strength and the only option would be partial or complete replacement of the tower. When the structural strength diminishes below design strength, the integrity and capacity of the structure is compromised and a failure may occur under certain weather loading conditions. Figure 1 illustrates the steel transmission towers from Sarnia region that are 72 years old which exhibit heavy pitting corrosion and require complete replacement.

Figure 1 - Steel Structures in the Sarnia area exhibiting heavy pitting corrosion

Recoating the structure with zinc-based product will provide on-going protection to the underlying carbon steel and preserve the steel structure. It will extend the steel tower service life by restoring the protective layer of galvanized coating, thereby avoiding the more costly option of replacement.

Hydro One retained EPRI to conduct an engineering study to define corrosion zones and corrosion rates in the province of Ontario and assess impact of corrosion to Hydro One's transmission towers. The study includes condition assessment of steel towers located in various corrosion zones. In conducting its study, EPRI utilized the international standard, ISO 9223:2012, *Corrosion of metals and alloys - Corrosivity of atmospheres – Classification.* The ISO 9223:2012 establishes a classification system for the corrosivity of atmospheric environments. Using the ISO 9223:2012, EPRI completed its study and established that the province of Ontario is divided into four corrosion zones ranging from C2 to C5. Each of these corrosion zones has a range of corrosion rates which can be used to estimate the service life of HDG steel based on its location. C2 and C3 zones are defined as light corrosion zones and the towers will be protected and maintained in good condition for minimum of 115 years without requiring any coating. Based on Hydro One asset records, there are approximately 39,000 steel structures in these light corrosion zones and 2,200 of them are older than 100 years. However, none of them are older than 115 years and there is no immediate tower coating needs for structures within these zones.

C4 & C5 zones are defined as heavy corrosion zones which have high and very high corrosion rates, respectively, for zinc and carbon steel. Figure 2 illustrates corrosion zones in Ontario. Based on EPRI study, the towers will, on average, lose their protective zinc 45 years after installation in C5 zones. Furthermore, they would lose 10% of their metal in the following 30 years. At this stage, structures are no longer able to withstand the original design loads and either a major refurbishment or complete tower replacement would be required. Applying these results to Hydro One’s steel tower population, the EPRI study indicated that a significant portion of towers located in very high corrosion zones are in need of coating to arrest further deterioration and prevent eventual replacements. Appendix “A” attached is a reference guide from ISO 9223:2012 that provides a description of typical atmospheric environments related to the estimation of corrosivity categories (C1 to C5).

C1 and CX zones are not applicable to Hydro One assets in Ontario, as they refer to very light corrosiveness (i.e. arctic environments) or very heavy corrosiveness (i.e. marine coastal environments) respectively.

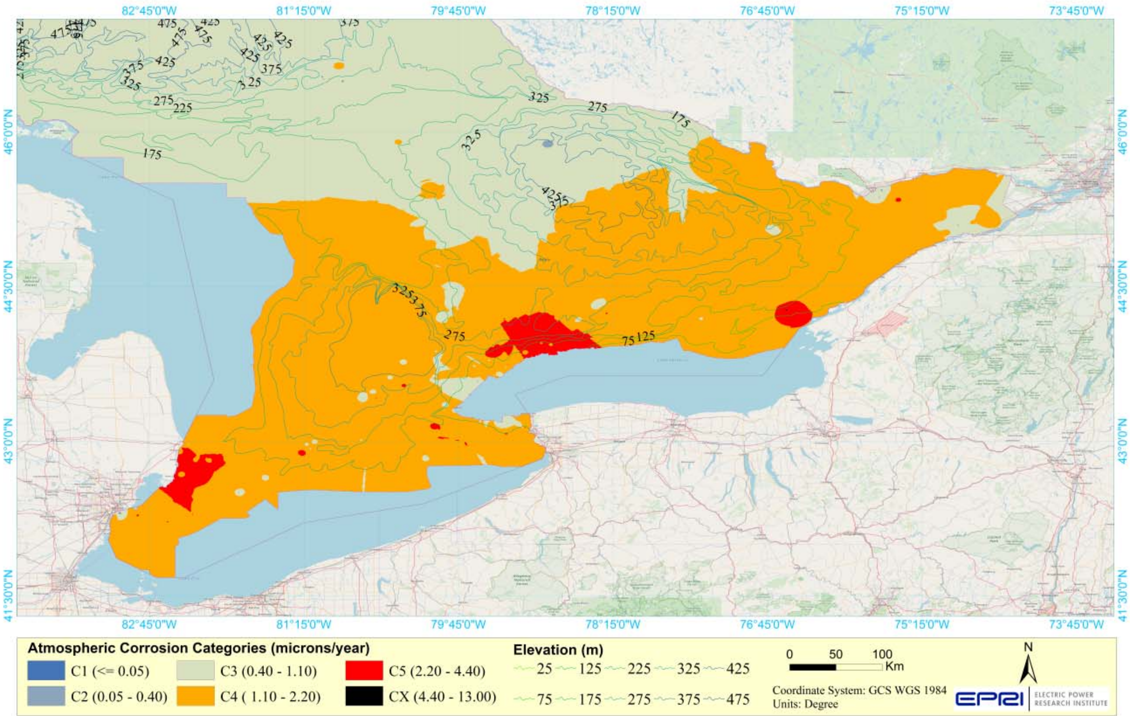


Figure 2 - Corrosion zones in Ontario, courtesy of EPRI, 2017

Table 1 shows the demographics of the steel structure population. Hydro One has 52,250 steel structures that have an average age of 58 and an expected service life ("ESL") of 80 years. There are approximately 13,000 steel towers that are located in very high (C5) corrosion zones such as Windsor, Sarnia, Hamilton, Kingston and GTA.

Based on the current assessment, 6% of Hydro One's steel structures have been recoated, 8% require major refurbishment or replacement, and 14% require coating that will be addressed as part of the steel structure coating program. 72% of the structures are currently in good condition and are not expected to require any maintenance in the near future. This assessment is continuously reviewed and updated as more structures are assessed and inspected.

Table 1 - Steel Structure Demographics

	Quantity	Average Age	ESL (Years)	Beyond ESL currently	Beyond ESL 2024	Beyond ESL 2029
Steel Towers in Light Corrosion Zones	37,300	59	80	6,605	8,005	9,510
Steel Towers In Heavy Corrosion Zones	13,000	59	80	3,000	3,550	4,150
Steel Poles	1,950	33	80	85	95	150
Total	**52,250**	**58**	**80**	**9,690**	**11,650**	**13,810**

A transmission steel tower is deemed to have reached its end of life ("EOL") when it has experienced 10% metal loss, rendering it incapable to withstand design loads. A new tower comes with a layer of protective zinc applied over bare steel via hot-dip galvanizing process. This layer varies in thickness. The American Society of Testing and Materials ("ASTM") specifies a minimum thickness of 100 microns for tower steel. It is common for a fabricator to deliver steel with an average zinc thickness of 150 microns. The most common steel member thickness for 115 and 230 kV towers is 8mm i.e. 8000 microns. In very high (C5) corrosion areas, the average annual zinc corrosion rate is 3.3 microns and bare steel is 27.5 microns, as described by EPRI.

- Most common steel member thickness = 8mm.
- EOL Criteria = 10% loss of steel thickness, 800 microns
- Opportunity to coat = in the time interval between when the zinc layer is nearly depleted and before EOL.

New steel members come with 150 microns zinc layer. At the average annual zinc corrosion rate of 3.3 microns, it takes 45 years (150/3.3=45) to deplete the zinc layer. Once the zinc layer is depleted, the exposed bare steel corroding at an average annual rate of 27.5 microns will take 29 years (800/27.5=29) to lose 800 microns of thickness. Thus, a tower in C5 very high corrosion area will, on average, reach EOL in 74 years (45+29). Therefore, the window of opportunity to economically extend life of towers located in high corrosion areas via coating is when a tower reaches around 45 years and before 75 years. As the towers exceed 75 years, various level of refurbishment effort will be required to restore strength before coating can be applied. Eventually, costly refurbishment or tower replacement becomes the only feasible option.

Investment Description

The Program is a preventive maintenance investment or asset life extension program where costs are incurred today to avoid far greater costs in the future. As discussed above, Hydro One Transmission currently owns and manages 52,250 steel structures.

As part of the Program, Hydro One targets steel towers that are located in very high (C5) corrosion zones. As described previously, towers in these zones lose their protective zinc after an average of 45 years, and 10% of their metal in the following 30 years. At this stage, structures are no longer able to withstand the original design loads and either a major refurbishment or complete tower replacement would be required. Currently, there are approximately 13,000 steel towers located within very high corrosion zones. Of 13,000 steel towers, 7,500 towers have met coating criteria and are within the window of opportunity for coating. 55 percent of the 7,500 towers (4,125) are currently experiencing corrosion and metal loss. As these towers approach 75 years old, the ability to extend their service life by coating diminishes.

Hydro One intends to complete coating of an average of 452 steel towers per year between 2020 and 2024. This is a total of 2,260 towers, which are selected from the 4,125 structures that are already experiencing corrosion and metal loss.

The steel tower coating program has mainly been driven by economic considerations rather than risk mitigation. Based on the most recent analysis, the net present value

("NPV") calculations show significant savings from tower coating versus tower replacement. Over the 5-year planning period (2020-2024), savings are estimated at $162 million compared to single isolated tower replacements, or $101 million compared to single tower replacements that are part of a multiple tower replacement project (i.e. replacing multiple towers is more efficient resulting in comparatively lower savings from tower coating). Avoiding investment today exacerbates the quantum of investment in the future and drives higher future rates, which is contrary to the public interest.

Outcome:

As a result of the Program, Hydro One will maintain reliability, address employee and public safety concerns and minimize future costs. Coating steel structures before they lose their zinc protective layer prolongs their life and prevents higher capital expenditures in the future. The integrity of steel structures is critical to the reliability of the system and to public safety. If a tower corrodes enough, it could fail, causing damage to property, injury to people present in the proximity or potentially even death. Furthermore, through customer engagement process, Hydro One has heard from its customers that they need Hydro One to pay more attention to addressing situations today that can provide greater reliability and lower costs in the future. The Program is an exemplary investment to address all of the aforementioned concerns.

The following table presents anticipated benefits as a result of the Program in accordance with the OEB's Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• This investment will maintain the long term reliability of the system by optimizing investment costs today and provide improved reliability and lower costs in the future.
Financial Performance	• Defer capital replacement costs by coating transmission line steel structures to preserve structural strength and extend service life.

C. EXPENDITURE PLAN

Table 2 presents forecasted costs for the Program. Costs for the Program are based on an average unit cost estimate calculated utilizing historical costs.

Table 2 - Total Investment Costs

($ Millions) [1]	**Prev. Years**	**2020**	**2021**	**2022**	**2023**	**2024**	**Forecast 2025+**	**Total**
Capital and Minor Fixed Assets[2]	-	11.4	21.8	22.3	22.7	23.2	-	101.3
Less Removals	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Gross Investment Cost	**-**	**11.4**	**21.8**	**22.3**	**22.7**	**23.2**	**-**	**101.3**
Less Capital Contributions	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Net Investment Cost	**-**	**11.4**	**21.8**	**22.3**	**22.7**	**23.2**	**-**	**101.3**

[1] *Due to the in-year nature of program investments, only 2020-2024 expenditures are shown*
[2] *Includes Overhead at current rates.*

The following factors affect the capital expenditures required for the Program:

- Structure type/size – Depending on the voltage of the line, the structures will be different sizes. As the voltage increases, so does the size of the structure. Structure type also impacts the cost, as dead-end towers are bigger than suspension and will cost more to coat;
- Location of the structure (whether it is easily accessible or in a remote area) – Accessibility is very important, as having to clear brush and build roads adds significant costs;

- Environmental restrictions (whether it is a sensitive area to access) – crossing an environmentally sensitive area requires time and money to be spent on permits;
- Work bundling – it is cheaper to coat towers that are in the same area if some costs can be shared between them; and
- Live-line work (whether work can be performed live-line) – conducting coating without an outage is a major benefit to work scheduling and can optimize resource deployment

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: The "Do Nothing" - Reactive Replacement of Failed Structures involves reactive responding and replacing failed steel structures that are at EOL. This alternative has been rejected because reactive management of transmission lines structures would lead to increased asset failures, resulting in elevated safety and reliability risks. Further, as steel structures deteriorate and reach EOL, the cost to perform demand emergency repairs would cause a high financial impact on the company and its ratepayers.

Alternative 2: Coating at the Optimal Level is based on coating steel structures at a rate that is coordinated with the optimal period in the structures' life cycle at which coating is most beneficial. This plan would eliminate the backlog of eligible steel structures, and reduce future reactive replacement/repair costs. This alternative is not deemed prudent to pursue based on Hydro One's decision to prioritize investments that mitigate the most safety and reliability risk over investments predominantly driven by economic benefits.

Alternative 3: Coating at Currently Planned Pacing is the preferred undertaking because it aligns with the EB-2016-0160 Decision. Under these budget constraints, Hydro One strived to balance safety and reliability risks with economic benefits. Poor condition steel structures that are eligible for coating will be coated proactively, in order to maintain long term reliability and provide maximum value to ratepayers.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the Program include access to the assets depending on the season, availability of qualified resources, and line outage availability. These risks are mitigated through extensive planning, scheduling and outage coordination across lines of business and stakeholders. Furthermore, a thorough risk assessment workshop is performed during the initial Program planning phase where all known risks are identified and mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize the loss of supply to the customer (i.e. switching a customer to an alternative supply). Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages.

APPENDIX "A"

Description of typical atmospheric environments related to the estimation of corrosivity categories (ISO:9223:2012)

Corrosivity category[a]	Corrosivity	Typical environments — Examples[b]	
		Indoor	Outdoor
C1	Very low	Heated spaces with low relative humidity and insignificant pollution, e.g. offices, schools, museums	Dry or cold zone, atmospheric environment with very low pollution and time of wetness, e.g. certain deserts, Central Arctic/Antarctica
C2	Low	Unheated spaces with varying temperature and relative humidity. Low frequency of condensation and low pollution, e.g. storage, sport halls	Temperate zone, atmospheric environment with low pollution (SO_2 < 5 µg/m^3), e.g. rural areas, small towns Dry or cold zone, atmospheric environment with short time of wetness, e.g. deserts, subarctic areas
C3	Medium	Spaces with moderate frequency of condensation and moderate pollution from production process, e.g. food-processing plants, laundries, breweries, dairies	Temperate zone, atmospheric environment with medium pollution (SO_2: 5 µg/m^3 to 30 µg/m^3) or some effect of chlorides, e.g. urban areas, coastal areas with low deposition of chlorides Subtropical and tropical zone, atmosphere with low pollution
C4	High	Spaces with high frequency of condensation and high pollution from production process, e.g. industrial processing plants, swimming pools	Temperate zone, atmospheric environment with high pollution (SO_2: 30 µg/m^3 to 90 µg/m^3) or substantial effect of chlorides, e.g. polluted urban areas, industrial areas, coastal areas without spray of salt water or, exposure to strong effect of de-icing salts Subtropical and tropical zone, atmosphere with medium pollution
C5	Very high	Spaces with very high frequency of condensation and/or with high pollution from production process, e.g. mines, caverns for industrial purposes, unventilated sheds in subtropical and tropical zones	Temperate and subtropical zone, atmospheric environment with very high pollution (SO_2: 90 µg/m^3 to 250 µg/m^3) and/or significant effect of chlorides, e.g. industrial areas, coastal areas, sheltered positions on coastline

SR-23 Tower Foundation Assess/Clean/Coat Program

Start Date:	Q1 2020	**Priority:**	Medium
In-Service Date:	Program	**3 Year Test Period Cost ($M):**	57.0
Trigger(s):	Cost Avoidance, Preventative Maintenance / System Renewal, Safety, Reliability		
Outcomes:	Extends the life of foundations by re-coating them and thus preventing costly future capital investments into complex repairs or tower replacements; maintains system reliability by preventing foundation and tower failures; prevents towers from collapsing and potentially causing public injuries or fatalities		

A. OVERVIEW

Tower Foundations Assess/Clean/Coat Program (the "Program") involves coating and/or repairing steel structure tower foundations that have deteriorated to the point of increasing their risk of failure (which could include structure collapse), and impacting public safety and system reliability. The Program focuses on steel grillage footings and anchors, which due to their age and material sustain a higher incidence of corrosion. The need of the Program is asset condition driven. The scope of the Program includes those steel grillage footings where coating or minor repairs can be applied to extend the foundation's service life. However, where severe corrosion has caused significant strength reduction, the steel foundation will be identified as a candidate for major repair or replacement.

The proposed plan will assess, clean, and coat 820 grillage foundations in 2020 and 1600 foundations per year from 2021-2024. Hydro One has evaluated various alternatives for the Program, as described below, and concluded that the assessing, cleaning and coating of 7220 tower foundations and anchors is the most cost effective and efficient undertaking. The projected costs of the Program are estimated to be $57.0 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

Foundations support and anchor transmission structures to the ground and enable the structures to withstand the weight of the structure itself, attached components and weather related external forces such as wind and ice. There are three dominant foundation types in Hydro One's transmission system: cast-in concrete footings, steel grillage footings, and steel anchors. Hydro One is currently focusing on grillage footings and anchors, which due to their age and material sustain a higher incidence of corrosion. Concrete footings are younger and are not displaying signs of corrosion.

From the early 1900s into the 1960s, most lattice steel structures were constructed with a grillage (buried steel) foundation. There are approximately 32,000 grillage footings and approximately 3,500 guyed structures which rely on the integrity of the steel grillage and anchors for support. Steel tower grillage foundations and anchors are fabricated with a zinc-based galvanized coating which protects the underlying steel against corrosion. Coating life can vary considerably depending on the surrounding environment. Once the galvanizing has been depleted, the underlying bare steel begins to corrode; typically much faster than with the galvanized coating. The accelerated corrosion results in metal loss which reduces the mechanical strength of the grillage foundation.

All steel grillage foundations that are in Hydro One fleet are or will be 50 years or older during the course of the next five years and, as such, will need to be assessed through the Program. When a steel grillage footing foundation reaches 50 years old, it becomes prone to degradation. Currently, 32% of steel grillage footing population is beyond its End of Service Life ("ESL"). Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions. The average ESL of the steel grillage footing fleet is 80 years. Assuming no repair and/or replacement, Hydro One anticipates that approximately 12,185 units (38% of the steel grillage footing population) will exceed their ESL by 2024 and 14,360 units (45% of the population) will exceed their ESL by 2029.

The need is determined based on foundation type and consequence of asset failure. Based on condition assessment, where severe corrosion has caused significant strength reduction, the foundation will be identified as a candidate for major repair or replacement. The failure of foundation could directly result in structure failures which could cause a lengthy system operation interruption and a possible employee or public safety concern. Furthermore, damaged foundations could result in very costly repairs or even necessitate the replacement of the entire tower.

Figure 1, Figure 2, and Figure 3 illustrate damaged grillage footings. The towers eventually had to be replaced due to the damage.

Figure 1 - Towers sitting in water causes the foundations to corrode, leading to towers leaning (circuit D2L, near North Bay, ON)

Figure 2 - Buckled legs and tower leaning (circuit M80B, Minden, ON)

Figure 3 - Leg and diagonals are corroded through, necessitating costly repairs (circuit D2L)

Investment Description

The Program is intended to inspect, assess, clean and coat the steel grillage footings buried underground, to restore any depleted coating protection and extend the foundations' service life. The Program also includes minor repairs on damaged footings and identification of footings that need major repair or replacement.

The refurbishment candidates are selected based on condition assessments. If no metal loss is visible at the time of assessment, the footings and/or anchors are re-coated to restore the corrosion protection and extend the life of the components. If metal loss is visible at the time of assessment, the affected components are scheduled for refurbishment.

The Program is focused on assessing, restoring, and refurbishing the grillage foundations to extend the life of the steel that is at or below the ground line. This is achieved through two planned activities:

1. Assess/Clean/Coat – This activity assesses the condition of a tower's foundation and either immediately coats it or schedules future repairs. The decision to coat or repair depends on the severity of the corrosion that is found and the complexity of potential repairs.
2. Foundation Refurbishment – This activity completes more complex repairs and/or replaces the foundations identified during previous assessment activities.

The proposed plan will assess, clean, and coat 820 grillage foundations in 2020 and 1600 foundations per year from 2021-2024. As per Hydro One strategy for steel structure and foundation, this program is to prioritize the foundations based on line voltage, type of structures and geographic location of the lines. For example, the current plan is focusing on 500 kV guyed towers located in Northern region where most of towers are located in wetland or muskeg area. These towers were built in 1960s and there is a high volume of tower foundation failures.

Outcome

The Program will maintain system reliability and mitigate public safety concerns by addressing 7,220 grillage foundations over the five year plan and extending the life of steel structure foundations.

The following table presents anticipated benefits as a result of the Program in accordance with the OEB's Renewed Regulatory Framework:

Customer Focus	• Reduce public safety risk associated with steel tower failures • Maintain customer reliability by replacing end-of-life tower foundations
Operational Effectiveness	• Maintain system reliability by replacing end-of-life steel tower foundations • Proactive foundation replacement will reduce emergency restoration frequency

C. EXPENDITURE PLAN

Table 1 below presents forecasted costs for the Program. Costs for the Program are based on an average unit cost estimate calculated utilizing historical replacement costs.

Table 1 - Total Investment Cost

($ Millions) [1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	0.0	11.8	22.3	22.8	23.3	23.7	0.0	104.0
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**11.8**	**22.3**	**22.8**	**23.3**	**23.7**	**0.0**	**104.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**11.8**	**22.3**	**22.8**	**23.3**	**23.7**	**0.0**	**104.0**

[1] *Due to the in-year nature of program investments, only 2020-2024 expenditures are shown*
[2] *Includes Overhead at current rates.*

The following are some factors that affect the cost of foundation assess/clean/coat and refurbishment:

- Structure type/size – repairing the foundation on a single leg of a 500 kV tower is much more costly than a four-leg tower. Depending on the voltage of the line, the structures will be different sizes. As the voltage increases, so does the size of the structure and its foundations;
- Location of the structure: whether it is easily accessible or in a remote/swampy area – accessibility is very important, as having to clear brush and build roads adds significant costs and some work can only be performed under frozen ground conditions;
- Environmental restrictions: whether it is a sensitive area to access – crossing an environmentally sensitive area requires time and money to be spent on permits;

- Work bundling – it is cheaper to work on towers that are in the same area if some costs can be shared between them; and
- The extent of the damage - the damage will determine what kind of equipment is required to perform the repairs.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: Reactive Foundation Replacement involves a reactive responding and replacing failed tower foundations and anchors that are end-of-life. This alternative has been rejected for the following reasons:

- Reactive management of tower foundations and anchors would lead to increased asset failures, resulting in elevated safety and reliability risks;
- As tower foundations and anchors deteriorate and reach end-of-life, emergency restoration and trouble call volumes would be unmanageable;
- Due to the complicated procedure to replace a tower foundation, multiple lengthy power outages will be required, which will significantly interrupt the power supply to customers and reduce system operation reliability;
- Cost of replacing a tower foundation could be as much as 20-30 times that of clean and coating the foundation, as more labour and heavy equipment is required.

Alternative 2: Planned Foundation Coating/Repair at the Optimal Level is based on assessing, cleaning and coating steel structure foundations at a rate that is coordinated with the optimal period in the foundation's life cycle at which coating and repair is most beneficial. This alternative would eliminate the backlog of eligible steel structures foundations and reduce long term planned or reactive replacement/repair costs. This alternative is preferred for the following reasons:

1. Poor condition steel structure foundations that are eligible for coating will be coated proactively
2. Risks to transmission system safety and reliability can be mitigated by balancing asset needs, resource availability, and cost impacts.

E. EXECUTION RISK AND MITIGATION

The risks to the completion of this investment include access to the assets depending on the season, availability of qualified resources and equipment outage availability. These risks are mitigated through extensive planning, scheduling and outage coordination across lines of business and stakeholders. Furthermore, a thorough risk assessment workshop is performed during the initial Program planning phase where all known risks are identified and mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize the loss of supply to the customer (i.e. switching a customer to an alternative supply). Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages.

SR-24 Transmission Line Shieldwire Replacement

Start Date:	Q1 2020	**Priority:**	High
In-Service Date:	Program	**3 Year Test Period Cost ($M):**	37.8
Triggers: Reliability and Safety			
Outcomes: Minimize public safety risk associated with shieldwire failures; maintain system and customer reliability by replacing EOL shieldwire; proactive shieldwire replacement will help to reduce emergency restoration frequency as well as associated costs.			

A. OVERVIEW

The Transmission Line Shieldwire Replacement Program (the "Program") is required to replace End-of-Life[1] ("EOL") galvanized steel, Aluminum Conductor Steel Reinforced ("ACSR") and Copperweld shieldwire installed on Hydro One's transmission system. Due to demographic patterns and the resulting quantity of EOL shieldwire currently installed on the Hydro One system, 290 km of shieldwire is required to be replaced annually over the test period. At this rate, all shieldwire currently identified as being EOL and all critical sections of shieldwire identified during the five-year period as having reached EOL will be replaced by the end of the five-year period. If EOL shieldwire is not replaced, it is likely to break and make contact with the conductor, resulting in a circuit outage and potential customer interruption. Additionally, the broken shieldwire represents a significant safety risk as it may fall and swing to the ground. By replacing EOL shieldwire prior to failure, these reliability and safety risks are mitigated. Hydro One has evaluated various alternatives to the Program, as described below, and concluded that replacing EOL shieldwire is the most cost-effective and efficient undertaking. The projected costs of the Program are estimated to be $37.8 million over the 2020-2022 test period.

[1] EOL is defined as the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences.

B. NEED AND OUTCOME

Investment Need

There is approximately 34,600 km of shieldwire strung above Hydro One's overhead transmission lines. Shieldwire is used to provide lightning protection and grounding continuity for the transmission line. An example of transmission line shieldwire is presented in Figure 1.

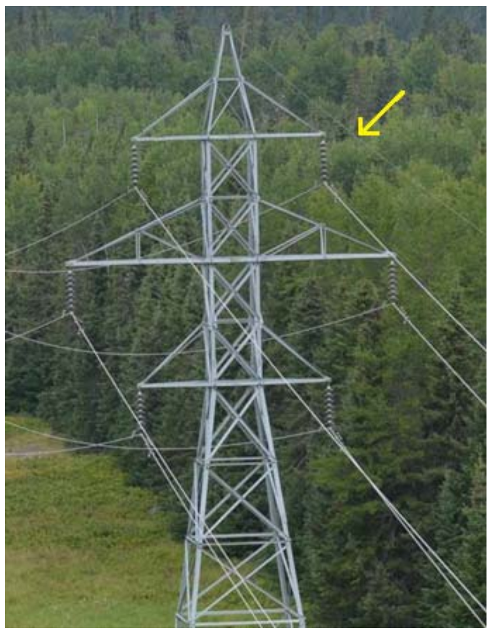


Figure 1 - Transmission Line Shieldwire

Hydro One's network has five types of shieldwire; Galvanized Steel, Alumoweld, Optical Ground Wire ("OPGW"), Aluminum Conductor Steel Reinforced and Copperweld. The breakdown of shieldwire by type currently installed on the Hydro One network is displayed in

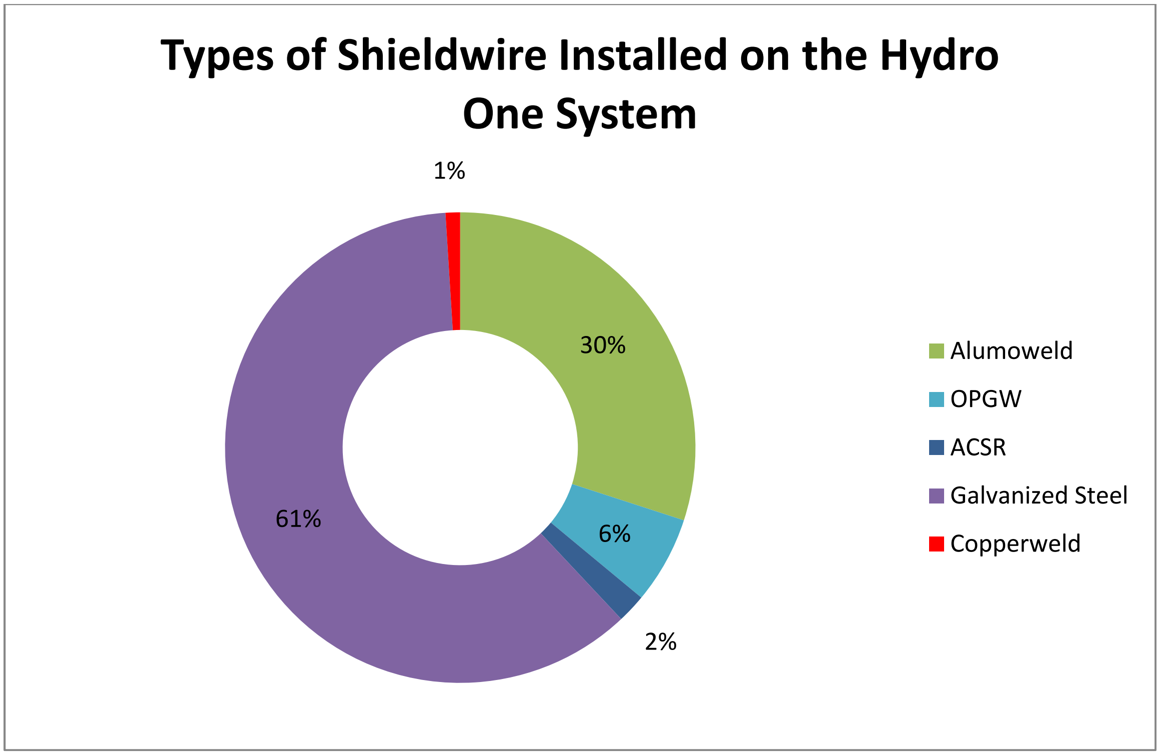


Figure 2: Shieldwire by Type

Galvanized steel is the most common type of shieldwire currently installed on the Hydro One transmission network. Galvanized steel shieldwire is no longer installed by Hydro One because its protective zinc coating tends to deteriorate over time, thereby reducing its mechanical strength and leading to eventual failure. Aluminum cladded steel, also known as Alumoweld, is the most recent type of shieldwire installed on Hydro One's network and is being used to replace shieldwire that has reached EOL. In locations where a fibre optic communication channel is required for telecommunication purposes, Hydro One installs OPGW, which consists of Alumoweld shieldwire with a core containing fibre optic strands. ACSR conductors are also installed as shieldwire in limited cases where estimated fault current levels are too high for conventional galvanized steel or Alumoweld wires. Copper cladded steel, also known as Copperweld, is the final type of shieldwire at Hydro One and was previously installed in limited numbers across the network. Copperweld is not capable of adequately sustaining lightning strikes and is therefore targeted for replacement.

Witness: Donna Jablonsky

Shieldwire cannot be maintained or repaired to extend its service life. Rather, Hydro One's shieldwire population is monitored through the condition assessment program and is only replaced once condition warrants. As of 2016, Hydro One began utilizing a non-destructive testing device that is able to assess shieldwire condition without requiring a circuit outage. With the cost and difficulties associated with obtaining an outage eliminated, Hydro One is now able to more easily assess shieldwire condition.

Hydro One does not replace shieldwire based upon age since a multitude of factors, including geographic location, weather and atmospheric contamination contribute to shieldwire lifespan. A detailed condition assessment is used to determine when shieldwire has reached EOL. Line sections of shieldwire are targeted for condition assessment after reaching an established age threshold, which varies based on the shieldwire type. Once selected for condition assessment, the remaining tensile strength and corrosion levels on the shieldwire are examined to determine the remaining service life. If the condition assessment results indicate that the shieldwire has not yet reached EOL, it is scheduled for re-assessment at a later date; otherwise, it is scheduled for replacement under the Program.

If the EOL shieldwire is not replaced, it is at high risk of breaking. As broken shieldwire falls, it often makes contact with the conductors below it, causing a circuit outage and decreased reliability to customers. Broken shieldwire that falls in an urban area will also pose a high public safety risk. Broken shieldwire may hit a pedestrian, employee, vehicle or public property as it falls or blows in the wind, and has the potential to cause severe injury and property damage. Examples of shieldwire failure experienced at Hydro One can be found in Figure 3 to Figure 5 below.

To maintain system reliability and public safety, EOL shieldwire must be replaced under the Program. Due to the safety and reliability concerns associated with shieldwire replacement, completion of this program is considered a high priority.

Witness: Donna Jablonsky

Figure 3: 2016 Shieldwire Failure on K2Z

Figure 4: 2016 Shieldwire Failure on D10H

Figure 5: 2017 Shieldwire Failure on S22A

Investment Description

Hydro One's Shieldwire Replacement Program actively replaces galvanized steel, ACSR and Copperweld shieldwire that has reached EOL. Alumoweld and OPGW are the most recent shieldwire installations on Hydro One's network and have not yet reached EOL. The Program includes all design, procurement, field verification, installation and commissioning required to replace the EOL shieldwire with new Alumoweld or OPGW, including the necessary dampers and associated attachment hardware.

Due to historical construction and demographic patterns, Hydro One is now entering into a period where the shieldwire on many overhead transmission line sections has reached EOL. In order to effectively manage these circuits and prevent shieldwire related outages, this Program targets the replacement of 290 km of shieldwire per year from 2020 to 2024. This represents an average replacement rate of about 0.8% over each year. At this replacement rate, all backlogged shieldwire previously identified as having reached EOL and all critical sections of shieldwire identified during the five year period as having reached EOL will be replaced by the end of the five year period.

Outcome

Hydro One aims to achieve the following outcomes as a result of the Program:

- Maintain system and customer reliability by replacing EOL shieldwire and mitigating outages caused by failing shieldwire
- Reduce the likelihood of employee and public safety incidents related to falling shieldwire. The likelihood of such injuries occurring can be reduced if EOL shieldwire is replaced.
- Replace 0.8% of Hydro One’s shieldwire fleet each year over the 2020 to 2024 period. At this replacement rate, all sections of shieldwire that are currently at EOL and all critical sections of shieldwire identified during the five year period as having reached EOL will be replaced by the end of the five year period.

The following table presents anticipated benefits as a result of the Program in accordance with the OEB's Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• Reduce public safety risk associated with shieldwire failures • Maintain customer reliability by replacing EOL shieldwire
Operational Effectiveness	• Maintain system reliability by replacing EOL shieldwire • Proactive shieldwire replacement will reduce emergency restoration frequency

C. EXPENDITURE PLAN

As discussed above, the Shieldwire Replacement Program is required to mitigate the safety and reliability risks associated with EOL shieldwire. Hydro One will strive to complete the Program in an effective and efficient way to minimize the cost of performing this sustainment task. The Program begins in January and ends in December of each of the test years.

Table 1 presents forecasted costs for the Program. Costs for the Program are based on an average unit cost estimate calculated utilizing historical replacement costs. Year over year costs fluctuate due to the added inflation. The replacement costs are influenced by structure type and accessibility. To replace all backlogged shieldwire previously identified as having reached EOL and all critical sections of shieldwire expected to reach EOL during the five year period, 290 km of shieldwire is required to be replaced annually through the Shieldwire Replacement Program for the next five years.

Table 1: Total Investment Cost

($ Millions) [1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	0.0	13.4	13.7	13.9	14.2	14.5	0.0	69.8
Less Removals	0.0	1.1	1.1	1.1	1.1	1.2	0.0	5.6
Gross Investment Cost	**0.0**	**12.3**	**12.6**	**12.8**	**13.1**	**13.4**	**0.0**	**64.2**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**12.3**	**12.6**	**12.8**	**13.1**	**13.4**	**0.0**	**64.2**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown
[2] Includes Overhead at current rates.

D. ALTERNATIVES:

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: Reactive Replacement of Failed Shieldwire involves replacing the EOL shieldwire once a failure occurs. This alternative has been rejected because reactive management of shieldwire would lead to an increased number of asset failures and elevated safety and reliability risks. Replacement of shieldwire on an emergency basis will require constant reprioritization of planned work and lead to inefficient redeployment of resources. Reactive shieldwire replacements would also prolong circuit outages and may therefore extend equipment and customer outages.

Alternative 2: Proactive Replacement of Critical EOL Shieldwire and Backlog is the preferred undertaking. By the end of the five year period, this alternative will replace all backlogged shieldwire previously identified as having reached EOL as well as critical sections of shieldwire identified during the five year period as having reached EOL. Shieldwire replacement will be prioritized based upon circuit criticality. Risk mitigation assessments will be conducted to balance shieldwire replacement needs with resource availability and the cost impact to customers. The risk mitigation assessment allows Hydro One to replace EOL shieldwire in a way that mitigates safety and reliability risks while balancing the asset needs, resource availability and the cost impact to customers.

Alternative 3: Proactive Replacement of All EOL Shieldwire involves planning for the replacement of all backlogged shieldwire previously confirmed to be EOL and all shieldwire that is expected to reach EOL during the five year period. Condition assessment conducted during the five year period will reveal additional sections of shieldwire that have reached EOL and require replacement. This alternative will ensure that these sections of shieldwire are replaced within the five year period, regardless of criticality. In addition to both the critical and non-critical sections of recently identified EOL shieldwire, all backlog shieldwire previously identified as having reached EOL will also be replaced. This alternative will address all confirmed EOL assets and result in the elimination of the backlog of EOL shieldwire. However, this alternative is rejected as it is not deemed prudent to pursue based on the risk mitigated for the funding required.

E. EXECUTION RISK AND MITIGATION

Implementation risks to the Program include outage restrictions and material lead time. These risks are mitigated through proactive planning and coordination well in advance of the program’s execution to ensure outage and material availability. For example, because required shieldwire lengths and sizes can vary greatly, Hydro One only stores small sections of shieldwire for emergency repair. All material required for planned replacements is ordered specifically for each project. Shieldwire and accessories can take between 6-12 months to order and receive, and will delay the planned replacement if not obtained in time. To reduce the likelihood of this delay occurring, refurbishments are planned and material is ordered approximately one year in advance.

SR-25 Transmission Line Insulator Replacement

Start Date:	Q1 2019	**Priority**	High
In-Service Date:	Ongoing Program	**3Year Test Period Cost ($M):**	204.2
Trigger(s):	Strategic, Public Safety, System Reliability		
Outcomes:	Eliminate risk to public safety by replacing defective porcelain insulators; maintain customer and system reliability		

A. OVERVIEW

Transmission Lines Insulator Replacement Program (the "Program") involves primarily the replacement of defective porcelain insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) between 1965 and 1982. These defective insulators are used province-wide in Hydro One's transmission system. The defect associated with porcelain insulators results in two failure modes: (i) mechanical failure, which cause the conductor to fall on the ground; and (ii) electrical failure which triggers a forced outage, sometimes for a prolonged period of time. These types of failures pose significant safety and system reliability concerns. Hydro One retained a third-party expert, the Electric Power Research Institute ("EPRI"), to assess the condition of defective COB and CP porcelain insulators to assist Hydro One in determining the pacing of porcelain insulator replacement. EPRI completed laboratory testing which provided overwhelming evidence to support taking immediate action to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation made by EPRI is that the population of defective COB and CP insulators installed between 1965 and 1982 be removed from service as soon as practically possible.

This Program will also address the replacement of deteriorated polymer insulators. Polymer insulators in 230 kV dead-end configurations are known to fail due to their exposure to high electric-field gradients that cause silicone degradation. The degradation exposes the fiberglass rod to moisture which causes rapid deterioration leading to failure. Hydro One retained EPRI to perform a detailed condition assessment of polymer insulators to assist Hydro One in determining the need and pacing of polymer insulator replacement. EPRI completed laboratory testing and provided technical data showing that condition varies based on voltage, manufacturer and use of corona rings. The results of this study indicate that Hydro One should plan to remove certain 230 kV insulators which show extensive degradation from service as soon as possible due to immediate or high risk of failure. Other types of 230 kV insulators should continue to be assessed periodically for signs and degree of degradation. EPRI further recommends that field staff should check the integrity of these insulators prior to performing any live maintenance procedures due to potential safety issues. As part of the Program, Hydro One will be replacing the deteriorated polymer insulators on an “as-needed” basis. Prior to replacing the polymer insulators, Hydro One will perform an asset condition assessment to ensure that the condition of a polymer insulator warrants a replacement.

Program pacing is mainly influenced by the number of defective porcelain insulators located in publicly accessible (critical) locations. Publicly accessible (critical) locations include structures located near roads, water railways, urban areas, golf courses, educational and health care facilities. Hydro One plans to replace defective porcelain insulators posing a higher public safety risk (i.e. insulators in critical locations) by 2022 at a rate of approximately 3,700 circuit structures per year. Insulators in non-publically accessible areas will be replaced at an approximate rate of 3,450 circuit structures per year over a five-year period. The projected costs of the Program are estimated to be $204.2 million over the 2020-2022 test period and the replacement quantities include both porcelain and polymer insulator replacement.

B. NEED AND OUTCOME

Investment Need

Transmission line insulators are an integral component of the transmission system. Transmission line insulators are required to perform two basic functions. They must provide mechanical support for overhead conductors and they must provide electrical isolation between the energized conductors they support and the grounded towers to which they are attached. A typical transmission line insulator is shown in in Figure 1 below.

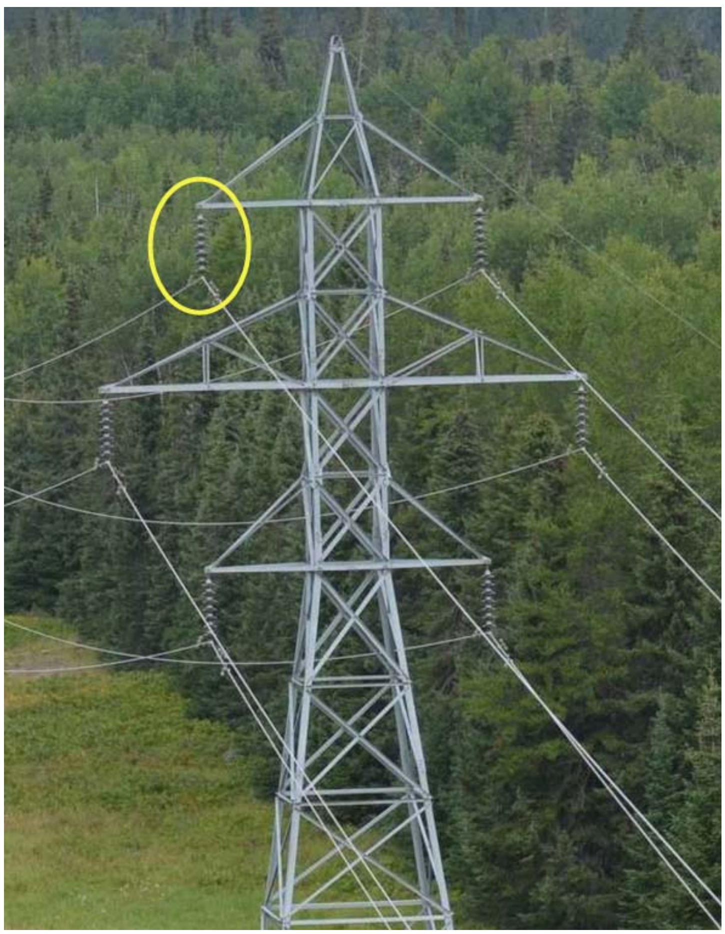


Figure 1 - Transmission Line Insulator

There are approximately 437,000 insulator strings in Hydro One's overhead transmission network. As described in TSP Section 2.2.2.4, Hydro One has three types of transmission line insulators in its fleet: porcelain, glass and polymer. The percentages of insulators by material type are shown in Figure 2. The scope of the Program includes defective porcelain insulators and deteriorated polymer insulators.

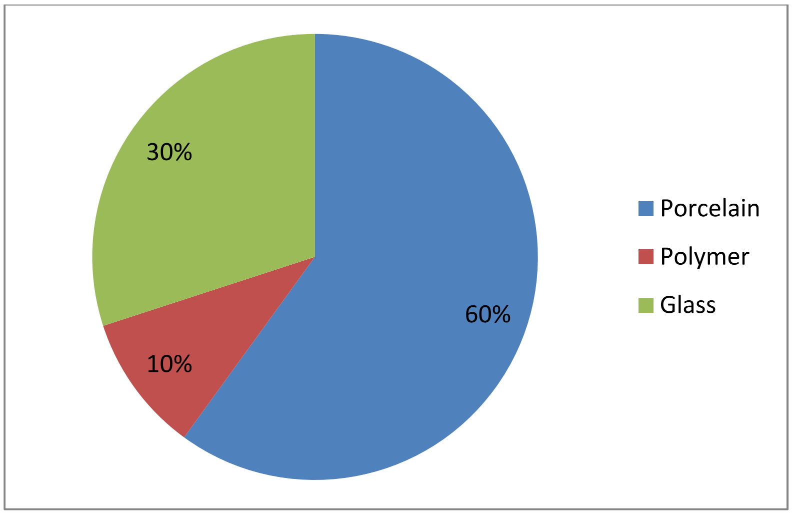


Figure 2 - Percentage of Insulators by Material

<u>Defective Porcelain Insulators</u>

Age demographics are not a driving factor for the replacement of porcelain or glass insulators since these types of insulators generally expected to outlast the life of the transmission line. However, porcelain insulators manufactured by Canadian Ohio Brass and Canadian Porcelain between 1965 and 1982 suffer from a phenomenon known as cement expansion or cement growth, as shown in Figure 3 below. It is recognized throughout the industry, that both the electrical and mechanical characteristics of line insulators manufactured between the mid-1960s and early 1980s by COB and CP deteriorate faster than other comparable insulators due to cement expansion.

Figure 3 - Porcelain Insulator Unit Affected by Cement Expansion

Porcelain transmission line insulators are specified in terms of their combined mechanical and electrical (“M&E”) strengths. For example, an insulator with an M&E rating of 36 kips (1 kip = 1,000 lbf.) is designed to withstand an applied tensile load in excess of 36 kips without mechanical or electrical failure. With respect to cement expansion, mechanical failure is defined as a physical breakage of the insulator while electrical failure is defined as cracking of the insulator’s porcelain body or cement in the area between the cap and the pin which results in a significant reduction of the insulator’s dielectric strength.

Cement expansion creates radial cracks in the cement and porcelain shell resulting in two possible failure modes:

- **Mechanical failure –** as described above, it is a physical breakage of the insulator which may result in a conductor falling to the ground. The mechanical failure poses an extremely significant risk to public and employee safety. For example, in March 2015, an insulator on circuit V76R mechanically failed causing the conductor to fall to the ground in a commercial parking lot in Etobicoke. Photos of this incident are shown in Figure 4 and Figure 5 below. Similarly, in January 2017, an insulator on circuit HL3 mechanically failed causing the conductor to fall over a roadway in Hamilton. A photo of this incident is shown in Figure 6 below.

- **Electrical failure –** cracks in the porcelain reduce the insulating properties of the material. This failure typically results in customer outages that might be prolonged due to repair time.

Figure 4 - V76R Insulator Failure

Figure 5 - V76R Insulator Failure

Figure 6 - HL3 Insulator Failure

The porcelain insulators manufactured by COB and CP are used province-wide in Hydro One’s transmission system. There are approximately 34,000 circuit structures with defective porcelain insulators and roughly 15,000 have been identified as being on structures in publicly-accessible (critical) locations. Publicly-accessible (critical) structures include those located near roads, water railways, urban areas, golf courses, educational and health care facilities. To date approximately 8,900 publicly- accessible COB and CP insulators have been replaced. A breakdown of the defective population in relation to the total insulator population can be seen in Figure 7.

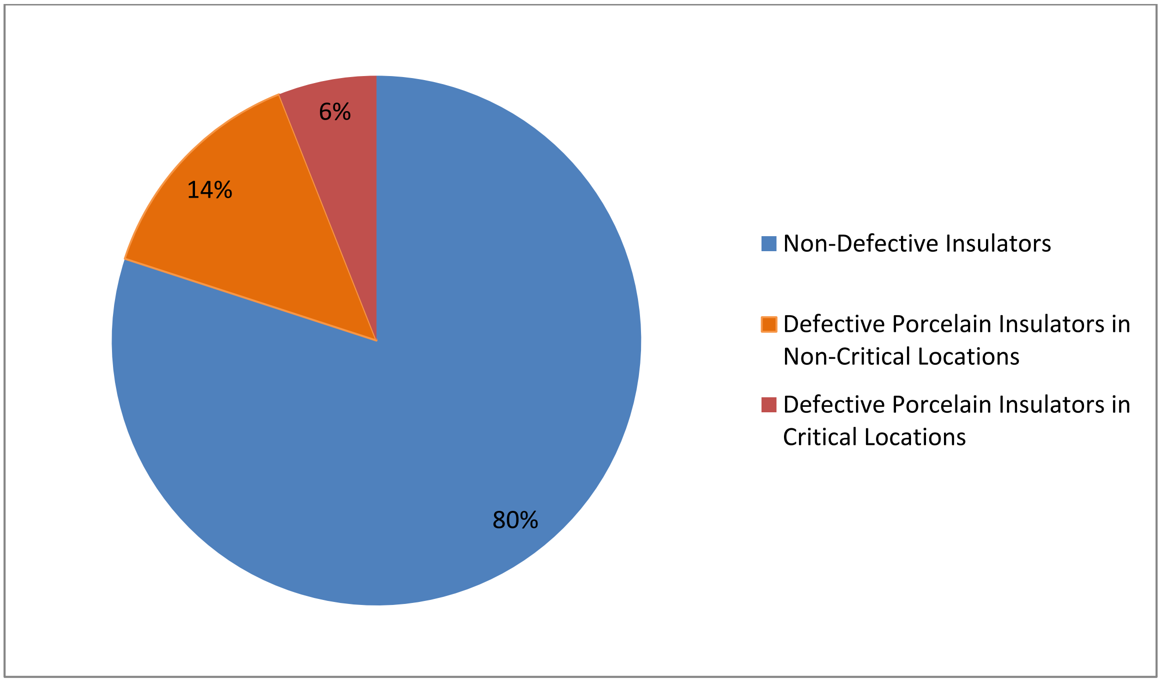


Figure 7 - Defective Porcelain Insulator Population

Figure 8 illustrates the number of COB and CP failures over the past ten years, showing an increasing trend. The number of failures is expected to rise due to the degradation of the known defective COB and CP porcelain insulators, potentially impacting public safety, system performance and customer reliability. Failed insulators normally result in a sustained forced outage due to the permanent electrical fault they create. Repair time can be significant, averaging 37 hours, depending on the location and severity of the failure.

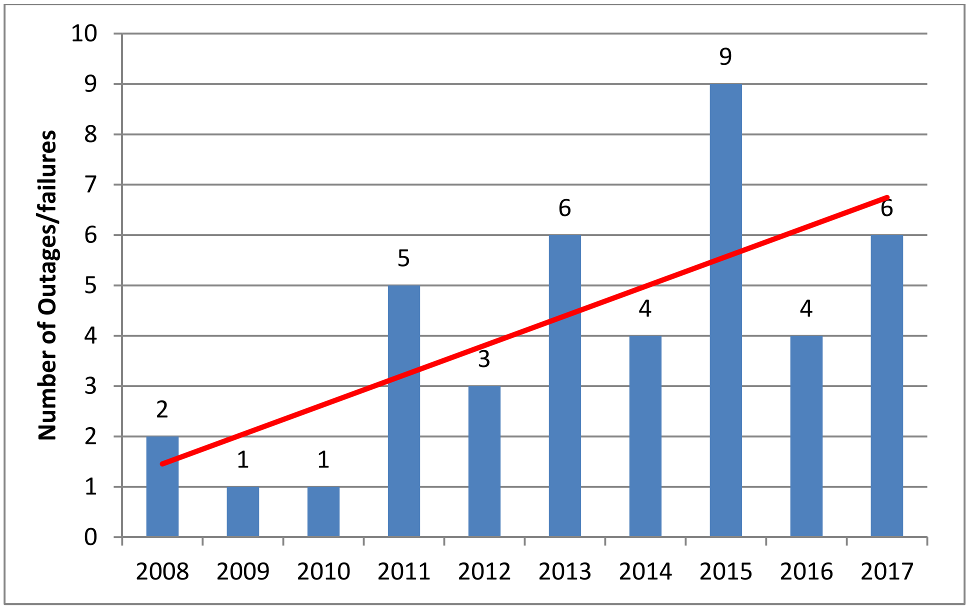


Figure 8 - Frequency of COB/CP Insulator Failures

To address concerns associated with defective porcelain insulators, Hydro One retained a third party expert, EPRI. EPRI performed laboratory testing on COB and CP porcelain insulators in order to assess the condition of defective COB and CP porcelain insulators to assist Hydro One in determining the pacing of porcelain insulator replacement. The testing program comprised of two phases. Based on the Phase one COB and CP testing results, Hydro One significantly increased the insulator replacement rate, compared to pre-2016 levels, and prioritized the replacement of insulators in publically accessible (critical) locations.

Phase one was completed in 2016 and included testing of 299 insulators removed from a combination of dead-end and suspension strings installed in publicly-accessible (critical) locations. Phase one testing was intended to provide an expedient assessment of the condition of the in-service insulators in question. The results of phase one supported the urgent replacement of COB and CP insulators manufactured between 1965 and 1982 that are installed in publicly-accessible (critical) structures where public safety is at risk.

A large proportion of the insulators tested (37%) during phase one failed electrically or mechanically at loads below their rated M&E strength. There was a significant number of punctured insulators and the test data showed a large variation in failing loads which would not be expected for a healthy insulator population. The condition of the Hydro One insulators was assessed through benchmarking against EPRI and public domain test data. This benchmarking data was obtained through testing of similar vintage insulators which had been in service for a comparable duration under similar field conditions. The performance of the Hydro One and the benchmarking insulators was also compared to current and historical requirements for new insulators. The test results presented an initial snapshot of the condition of the population of defective insulators in-service on Hydro One's transmission system. Although the sample of insulators tested was not sufficient to perform a rigorous statistical analysis upon which to base recommendations, the results strongly suggested that the installed insulator population comprising CP and COB insulators manufactured between 1965 and 1982 had reached or was at least approaching the end of useful life.

Phase two of the testing was performed in 2017. Those tests were carried out on 591 insulators. The intent of the phase two tests was to supplement the phase one data and to provide data on the rate of deterioration of the insulator population. The results of analysis showed that:

- a large number of the tested insulators exhibited porcelain cracking after M&E testing
- the propensity for the insulators to puncture (crack) during Thermal Mechanical Cycling (TMC);
- the fact that the insulators are highly susceptible to electrical puncture under steep transient voltages (e.g. lightning);
- the finding that TMC drastically decreases the already weak ability of the insulators to withstand electrical puncture; and
- a significant number of insulators separated mechanically during TMC.

These results suggest that the number of in-service punctured units will increase as the insulators experience significant mechanical loading events. When a string containing electrically punctured insulators undergoes a flashover due to lightning, contamination, or snow and ice bridging, there is a high likelihood that the ensuing power arc will pass through the punctured unit internally travelling from cap to pin, causing significant heating and pressure buildup which can cause the cap and pin to separate and the conductor to drop. The greater the number of punctured insulators found in the string, the higher the probability of string flashover and string separation. Insulators which are not punctured, but have suffered deterioration in mechanical strength do not exhibit this behavior. If a string contains mechanically compromised units, the insulators will fail if the maximum applied load exceeds the units remaining mechanical strength. The majority of conductor drops recently experienced on Hydro One’s porcelain insulated transmission system fall into the former category.

The phase one and two analyses provided overwhelming evidence supporting replacement of defective porcelain insulators to mitigate the risk to the safety and reliability of Hydro One’s transmission system. The key recommendation provided by EPRI is that the identified population of COB and CP insulators be removed from service as soon as practically possible.

Deteriorated Polymer Insulators

Hydro One uses polymer insulators on the 115 kV and 230 kV transmission system. Polymer insulators have an Expected Service Life[1] (“ESL”) of 30 years and, due to their material properties, degrade with age. First-generation polymers installed in the mid-1980s will reach their ESL during the test period and need to be evaluated for

[1] Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions.

replacement. First-generation polymers are more problematic when compared to most recent generations. When older polymer insulators were designed and manufactured, the long term effects of electric fields were not well understood which caused unexpected polymer degradation. Newer generation polymer insulators use modified designs and refined manufacturing techniques.

Furthermore, 230 kV polymer insulators are showing signs of deterioration. The deterioration appears due to corona activity on the insulator housing as a result of inadequately controlled electric fields. The degradation exposes the fiberglass rod to moisture which causes rapid deterioration leading to failure. The need to address the polymer insulator issue is underscored by two failures which occurred in October and November 2016. Both failures were a result of 230 kV polymer suspension insulators on C28C failing mechanically resulting in a conductor drop, as shown in the photos in Figure 9 and Figure 10. The dropped conductor did not contact the ground but was held in the structure window.

Figure 9 - Failed Polymer Insulator

Figure 10 - Failed Polymer Insulator

Since portions of Hydro One’s polymer insulator population are approaching their ESL, Hydro One retained EPRI to perform a detailed condition assessment of polymer insulators to assist Hydro One in determining the need and pacing of polymer insulator replacement. The condition assessment study focused on 87 polymer insulators from various manufactures with the service life range from 13 to 26 years. The following three insulator configurations form the scope of the study:

- 230 kV suspension with large corona rings;
- 230 kV suspension with either small (known as a “donut”) or no corona rings; and
- 115 kV dead end.

The condition of the insulators was evaluated through a series of tests which included:

- Visual Inspection;
- Hydrophobicity Assessment;

- Dye Penetration Testing;
- Water Vapor Ingress Testing; and
- Moisture Penetration Test of the End-fittings.

The following are the key findings of EPRI condition assessment analysis:

Visual inspection showed that:

- The 230 kV K-Line insulators with the 4-inch donut corona ring have an extremely high likelihood of electrical and/or mechanical failure due inadequate control of the electric field on the surface of the rubber housing at the line-end. The rubber housing at the line-end of these insulators has been severely eroded leading to exposure of the fiberglass rod. Such exposure of the rod will result in either mechanical or electrical failure with a high probability of the insulator parting and causing a conductor drop. Smaller (4-inch) corona rings were used on earlier generations of polymer insulators. When older polymer insulators were designed and manufactured, the long-term effects of electric fields were not well understood and it was standard practice to use small or no corona rings which caused unexpected polymer degradation. Newer generation polymer insulators use modified designs and refined manufacturing techniques.
- The 230 kV NGK insulators installed without corona rings are showing signs of serious deterioration of the line-end rubber housing and deterioration of the secondary seal. As such, they are considered to have a high risk of failure.
- The 230 kV NGK insulators installed with 8-inch corona rings are experiencing rubber housing damage at the line-end. Currently this deterioration does not appear overly serious, but it is not known how quickly the housing deterioration will progress. In the EPRI aging chamber and at one EPRI member utility site this deterioration did result in eventual failure.

Dye penetration testing showed that:

- Each of the insulator groups with the exception of the Ohio Brass insulators had a single insulator unable to meet the dye penetration test requirements.

Water vapor ingress testing showed that:

- Seven 230 kV K-Line insulators exhibited low resistance along their length after humidity conditioning. Of these seven, three had damage from power arcs and housing erosion which may explain their failure. The remaining four (all of which had 8-inch corona rings) will be further examined to determine the root cause of failure.

End-fitting moisture penetration tests showed that:

- All but three insulators passed the test. Of the failing three units, two have been in service for 26 and 27 years, and the third had major line-end rubber erosion and rod exposure.

At the conclusion of its condition assessment analysis, EPRI provided Hydro One with its recommendations. Key EPRI recommendations are as follows:

- All 230 kV K-Line insulators fitted with 4-inch donut corona rings should be removed from service as soon as possible since they pose a proven risk of immediate failure.
- All the 230 kV NGK insulators installed without corona rings should be removed from service as they are considered to be at high risk of failure.
- All the 230 kV Ohio Brass insulators installed without corona rings should be removed from service.
- The seven 230 kV K-Line insulators which failed the water vapor ingress test should be subjected to additional testing followed by dissection to quantify the degree of concern which should be associated with their failing the water vapor ingress test. This type of issue is generally associated with poor bonding between

the housing and the rod and is often a batch problem. Until the issue is understood, these insulators should not be maintained live without first checking their integrity with the EPRI-developed insulator tester.

Hydro One is using this information to optimize the overall replacement program with respect to the risk of in-service failure. Hydro One will be using the results and recommendations of the EPRI study to develop a polymer insulator replacement strategy. Hydro One will leverage current condition assessment and patrol programs to locate polymer insulators that were identified by EPRI and target them for replacement.

Investment Description

Transmission line insulators cannot be maintained or repaired to extend their service life; therefore, defective porcelain insulators and end-of-life polymer insulators are targeted for replacement as part of the Program. The defective porcelain insulators will be replaced with either glass type or porcelain type insulators. Replacements of defective porcelain insulators will be prioritized based on locations posing a higher public safety risk. The deteriorated polymer insulators will be replaced with either glass, polymer, or porcelain type insulators. Due to their longer ESL porcelain and glass are the preferred insulator types and are used wherever practical. However, polymer insulators will be considered when their material properties prove beneficial (i.e. in areas with high contamination).

Hydro One has approximately 34,000 circuit structures with defective porcelain insulators and roughly 15,000 have been identified as being on structures in publicly-accessible (critical) locations. Publicly-accessible (critical) structures include those located near roads, water railways, urban areas, golf courses, educational and health care facilities. As such, defective porcelain insulators posing a higher public safety risk (i.e. insulators in critical locations) are to be replaced by 2022 at a rate of approximately 3,700 circuit structures per year. Insulators in non-publicly- accessible areas will be replaced at an approximate rate of 3,450 circuit structures per year over a five-year period beginning in 2022.

Outcome

As a result of the Program, Hydro One will reduce public safety risk associated with insulator failures resulting in conductor drops and maintain system reliability by removing electrically and/or mechanically compromised insulators that may cause forced outages.

The following table presents anticipated benefits as a result of the Program in accordance with the OEB Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• Eliminate public safety risk associated with defective porcelain insulators • Maintain system and customer reliability by replacing defective and/or end-of-life insulators
Operational Effectiveness	• Maintain system and customer reliability by replacing defective and/or end-of-life insulators

C. EXPENDITURE PLAN

As discussed above, the Program is primarily needed to replace the defective COB and CP porcelain insulators that pose significant public safety and system reliability risks. Hydro One will strive to complete the Program in an effective and efficient way to minimize the cost of performing this sustainment task. The Program starts in January and ends in December of each of the test years.

Table 1 below presents forecasted costs for the Program. Costs for the Program are based on an average unit cost estimate calculated utilizing historical replacement costs. The replacement costs are influenced by the voltage level, structure type and accessibility.

Table 1 - Total Investment Cost

($ Millions)[1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	0.0	74.2	75.7	72.0	73.5	74.9	0.0	370.3
Less Removals	0.0	5.9	6.1	5.8	5.9	6.0	0.0	29.6
Gross Investment Cost	**0.0**	**68.3**	**69.7**	**66.3**	**67.6**	**68.9**	**0.0**	**340.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**68.3**	**69.7**	**66.3**	**67.6**	**68.9**	**0.0**	**340.7**

[1] *Due to the in-year nature of program investments, only 2020-2024 expenditures are shown*
[2] *Includes Overhead at current rates.*

D. ALTERNATIVES:

Hydro One considered the following alternatives before selecting the preferred undertaking:

Alternative 1: The "Do Nothing" - Reactive Replacement of Failed Insulators involves reactive replacement insulators as they fail. This alternative has been rejected due to the unacceptable public safety risk that may arise when a failure results in a conductor drop in a public area. Due to the continued degradation of these defective insulators the number of failures is expected to rise, negatively affecting safety, reliability and customer satisfaction. Furthermore, a systemic investment approach is needed to pace replacements to minimize the impact to customers and reliability.

Alternative 2: Planned Insulator Replacement is a recommended undertaking. This alternative involves planned replacement of defective porcelain and end-of-life polymer insulators prior to failure. This alternative is recommended as it will reduce the risk to public safety. In addition, it will enable investment pacing and outage planning to mitigate customer and reliability impacts.

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the insulator replacement program include: outage constraints, resource constraints, construction execution challenges, customer coordination, and procurement challenges. To address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize the loss of supply to the customer. The plan might include switching a customer to an alternative supply. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages.

SR-26 Transmission Line Emergency Restoration

Start Date:	Q1 2020	**Priority:**	High
In-Service Date:	Ongoing Program	**3Year Test Period Cost ($M):**	29.4
Trigger(s):	Corrective Maintenance, Safety, Reliability		
Outcomes:	Align with obligations with TSC; make safe and minimize public/employee safety risk, improve customer satisfaction by carrying out replacement in a timely manner to minimize unplanned customer interruptions; maintain transmission system reliability,		

A. OVERVIEW

Transmission Lines Emergency Replacement program is reactive in nature, mainly to provide an immediate response to an emergency situation or to prevent or minimize the effects of an emergency situation. This investment program funds the emergency replacements of transmission line components that have failed or identified to be in imminent danger of failure. A failed or deficient transmission line component may cause an impact on the transmission system that varies from being minor to significant. It poses safety risk as well as power delivery risk which might affect regional load flow limits and customer operations. As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards imposed by the Transmission System Code (“TSC”). This investment program ensures that Hydro One continues to comply with its commitment and legal obligations to mitigate safety, system reliability and environmental risks that an unforeseen failure might cause.

B. NEED AND OUTCOME

Investment Need

Hydro One’s transmission system extends to most of the province and operates in diverse geographic and climatic conditions. Hydro One operates transmission lines primarily at 500 kV, 230 kV and 115 kV, with minor lengths operating at 345 kV. These lines are used to transmit electric power to connected commercial and industrial customers, as well as to Local Distribution Companies (“LDC”) who in turn distribute the power to their end-use customers.

The majority of Hydro One's transmission system is composed of overhead lines, with a small portion being underground cables.

The major components of the overhead transmission lines system include conductors, steel and wood pole structures, foundations, insulators, shieldwire, switches and line hardware. Transmission line components may fail or be at risk of imminent danger of failure due to weather events, component deterioration, design deficiencies, vandalism, or accidents caused by public activity. Almost all of the transmission lines system is in public domain. The primary focus of this investment is to make safe of any emergent situation to ensure public and employee safety.

This investment is designed to maintain reliability and minimize power delivery impact. If any of the major transmission line components fail or are in imminent danger of failure, Hydro One must replace the asset as soon as possible in order to ensure public and employee safety and the integrity and reliability of the transmission system. When a transmission line component fails, the impact varies depending on where the component is and the redundancy level of the electrical configuration. In some cases, failed transmission line components may fall onto public areas such as road crossings and public or private properties, which could jeopardize public or employee safety, impacting power delivery and resulting in customer interruptions.

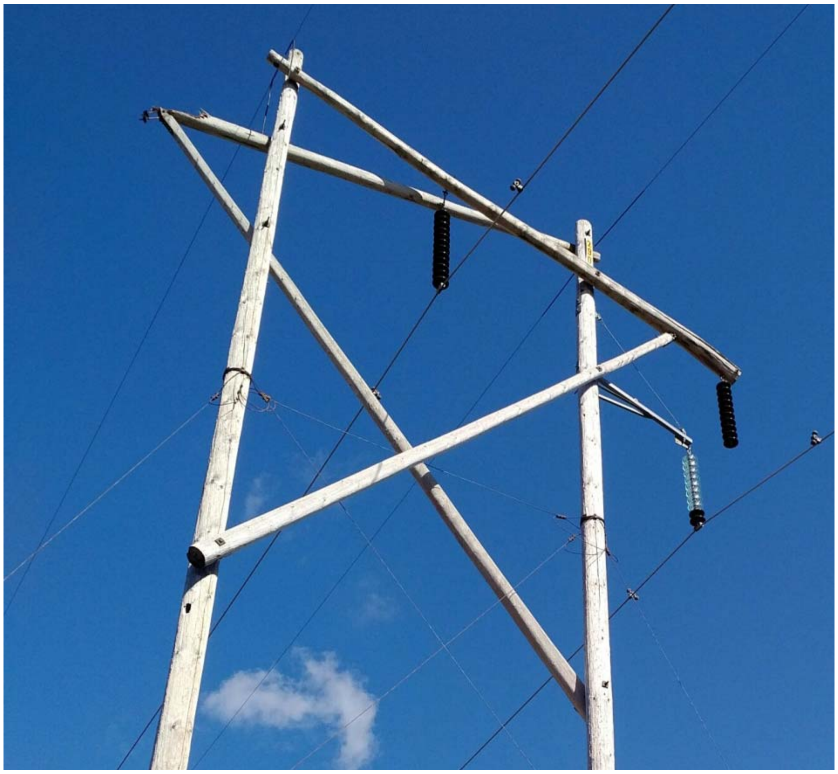
The OEB's TSC states a transmitter is required to take immediate action during an emergency or in order to prevent or minimize the effects of an emergency, to ensure public safety and to safeguard life, property and the environment as well as to protect the stability, reliability, and integrity of Hydro One's transmission facilities. As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards imposed by the TSC.

Investment Description

An emergency is defined as a structure or component that has failed or is at risk of imminent failure, where the failure could result in a serious public or employee safety hazard, circuit interruption and system reliability impact.

This investment is to fund the emergency replacements of failed or defective transmission line components, such as wood structures, cross-arms, towers, insulators, conductor, shieldwire and hardware. The reasons for transmission line components failure include, but are not limited to: normal weather conditions (i.e. lightning), severe weather events (i.e. tornado), deterioration, design deficiencies, vandalism, accidents caused by public activity, etc. In addition to structures and/or components that have failed as shown in the figures below, Hydro One must also respond to structures and components at risk of imminent failure that are identified through condition patrols. An example would be a wooden cross-arm or structure that has been damaged by lightning and poses a risk of failure. Such repairs are also considered an emergency.

Figure 1 - 2016 L20D (Kipling GS x Harmon Jct) steel structure failure due to windstorm



1 **Figure 2 – 2017 W71D (Lower Notch Jct x Widdifield SS) wood pole failure**

2 **Figure 3 – 2017 K2Z (Gosfield Wind CGS x Kingsville TS) wood arm at imminent danger**
3 **of failure**

Figure 4 – 2018 K2Z (Haycroft DS x Belle River Jct) Steel structure failure

Outcome

This program aims to:

- Mitigate safety risks by replacing failed overhead line components or components that are at risk of imminent failure.
- Maintain reliability of the transmission system by ensuring a timely response to replace failed overhead line components or components that are at risk of imminent failure.
- Satisfy Hydro One's commitments and obligations under the TSC

The following table presents anticipated benefits as a result of the investment program in accordance with the OEB's Renewed Regulatory Framework:

Customer Focus	• Improve customer satisfaction by minimizing interruptions and providing timely power restoration to customers
Operational Effectiveness	• Minimize public/safety risk and system reliability impact by repairing and/or replacing assets that failed or are at risk of imminent failure. • Comply with TSC obligations by providing safe and reliable electricity to Ontario electric consumers.

C. EXPENDITURE PLAN

Table 1 below presents forecasted planned expenditures for this investment program. The planned expenditures are based on historical spending. Historically the actual expenditure of this program is in line with the planned expenditure. For program work, cash flows are only shown for the five year period. Program work is started and completed in-year.

Table 1 - Total Investment Cost

($ Millions)[1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	0.0	10.4	10.7	10.9	11.1	11.3	0.0	54.3
Less Removals	0.0	0.8	0.9	0.9	0.9	0.9	0.0	4.3
Gross Investment Cost	**0.0**	**9.6**	**9.8**	**10.0**	**10.2**	**10.4**	**0.0**	**50.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**9.6**	**9.8**	**10.0**	**10.2**	**10.4**	**0.0**	**50.0**

[1] *Due to the in-year nature of program investments, only 2020-2024 expenditures are shown*
[2] *Includes Overhead at current rates.*

The average investment cost for this program over the five-year period is in line with the average five-year historical spending. Factors affecting this investment's costs are:

- The scope of the replacement work required to address the failure; and
- The type and quantity of the assets requiring replacement.

D. ALTERNATIVES

This investment program is non-discretionary and, as such, no alternatives have been considered. Failure to respond to an emergency or to prevent or minimize the effects of an emergency in a timely manner may jeopardize public and/or employee safety and violate the TSC. It might have a negatively impact on customer service.

E. EXECUTION RISK AND MITIGATION

The work that is part of this investment program is unplanned in nature and the risks of public/employee safety and potential customer supply interruptions are mitigated by timely response. However, there are risks to executing such unplanned work including the availability of resources and long lead times for the purchase of new transmission lines components.

SR-27 C5E/C7E Underground Cable Replacement

Start Date:	Q4 2016	**Priority:**	Medium
In-Service Date:	Q4 2024	**3 Year Test Period Cost ($M):**	62.8
Trigger(s):	Reliability, Environment		
Outcomes:	Maintains system and customer reliability by preventing cable failures associated with end of life equipment; eliminate the risk of obsolescence and supportability by replacing infrastructure with reduced production and manufacturer support; and eliminate environmental risk associated with oil leaks by replacing oil-filled cable.		

A. OVERVIEW

This high voltage underground cable project (the "Project") involves the replacement of oil-filled underground transmission cables on circuit C5E and C7E between Esplanade TS and Terauley TS. These underground cables provide a critical supply to Toronto's downtown core, particularly, hospitals, the University of Toronto, Toronto City Hall, financial district and tourist/entertainment areas. Based on a detailed asset condition assessment, these cables are in deteriorated condition and have reached their end of life. There is also a significant environmental risk associated with oil-filled cables. Cable breaches can be caused by failed or degraded components as well as by dig-ins from unauthorized excavation. The breach can result in the discharge of large volumes of oil into the surrounding environment which may cause significant environmental issues. Furthermore, there is an industry shift away from the use of oil-filled to cross-linked polyethylene ("XLPE") cable systems. This means that manufacturers have been reducing production and support for oil-filled cables. A limited number of manufacturers may lead to long delivery times and price increases. Due to their deteriorated and end of life condition, location and component obsolescence, these underground cables require immediate replacement. Hydro One has evaluated various alternatives for the Project, as described below, and concluded that replacing the deteriorated oil-filled underground transmission cables with the XLPE type cables is the most cost effective and efficient undertaking. The projected costs of the Project are estimated to be $62.8 million over the 2020-2022 Test period.

B. NEED AND OUTCOME

Investment Need

C5E and C7E from Esplanade TS to Terauley TS (7.2 circuit km) are 115 kV paper insulated low-pressure oil-filled underground transmission cables that provide a critical supply to Toronto’s downtown core and are partially routed along Lake Ontario. These circuits were put into service in 1959 and are in poor condition. Through a detailed condition assessment, Hydro One has determined that these underground circuits are at the end of life, and require immediate replacement. End of life means that an asset has a significant risk of failure, or loss of the ability to provide the intended functionality.

The cable jackets have been tested and were found to be in deteriorated condition necessitating the need for cable replacement. Deteriorated jackets can adversely affect cable performance by allowing circulating currents to flow leading to overheating damaging insulation, accelerated corrosion and oil leaks. Analysis of the paper insulation was performed and the results were indicative of thermal aging/degradation beyond what is normally seen in comparable Hydro One cables, by approximately 25%. Thermally degraded paper insulation can lead to cable failure during faults, resulting in prolonged circuit outages and negative environmental impact due a release of oil. Additionally, the oil pressure system has been the source of many nuisance oil leaks and is obsolete with few spare part suppliers. Due to their deteriorated condition, the risk of cable failure and oil leaks that may result in loss of supply and an adverse environmental impact will increase with time.

Interruption or failure of C5E and C7E can negatively impact power supply to Toronto Hospitals along University Ave., the University of Toronto, Toronto City Hall, financial district and tourist/entertainment areas. Further, approximately 2.6 circuit km of cable is directly buried under Queens Quay along the Lake Ontario. If a leak occurs along Queens Quay, it would likely be confined to the surrounding soil. However, if the leak is significant enough to contaminate ground and/or surface (Lake Ontario) water, the remediation will be very challenging and costly, requiring booms, wells, etc.

Investment Description

The Project will replace 7.2 circuit km of 115 kV low-pressure oil-fill underground cables that are at end of life with XLPE type cable. The replacement will encompass both C5E and C7E circuits from Esplanade to Terauley TS. The new underground cables may follow an alternate route allowing the existing circuits to remain in-service until the load can be transferred.

Outcome

As a result of the Project, Hydro One will maintain reliability and minimize future costs through the replacement of the end of life oil-filled cables on circuits C5E and C7E with modern XLPE cable. This will eliminate the risks to reliability associated with operating end of life assets, and eliminate the environmental and obsolescence risk associated with operating oil-filled cables. The removal of legacy oil-filled cables will also eliminate the preventative maintenance and repair costs associated with this legacy infrastructure.

The following table presents anticipated benefits as a result of the Project in accordance with the OEB's Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• Maintain system and customer reliability in downtown Toronto by replacing degraded end-of-life cable systems
Operational Effectiveness	• Maintain operational flexibility with supply to downtown Toronto
Public Policy Responsiveness	• Reduce risk of environmental contamination due to possible oil leaks

C. EXPENDITURE PLAN

Table 1 below presents forecasted costs for the Project. Costs for the Project are based on a budgetary estimate and will be significantly influenced by the final cable route. Costs up to 2022 are associated with the environmental assessment which includes public consultation and preliminary engineering and design. Costs in 2022-2024 are associated with the execution of the Project, which includes detailed design, construction and execution.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	4.5	2.1	30.0	31.0	32.3	29.3	0.0	129.3
Less Removals	0.0	0.0	0.1	0.2	0.2	0.1	0.0	0.6
Gross Investment Cost	**4.5**	**2.1**	**29.8**	**30.9**	**32.2**	**29.2**	**0.0**	**128.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**4.5**	**2.1**	**29.8**	**30.9**	**32.2**	**29.2**	**0.0**	**128.7**

[1] *Includes Overhead at current rates.*

D. ALTERNATIVES

Alternative 1: Reactive Replacement of Underground Cables is the "Do Nothing" alternative which means Hydro One will continue to operate and maintain the existing C5E and C7E cables and replace them upon failure. This alternative has been considered and has been rejected as failure of these cables will result in prolonged circuit outages, potential customer interruptions, loss of redundant supply negatively affecting operational flexibility, and potentially oil leaks requiring environmental remediation.

Alternative 2: Planned Replacement of Underground Cables is a preferred undertaking. This alternative involves planned replacement of 7.2 circuit km of deteriorated end-of-life 115 kV low-pressure oil-filled underground transmission cable with oil-free XLPE cable between Esplanade and Terauley TS. Due to their deteriorated condition and the increased risk of cable failure and oil leaks, planned replacement will mitigate the risk to reliability, loss of supply and adverse environmental impact.

E. EXECUTION RISK AND MITIGATION

The primary risk to the Project completion will be the final cable route. Multiple potential routes are being evaluated and include open-cut and tunneling options. Open-cut construction is significantly more impactful to the public (i.e. traffic, business, etc.), will likely face public opposition and may not be feasible due to underground congestion, whereas the tunnel option is less impactful to the public but may be more costly. The final route will be selected during detailed estimation and will be influenced by a technical feasibility study, environmental assessment, public consultations and economics. An execution risk assessment workshop will be completed as part of the detailed estimating for this project to identify and mitigate potential project risks.

SR-28 Fibre Optic Infrastructure Development Projects

Start Date:	Q1 2021	**Priority:**	Medium
In-Service Date:	Q4 2025	**3 Year Test Period Cost ($M):**	14.9
Trigger(s):	System Renewal, Strategic		
Outcomes:	Maintain Reliability		

A. OVERVIEW

Hydro One utilizes fibre optic cable infrastructure including Hydro One owned and operated aerial fibre optic cables, as well as fibre strands acquired through indefeasible right of use (“IRU”) agreements from third-party telecom providers. The latter fibre infrastructures will be referred to in this document as “third-party” fibre(s). An IRU is an exclusive and irrevocable right of use granted by the owner of a communications system to a customer or user of that system. Instances of past failures of third-party fibres have compromised Hydro One's ability to reliably operate the transmission system. Historical failure incidents from 2009-2017 on Hydro One SONET network show that third-party fibres are three to four times more likely to fail than Hydro One’s own Optical Ground Wire (“OPGW”) fibres.

In order to maintain the reliability of the transmission system, Hydro One’s current asset management strategy is to (i) identify opportunities and gradually replace the use of third-party fibres that are subject to higher failure risk with the use of Hydro One’s OPGW fibres to the extent possible; and (ii) increase the existing OPGW footprint in order to extend fibre coverage to Hydro One facilities that currently experience less reliable leased services from telecom service providers (“Telco”) To this end, Hydro One has proactively leveraged and installation of OPGW as part of transmission line shieldwire replacements and line refurbishment projects where economically feasible. Because these projects are driven by EOL replacements, the OPGW installation may not provide complete end-to-end fibre connectivity. This project is designed to complement the aforementioned initiative and build remaining OPGW infrastructure such that an end-to-end fibre-based telecom path can be constructed.

B. NEED AND OUTCOME

Investment Need

This investment is needed to address the reliability risks posed by failing, leased third party fibre as well as leased circuits provided by Telcos.

Based on the Synchronous Optical Network ("SONET") technology, Hydro One's communication network is primarily utilized by protection systems and SCADA monitoring systems, as well as for communicating non-operational data, business data, voice, and security information. It is also used for backhaul communication for the provincial mobile radio system. The current network topology connecting stations is in the form of a ring to provide redundant communication links that can stretch up to hundreds of kilometers long across the province.

These SONET rings provide robust and reliable communication between transmission stations because of the reliable fibre optic cable infrastructure and network configuration that provide redundancy paths for communications. Hydro One utilizes approximately 3,800 kilometers of fibre optic cable infrastructure including Hydro One owned and operated aerial fibre optic cables as well as fibre strands acquired through IRUs. Aerial fibre optic cable is primarily comprised of (i) OPGW technology with strands of fibre embedded inside of the shieldwire mounted on top of high-voltage transmission structures and (ii) All-Dielectric Self-Supporting ("ADSS") fibre cable that is attached to towers or poles typically below the phase conductors, with a small share being attached to low-voltage wood poles located along roadways and/or railways.

Hydro One also utilizes a large number of leased metallic copper-based circuits from Telcos for communication-aided protection schemes at many transmission stations. Due to the current age and obsolescence of these communication circuits they have become failure-prone and hence not desirable for transmission protection, control and monitoring applications. Furthermore, Telcos intend to upgrade these legacy copper-based systems to fully digital and fibre-based facilities.

As part of Hydro One's proposed investment for Fibre Optic Infrastructure Development, the following four projects are identified for the planning period, as further described in the next section:

- Ottawa Ring 9 Fibre Infrastructure Development
- Martindale TS by Widdifield SS OPGW link
- Martindale TS by Algoma TS OPGW link
- Claireville TS by Beaverton TS OPGW link

Investment Description

The projects described herein aim to maintain or restore reliability of Hydro One's existing power system telecom network by placing replacing the use of third-party fibres and Telco metallic cable facilities with the use of highly-reliable OPGW fibre.

Through the Ottawa Ring 9 fibre infrastructure project, Hydro One plans to place 130 km of new OPGW fibre to connect Merivale TS to South March TS, Chats Falls SS, Arnprior TS, Barret Chute TS, and Stewartville TS. This project will allow the legacy Telco metallic circuits that provided communications for protection and SCADA systems to be replaced with modern, fibre-based Hydro One-owned telecom facilities. The expected benefits will be improvement of communications reliability for protection and SCADA applications, avoiding the need for upgrades to Telco entrances at these stations, lower OM&A leased circuit costs and avoiding upgrades to Power Line Carrier ("PLC") systems in Eastern Ontario as they approach end-of-life.

Taking advantage of synergies by leveraging the transmission line shieldwire replacement program, Hydro One will be installing 80 km of OPGW between Martindale

TS and Widdifield TS. The Martindale TS by Widdifield SS OPGW link project covers installation of the remaining 56 km of OPGW on line H24S East of Martindale TS, towards Widdifield TS. Once the 80 km and 56 km paths are both completed, the end-to-end fibre path from Martindale to Widdifield (between Sudbury and North Bay) will allow the replacement of failure-prone third party IRU fibre on Ring 7 with Hydro One-owned highly reliable fibre facilities.

The Martindale TS by Algoma TS OPGW link project aims to provide complete the end-to-end fibre infrastructure between the two stations that already has certain sections with OPGW installed under the shieldwire replacement program. The existing power system telecom link from Martindale by Algoma is on a third-party fibre provider installed on wood pole in the area. Historically, this link has experienced one of the highest rates of failures on Hydro One’s power system telecom network. This project will build the remaining sections of OPGW (approximately 95 km) on line S2B in this area to fill in the gaps and complete an end-to-end fibre path in order to restore the communication reliability on SONET Ring 7.

Claireville TS by Beaverton TS OPGW link project aims to install approximately 105 km of OPGW fibres on lines H82V/H83V and B88H/B89H from Claireville TS to Brown Hill TS and on lines M80B/M81B from Brownhill TS to Beaverton TS. The communication for these 230kV Bulk Power System lines has experienced reliability degradation due to the high failure rates of Telco legacy metallic circuits. The project is intended to restore the reliability of existing power system telecom services by installing Hydro One owned fibre facilities to replace Telco legacy metallic-based communication circuits.

A summary of expenditures for the four projects described above is provided in Table 1:

Table 1 - Project Summary ($ millions)

Circuits	Project Description	2020-2024 Net Expenditures	Project In-Service Year
M32S, C3S, M31A, W6CS, W3B	Ottawa Ring 9 Fibre Infrastructure Development	8.6	2021
H24S	Martindale TS by Widdifield SS OPGW link	5.1	2022
S2B	Martindale TS by Algoma TS OPGW link	7.4	2025
H82V/H83V, B88H/B89H, M80B, M81B	Claireville TS by Beaverton TS OPGW link	9.7	2025

Outcome

The following table presents the anticipated benefits of the Program in accordance with the OEB RRFE framework:

Customer Focus	• Maintain system reliability and reduce risk of outages that affect customers.
Operational Effectiveness	• Maintain reliability of the transmission system through ensuring a reliable communication network by replacing poor performing and degraded third party fibre cables with Hydro One-owned OPGW cable to the extent possible.
Public Policy Responsiveness	• Hydro One is obligated to build and maintain a reliable and redundant communication/protection system (including to address the reliability issues associated with third-party fibre cables) to ensure compliance with applicable performance standards under NERC TPL-001.
Financial Performance	• Mitigate OM&A costs associated with the relative high failure rates of third-party fibre cables.

C. EXPENDITURE PLAN

Table 2 below presents the forecasted costs of this investment. These costs are based on estimated unit costs, which are derived from similar historical projects.

"Previous years" costs are associated with development of a detailed execution plan for the Ottawa Ring 9 Fibre Infrastructure Development. The costs for that project in the subsequent years are work execution costs, with the bulk of engineering, procurement and construction work to occur in 2020 and 2021.

Year 2020 costs are associated with the development of a detailed execution plan for the Martindale TS by Widdifield SS OPGW link project. The bulk of the engineering and construction work for this project will occur in 2021 with project completion expected in 2022.

Project year 2021 costs are associated with the development of a detailed execution plan for Martindale TS by Algoma TS OPGW link project. The bulk of the engineering and construction work for this project will occur in 2022 and 2023, taking advantage of lines construction crews that will already be in the area for other planned work.

Claireville TS by Beaverton TS OPGW link project will start in 2022. 2022 costs are associated with the development of a detailed execution plan and budget for this project.

The bulk of the engineering, procurement and construction work for this project will occur in 2023 and 2024, with project completion expected in 2025.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	1.2	5.5	7.8	2.3	6.5	10.1	4.7	38.1
Less Removals	0.0	0.2	0.3	0.1	0.3	0.4	0.2	1.5
Gross Investment Cost	**1.2**	**5.3**	**7.5**	**2.2**	**6.2**	**9.7**	**4.5**	**36.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.2**	**5.3**	**7.5**	**2.2**	**6.2**	**9.7**	**4.5**	**36.5**

[1] *Includes overhead at current rates.*

D. ALTERNATIVES

Alternative 1: Status Quo "Do Nothing" Option

This alternative is not recommended as the reliability degradation of Hydro One's power system telecom network will directly impact the operation of the transmission system. Hydro One cannot continue to rely on third-party fibre facilities and legacy Telco metallic facilities for its long-term power system telecom needs, due to the high failure rates associated with these facilities. Such failures result in loss of redundancy and loss of communication of protection systems, adversely impacting the reliability of the transmission system and delivery of service to customers.

Alternative 2: "Fibre Optic Infrastructure Development Projects"

This alternative is preferred as it will maintain or restore robust and reliable communications through Hydro One's power system telecom network. The installation of new OPGW fibres to replace the use of Telco metallic cables that currently serve various protection and SCADA facilities. It will also allow Hydro One to avoid the need to upgrade to Telco entrances and existing standalone communication systems.

Additional OPGW investments in areas to the East and West of Martindale TS will allow Hydro One to complete certain end-to-end fibre optic paths by filling in the gaps between the OPGW fibres that are already being installed as part of Hydro One's shieldwire replacement project. This will enable Hydro One to remove certain highly unreliable third-party fibres in these areas and replace them with Hydro One-owned facilities, thus avoiding the costs that are otherwise required for leasing or renewing the use of third-party fibre facilities.

E. EXECUTION RISK AND MITIGATION

Execution risks include potential delays in required circuit outages to carry out replacement work. Hydro One will manage and stage the projects under this investment to ensure that outages are available in time. The availability of resources and other competing projects requiring similar resources are also a risk to project completion. Hydro One will develop a detailed project and resource plan in order to ensure resources are available.

SR-29 Physical Security ISL Application Replacement

Start Date:	Q1 2018	**Priority: High**	
In-Service Date:	Q2 2021	**3 Year Test Period Cost ($M):**	6.1
Trigger(s): NERC compliance, reliability			
Outcomes:	**NERC Compliance**		

A. OVERVIEW

This investment entails the implementation of a new integrated physical security access control and video monitoring application, which is required to mitigate potential vulnerability and compatibility issues, and maintain compliance with the North American Electric Reliability Corporation's ("NERC") requirements for Critical Infrastructure Protection ("CIP" (CIP-006: Physical Security of Bulk Electric System ("BES") Cyber Systems).

B. NEED AND OUTCOME

Investment Need

Hydro One's current physical security monitoring system is comprised of two, non-integrated, components; Intercon Security Ltd. ("ISL") access control and IndigoVision video monitoring. The former is based on a legacy application (ISL10000) that manages and controls physical access and monitoring at 135 facilities; whereas IndigoVision is used to manage camera and recorded video surveillance at 107 facilities.

The ISL access control system is end of life, resulting in limitations in terms of compatibility with newer access control devices (such as card readers) for physical access monitoring. The ISL application and the supporting hardware are no longer being manufactured and will only be supported on a best effort by Johnson Controls until December 2020.

The current IndigoVision software and approximately 80 per cent of the associated surveillance hardware used by Hydro One will no longer be vendor-supported after December 2019.

Investment Description

The ISL and IndigoVision systems are a foundational component of Hydro One's NERC CIP security program at high impact control centers and medium and low impact[1] transmission stations (approximately 75 to 80 stations). The–NERC CIP-006 standard requires full time access control and monitoring of each Physical Security Perimeter ("PSP")[2]. Johnson Controls currently maintains a small inventory of replacement parts. Therefore, a failure of ISL or IndigoVision equipment or supporting software will require Hydro One Networks to secure full time (24x7) security personnel coverage until a solution can be implemented. Once the inventory of replacement parts is depleted, spare parts required to service and maintain the ISL and IndigoVision systems would need to come from removed hardware, as facilities migrated to the new system (as described below) over the next three years until all stations are converted.

In conjunction with Supply Chain, Hydro One Security Operations developed a scope of work for a competitive tendering physical security systems assessment and recommendations.

The Genetec Security Centre solution was selected as it was the best fit for Hydro One's current and future system architecture, complies with NERC CIP requirements, and it is used across the Canadian electric industry and by other large corporations.

[1] High, Medium, and Low impact as defined in NERC CIP-002.
[2] The PSP is the physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.

The proposed investment will include the following activities:

- Install new central physical security monitoring system application at the Ontario Grid Control Centre ("OGCC") (primary) and at the Back Up Control Centre ("BUCC") (backup).
- Replace existing site access controllers with Genetec controllers at 135 existing Hydro One sites (high/medium/low impact and service centers) and upgrade the older card readers at approximately 70 of the 135 sites to ensure compatibility with the new physical security monitoring system.
- Replace the current unsupported IndigoVision video hardware (network video recorders and cameras) at 135 sites.
- Install a new Virtual Private Network ("VPN") to provide full control of user access to the Video Surveillance Telecom System security network.
- Create a physical security operations library database of systems, devices and capabilities (including features and functionality) for future competitive bidding process.
- Update site drawings.
- Integrate the current Hydro One employee Identity Management on-boarding / off-boarding processes to ensure timely revocation in compliance with CIP-006.
- Decommission the current physical security access control and video system, and archive relevant data in compliance with CIP-006.
- Replace the current Kantech access control systems at Hydro One Sault Ste. Marie's (HOSSM) 6 facilities[3].

[3] HOSSM as a subsidiary of Hydro One Inc. and is currently being monitored internally by HOSSM. Replacement of the existing access control systems at HOSSM creates a single, integrated system to monitor, support, and maintain.

Outcome

The key outcomes and benefits that are expected to result from this investment are as follows:

- The Genetec system provides integrated access control and video monitoring, therefore Hydro One will not be required to upgrade the IndigoVision software which is estimated to cost $0.7 million. This will replace the IndigoVision software.
- Provides an integrated platform interface for all of Hydro One's security operations components (e.g. access card, CCTV/cameras, intercom, key-lock, gate control) using current physical security encrypted protocols).
- Ensures Hydro One maintains compliance with NERC CIP-006, including being able to control and monitor each Physical Access Point[4] ("PAP") into for unauthorized access and issue an alert in response to detected unauthorized access within 15 minutes of detection as required under NERC CIP-006.
- Mitigate legal, financial, reputational and compliance risks as the current legacy system becomes obsolete and no is longer adequately protected from security vulnerabilities and device failures.
- New installed hardware will be under warranty (access control hardware for two years and video recording hardware for three years), ~~,~~ thus reducing Operations, Maintenance & Administration ("OM&A") cost exposure for any replacements related to device failures in the near term.
- Genetec's non-propriety system will provide Hydro One with additional flexibility and options with respect to third-party monitoring solutions, including the ability to conduct a competitive bidding process in June 2021 when the current contract with Johnson Controls expires.

[4] A Physical Access Point ("PAP") is any opening that can be used to physically gain unauthorized access into a PSP.

The following table presents anticipated benefits as a result of the project in accordance with the OEB RRF framework:

Public Policy Responsiveness	• Ensure Hydro One's compliance with NERC CIP-006. • Reliability

C. EXPENDITURE PLAN

The solution had to meet the system and feature functionality requirements as well as NERC compliance reporting. Genetec Security Centre is the best fit for Hydro One's current system architecture and future needs. Genetec Security Centre offers pass-card access control that is an open platform and non-proprietary which facilitates independence from a single vendor for support as well as the ability to integrate easily with many other physical security technologies (e.g., cameras, radar systems etc.). The system offers a truly unified platform single interface for all the Hydro One Security Operations (pass-card, CCTV, intercom, key-lock, gate control). The installation of the new video system can be accomplished at the same time as the access control system representing an estimated $0.5M in labor savings. The roll out schedule will take into consideration implementing stations within a geographical area and work in conjunction with CIP-014 Physical Security Project to minimize resource effort.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	12.8	5.0	1.1	0.0	0.0	0.0	0.0	18.9
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**12.8**	**5.0**	**1.1**	**0.0**	**0.0**	**0.0**	**0.0**	**18.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**12.8**	**5.0**	**1.1**	**0.0**	**0.0**	**0.0**	**0.0**	**18.9**

[1] *Includes overhead at current rates.*

D. ALTERNATIVES

This is a non-discretionary investment that is required to ensure ongoing compliance with NERC requirements. Doing nothing is not recommended as the current physical security monitoring system is at end of life of vendor support and requires an upgrade to maintain compliance with NERC CIP-006

Hydro One evaluated two systems; the Genetec System met Hydro One requirements, while the other system did not offer Hydro One the same capabilities.

E. EXECUTION RISK AND MITIGATION

No significant risks identified. The risk to this project includes scheduling of resources to complete all the necessary work. This risk is mitigated through coordinated planning and scheduling.

SS-01 Lennox TS: Install 500kV Shunt Reactors

Start Date:	Q3 2018	**Priority:**	High
In-Service Date:	Q4 2020	**3 Year Test Period Gross Cost ($M):**	32.3
Trigger(s): Third Party Request, Operating Reliability			
Outcomes: Maintain acceptable voltages on the transmission system.			

A. NEED AND OUTCOME

Investment Need

This investment is in response to the IESO's request to Hydro One dated March 8, 2017 (see Appendix "A" below) to undertake the installation of two line-connected shunt reactors (each rated at 125MVAR at 500kV) on two of the 500kV circuits from Lennox TS to Bowmanville SS.

The IESO has observed low transfers across the transmission path from Bowmanville SS to Hawthorne TS, under light load conditions, that frequently result in high voltages. In order to maintain voltages within acceptable limits, the IESO has been temporarily removing one of the 500kV Lennox TS to Bowmanville SS circuits from service to reduce voltages.

The IESO expects that this situation will be further exacerbated following the retirement of Pickering NGS, requiring more than one of the 500kV Lennox TS to Bowmanville SS circuits to be taken out of service unless additional reactive control devices are installed. In response to this issue the IESO has identified the need to install shunt reactors at Lennox TS. These facilities will permit the IESO to manage the voltages on the transmission system within acceptable limits.

Not proceeding with this investment would result in inadequate voltage control that would negatively impact system reliability. This project is assigned a High Priority in order to remain compliant with the IESO's voltage criteria.

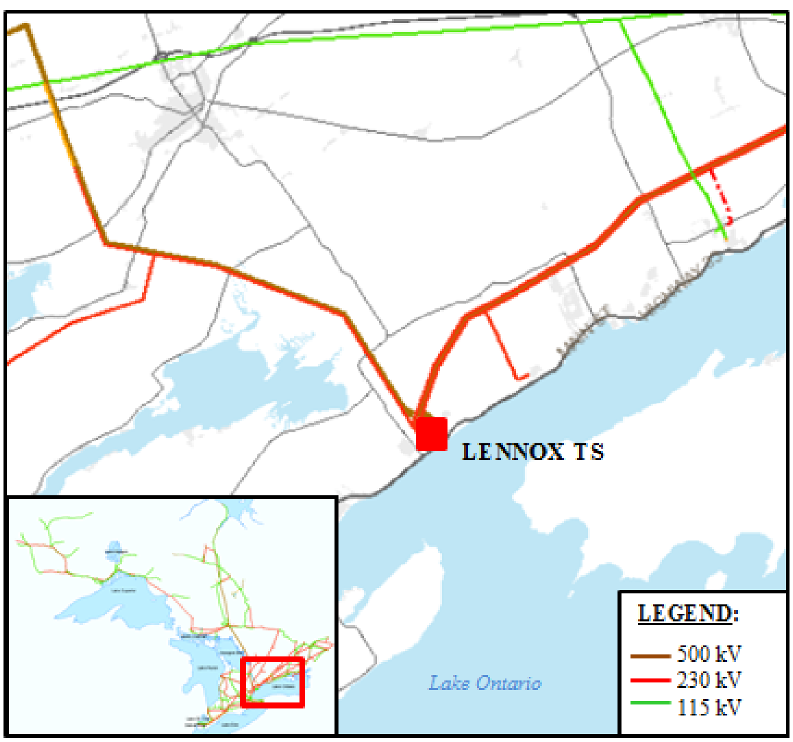
Investment Description

In response to the request from the IESO to provide additional reactive power absorption capability, the proposed project involves the:

- Installation of two 500kV line-connected reactors (each rated at 125MVAR at 500kV) at Lennox TS and connect each reactor to one of the 500kV Lennox TS to Bowmanville SS circuits;
- Installation of two 500kV breakers to connect reactors to the 500kV circuits; and
- Modification of the protection and control facilities at Bowmanville SS and Lennox TS to incorporate the new reactors.

The IESO indicated that the system enhancements that form part of this investment are required as soon as possible. Hydro One has placed a High Priority on this investment to address this requirement.

A map showing the project location is provided below.



Outcomes

This investment will result in maintaining acceptable voltages in order to ensure system reliability.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Improve reliability of the bulk transmission system.
Operational Effectiveness	• Maintain acceptable voltage limits to eliminate the risk associated with switching 500kV circuits for voltage control.
Public Policy Responsiveness	• Maintain voltage between the maximum and minimum range specified by the IESO Market Rules.

B. EXPENDITURE PLAN

The project costs, presented in the table below, will be recovered from the network rate pool as these 500kV facilities are network assets and thus no capital contribution is required from customers.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	16.2	32.3	0.0	0.0	0.0	0.0	0.0	48.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**16.2**	**32.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**48.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**16.2**	**32.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**48.5**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

Hydro One worked with the IESO to consider a number of options to address the high voltage concerns described above. The three alternatives below describe the technically feasible options that have been assessed by Hydro One and the IESO.

- Alternative 1: Install four line shunt reactors at Lennox TS; with a reactor connected to each one of the 500kV Lennox TS to Bowmanville SS circuits.

- Alternative 2: Install two shunt reactors at Lennox TS; where each reactor is connected to one of the 500kV buses at Lennox TS.

- Alternative 3 (Recommended): Install two line shunt reactors at Lennox TS; with a reactor connected to only two of the 500kV Lennox TS to Bowmanville SS circuits.

Alternatives 1 to 3 would provide the additional reactive power absorption capability required; however Alternative 3 met the required need at the lowest cost. As such, Alternative 3 was selected as the recommended alternative.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as: outage availability that is required for the work to be executed. These risks will be mitigated by setting a schedule that aligns with the outage availability.

APPENDIX "A" - Letter from the IESO to Hydro One

ieso
Connecting Today.
Powering Tomorrow.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

March 8, 2017

Mr. Bing Young
Director, Transmission System Development
Hydro One Networks
483 Bay Street,
Toronto, Ontario M5G 2P5

Dear Bing,

Re: Installation of 500 kV Reactors at Lennox TS

The purpose of this letter is to request that Hydro One Networks undertake the installation of two line-connected shunt reactors (each rated at 125 Mvar at 500 kV) on two of the 500 kV circuits from Lennox TS to Bowmanville SS.

Having these facilities will permit the IESO to better manage the high voltage events which are occurring increasingly frequently on the transmission network in eastern Ontario and the Greater Toronto Area (GTA). Ever since this high voltage concern was first observed a few years ago, staff at Hydro One Networks and the IESO have worked together to develop this recommended solution, which is described in more detail below.

Background

Over the past several years, high voltages were observed on the transmission system in eastern Ontario and the GTA, which were caused by low transfer levels across the 500 kV transmission system from Bowmanville SS to Hawthorne TS. This 500 kV transmission system consists of four 500 kV circuits from Bowmanville SS to Lennox TS and two 500 kV circuits from Lennox TS to Hawthorne TS, which can produce a significant level of capacitive injection into the 500 kV system when it is lightly loaded and raise voltages unless adequately compensated.

The resources normally available to provide reactive power compensation and control voltages in eastern Ontario and the GTA include shunt reactors connected to the tertiary winding of the autotransformers at Lennox TS and Hawthorne TS, and the generators at the two nuclear stations – Pickering NGS and Darlington NGS. However, especially when some of these facilities are not available, such as during planned or forced outages, these resources are not always sufficient to maintain voltages below acceptable limits. As a result, the IESO is often required to temporarily remove Bowmanville to Lennox 500 kV circuits from service to reduce voltages. For example, in 2016 a Bowmanville to Lennox 500 kV circuit was taken out of service for voltage control for ~ 200 days.

Following the planned retirement of all of the generating units at Pickering NGS between 2022 and 2024, there will be fewer reactive absorption facilities available to manage voltages, which would worsen the problem. Studies showed that after the retirement of the Pickering units, high voltage concerns would occur when the transfers across the Bowmanville by Lennox 500 kV circuits are below 700 MW eastwards and 500 MW westwards. These flow levels are expected to occur ~300 days per year after Pickering retires. Without additional reactive compensation or voltage control devices, to manage these high voltage events it is expected that more than one 500 kV circuit would need to be removed from service.

Ontario's 500 kV network is the backbone of the transmission system. It was designed with a level of redundancy that allows the system to withstand and quickly recover from contingencies on the power system. Switching out 500 kV circuits to manage voltages reduces this redundancy and could, therefore, delay the restoration of the power system to a secure operating state following a disturbance. This is because it would take time to reconnect the circuit following the disturbance and switching equipment could fail when attempting to reconnect the circuit.

Another challenge with relying on switching out 500 kV circuits for voltage control is that it may not always be possible to switch out the Bowmanville to Lennox 500 kV circuits. Those 500 kV circuits terminate at the Bowmanville 500 kV bus, where the Darlington nuclear units are also connected and there may be situations where switching in the Bowmanville station is restricted.

Therefore, new reactive power compensation and/or voltage control facilities are needed in the area.

Working with Hydro One, a number of options were considered for addressing the high voltage concerns described above. The table below shows the technically feasible options that were assessed.

Option	Description	Cost
1	Install four line shunt reactors at Lennox TS	$92M
2	Install two line shunt reactors at Lennox TS	$66M
3	Install two shunt reactors on the Lennox 500 kV bus	$76M

A number of other options were considered, such as connecting reactors to the tertiary windings of the Cherrywood TS and Parkway TS autotransformers, however they were ruled out because they did not address the concern.

Required System Enhancements

Based on technical analysis performed by the IESO, and budgetary cost estimates received from Hydro One on November 30th, 2016, the recommended option is:

- Install two 500 kV line-connected reactors (each rated at 125 Mvar at 500 kV) at Lennox TS and connect each reactor to one of the circuits of each of the Bowmanville × Lennox 500 kV lines.
- To maintain the present Flow-into-Ottawa (FIO) operating limit, it may be necessary to include the two 500 kV line-connected reactors in an existing Remedial Action Scheme (most probably the Lennox Reactor Switching Scheme). The details would be determined through the Connection Assessment and Approval (CAA) process.

The IESO requests that Hydro One undertake the installation of these facilities. Since there is a need today, these system enhancements are required as soon as possible. Our understanding is that these facilities will be in-service by Q4 2020 at a cost of ~ $66 million.

We look forward to working with Hydro One in the related Connection Assessment and Approval (CAA) process for this work and provide any assistance in the approvals processes associated with these facilities.

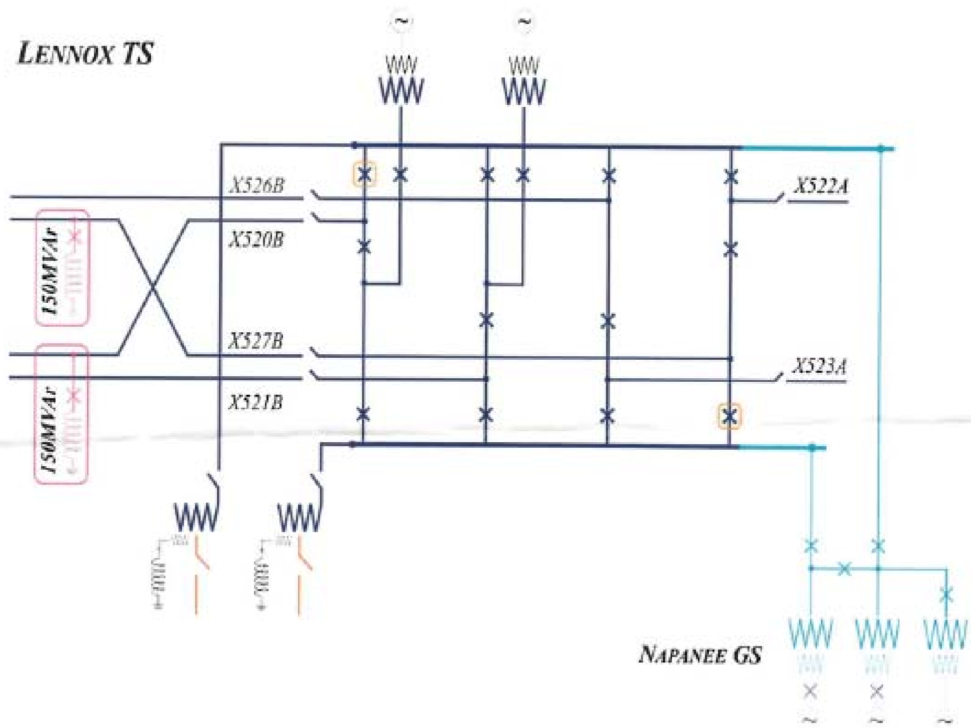
Yours truly,

R. F. Chow

R. F. Chow
Director, Transmission Integration
Independent Electricity System Operator (IESO)

CC:
Farooq Qureshy – Transmission Planning Manager, Hydro One
Michael Lyle –Vice President Planning, Legal, Indigenous Relations & Regulatory Affairs
Leonard Kula – Vice President, Market & System Operations & Chief Operating Officer
Joe Toneguzzo – Director, Transmission Integration
Ahmed Maria – Senior Manager, Transmission Integration
David Short – (Acting) Director, Power System Assessments
Peter Drury – Senior Planner
Kun Xiong - Planner

Single Line Diagram of Required Facilities



SS-02 Wataynikaneyap Power LP Line to Pickle Lake Connection

Start Date:	Q2 2019	**Priority:**	High
In-Service Date:	Q4 2020	**3 Year Test Period Gross Cost ($M):**	26.4
Trigger(s): Third Party Request, Political Commitment			
Outcomes: Connect the Wataynikaneyap Power's new line to the transmission system by installing a new switching station at Pickle Lake and a junction at Dinorwic.			

A. NEED AND OUTCOME

Investment Need

This investment is to facilitate the connection of the Wataynikaneyap Power LP ("WPLP") Line to the Hydro One's transmission system at Dinorwic and Pickle Lake.

In both the 2013 and 2017 Long-Term Energy Plan ("LTEP"), the provincial government identified that connecting remote North-Western First Nation communities is a priority for the Government of Ontario. The government also confirmed that a new line to Pickle Lake would, among other things, provide increased capacity to connect remote communities north of Pickle Lake and, for that reason, that line is a key priority for Ontario.

On July 20, 2016, the Lieutenant Governor in Council made an order declaring that the construction of electricity transmission lines to Pickle Lake and extending north from Red Lake and Pickle Lake required to connect sixteen named remote First Nation communities (Remote Communities) to the provincial electricity grid are needed as priority projects. In its Order in Council, the Lieutenant Governor in Council required WPLP to undertake the development of the line to Pickle Lake and the Remotes Connection Project.

In light of the foregoing and pursuant to its Transmission License, Hydro One is required to make this connection. This investment has been assigned a High Priority as the WPLP Line to Pickle Lake and the Remotes Connection Project has been designated as priority project.

In addition to providing capacity for connection of remote communities and new mining developments, the project also improves the reliability for the customers connected to the 115kV circuit (E1C), including Musselwhite Mine and distribution customers, as well as increases the supply capacity for the North of Dryden, by creating a second supply point at Pickle Lake.

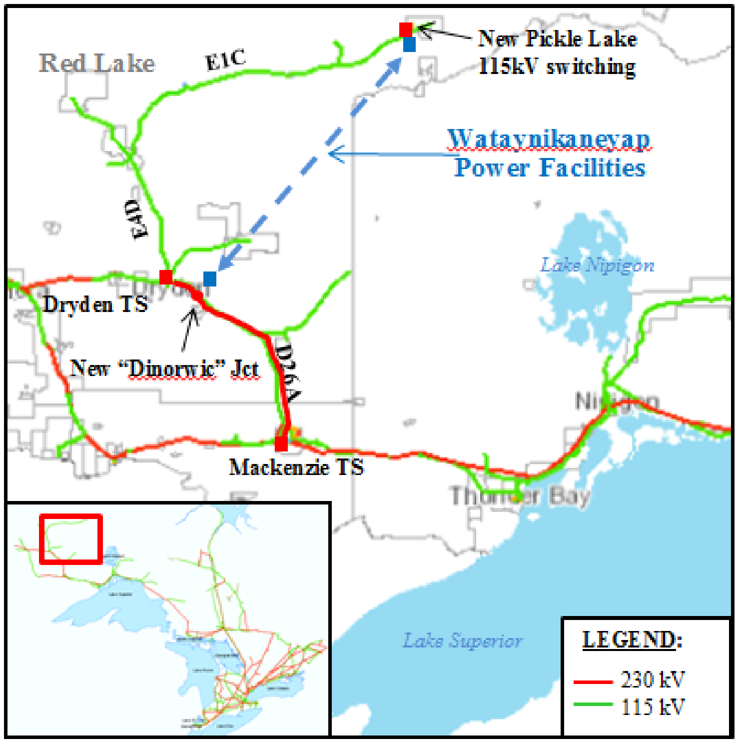
Investment Description

The proposed project to connect the WPLP's new 230kV line and 230/115kV transformer station to Hydro One facilities involves:

- Connection of the WPLP's 230kV Dinorwic switching station to Hydro One's existing 230kV circuit (D26A). This connection will require the construction of a new 230kV "Dinorwic Junction" with two motorized switches; and
- Connection of the WPLP's 230/115kV transformer station to Hydro One's existing 115kV circuit (E1C) at Pickle Lake. This connection will require the construction of a new 115kV switching station (in proximity to the WPLP transformer station) as well as protection and control modifications to incorporate the new line.

WPLP have applied for "Leave to Construct" approval for the WPLP transmission facilities (EB-2018-0190) under Section 92 of the *Ontario Energy Board Act*. The application contains a description of Hydro One's new facilities to connect the WPLP facilities to the grid.

A map showing the project location is provided below.



Outcomes

This investment will provide the required connection of the WPLP facilities to the Hydro One transmission system thereby facilitating supply of electric power to remote First Nations communities.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Ensure adequate supply capacity for the existing and new customers. • Improve reliability for the existing customers.
Operational Effectiveness	• Improve outage management for the existing radial connections.
Public Policy Responsiveness	• Comply with the Government policy of providing electric supply connection to remote First Nations communities. • Comply with Hydro One's obligation under its Transmission License to connect neighboring transmitters and provide customers with non-discriminatory access.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, presented in the table below, will be recovered from the network rate pool as these facilities are network assets and thus no capital contribution is required from customers.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	3.4	24.9	1.5	0.0	0.0	0.0	0.0	29.8
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**3.4**	**24.9**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**29.8**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.4**	**24.9**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**29.8**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

No alternative was considered, as this investment is in response to WPLP's plans for connection of their facilities at Pickle Lake and Dinorwic.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as: the outage availability that is required for the work to be completed. Also, delays in WPLP obtaining "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act* or Environmental Assessment approvals might impact this project completion. These risks will be mitigated by working with WPLP on coordinating the project schedule.

SS-03 Nanticoke TS: Connect HVDC Lake Erie Circuits

Start Date:	Q2 2020	**Priority:**	High
In-Service Date:	Q2 2022	**3 Year Test Period Gross Cost ($M):**	17.0
Trigger(s): Third Party Request			
Outcomes: Connect ITC's HVDC line to the Ontario transmission system.			

A. NEED AND OUTCOME

Investment Need

This investment is required to facilitate the request from Lake Erie Connector LLC ("ITC") to connect a 1000MW High Voltage Direct Current ("HVDC") line between Ontario and Pennsylvania; with a connection to Hydro One's transmission system at Nanticoke TS.

Hydro One is required to make connections when requested by customers. Not proceeding with this investment would be a violation of the Transmission System Code and Hydro One's Transmission License. This project is assigned a High Priority in order to meet this customer obligation.

Investment Description

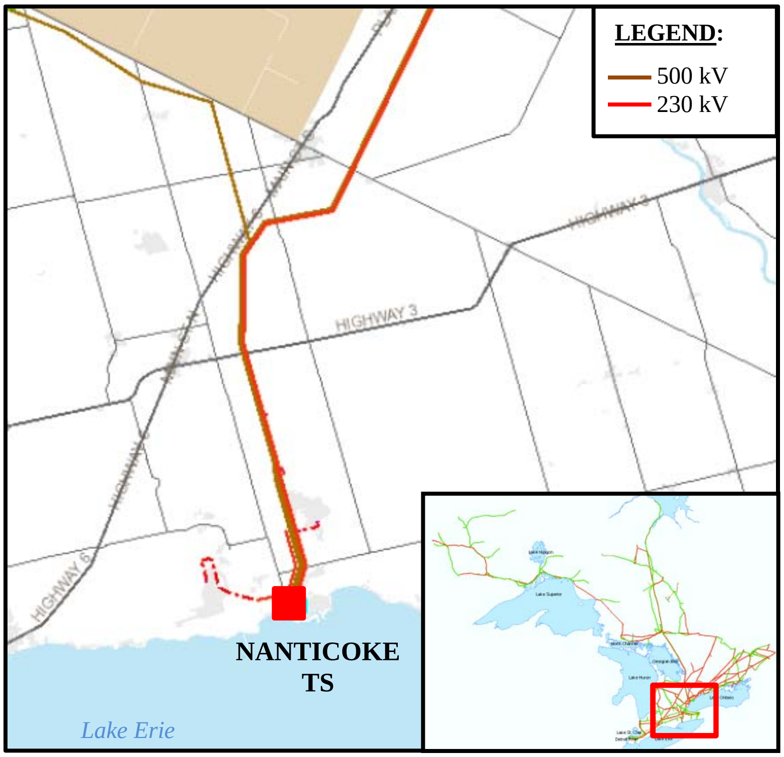
The ITC is constructing a 117 km long, underwater 1000MW HVDC cable line between converter stations in Nanticoke, Ontario and Erie, Pennsylvania, USA. Short AC lines will connect the converter stations to the Ontario and Pennsylvania transmission systems.

The proposed project involves connecting ITC's 500kV line at Nanticoke TS. This requires the expansion of the Nanticoke TS 500kV switchyard to accommodate the connection, including:

- Extension of the 500kV main busses;
- Addition of a new 500kV diameter with two new 500kV breakers;
- Protection and control modifications to incorporate the new line; and

- Relocation of one 500kV transmission tower.

A map showing the project location is provided below.



The System Impact Assessment and Customer Impact Assessment have been completed for this project. These assessments confirm that the incorporation of the project will not negatively impact the reliability of the IESO-controlled grid nor will it degrade the electricity service of the customers.

The ITC has obtained necessary approvals for a cross border interconnection project. The National Energy Board ("NEB") issued a Certificate of Public Convenience Necessity for the project on June 26, 2017. The US Department of Energy granted a Presidential Permit for the project on January 12, 2017.

Commencement of the project will be subject to the signing of the Capital Cost Recovery Agreement ("CCRA") with the customer.

Witness: Robert Reinmuller

Outcomes

This investment will provide the required connection of the ITC HVDC line to the Ontario transmission system**.**

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Satisfy ITC's request for connection.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License and Transmission System Code to connect neighboring transmitters and provide customers with non-discriminatory access.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, are fully recoverable through capital contributions from ITC. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the project is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 1: Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	0.5	3.0	10.0	4.0	0.0	0.0	0.0	17.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.5**	**3.0**	**10.0**	**4.0**	**0.0**	**0.0**	**0.0**	**17.5**
Less Capital Contributions	0.5	3.0	10.0	4.0	0.0	0.0	0.0	17.5
Net Investment Cost	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

No alternative was considered, as this investment is in response to a specific request from ITC.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as: the outage availability that is required for the work to be executed. These risks will be mitigated by setting a schedule that aligns with the outage availability. There is also a risk that the customer requirements may change resulting in a delay or cancellation of the need for this project. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer decides to cancel the project.

SS-04 East-West Tie Connection

Start Date:	Q2 2018	**Priority:**	High
In-Service Date:	Q2 2022	**3 Year Test Period Gross Cost ($M):**	107.7
Trigger(s): Third Party Request, Political Commitment			
Outcomes: Connect the new East-West Tie Line to the transmission system by expanding and reconfiguring Wawa TS, Marathon TS and Lakehead TS.			

A. NEED AND OUTCOME

Investment Need

The East-West Tie ("EWT"), identified as a priority project in the 2013 Long-Term Energy Plan ("LTEP") and reaffirmed in the 2017 LTEP, is a cornerstone of the government's policy to support expansion of transmission infrastructure in North-Western Ontario. The EWT project consists of building a new 450 km long 230kV double circuit transmission line between Wawa and Thunder Bay in Northern Ontario and is the IESO recommended alternative to maintain a reliable and cost-effective supply of electricity to North-Western Ontario for the long term.

Under the authority of Section 96.1 (1) of the *Ontario Energy Board Act*, the Lieutenant Governor in Council made an order declaring that the construction of the EWT transmission line is needed as a priority project.

In 2013, the Ontario Energy Board designated Upper Canada Transmission Inc., now operating as NextBridge Infrastructure ("NextBridge"), to carry out the development of the new EWT transmission line. On January 30, 2019 the Ontario Minister of Energy issued an Order in Council and Directive to the Ontario Energy Board, mandating that the new EWT transmission line will be constructed by NextBridge. Hydro One as the neighbouring transmitter is required to connect the new lines to the existing transmission system.

This investment, in addition to connecting the new transmission line, includes expansion and reconfiguration of the three stations, Wawa TS, Marathon TS and Lakehead TS as required by the IESO's System Impact Assessment. This investment has been assigned a High Priority in accordance with the EWT transmission line being designated as priority project.

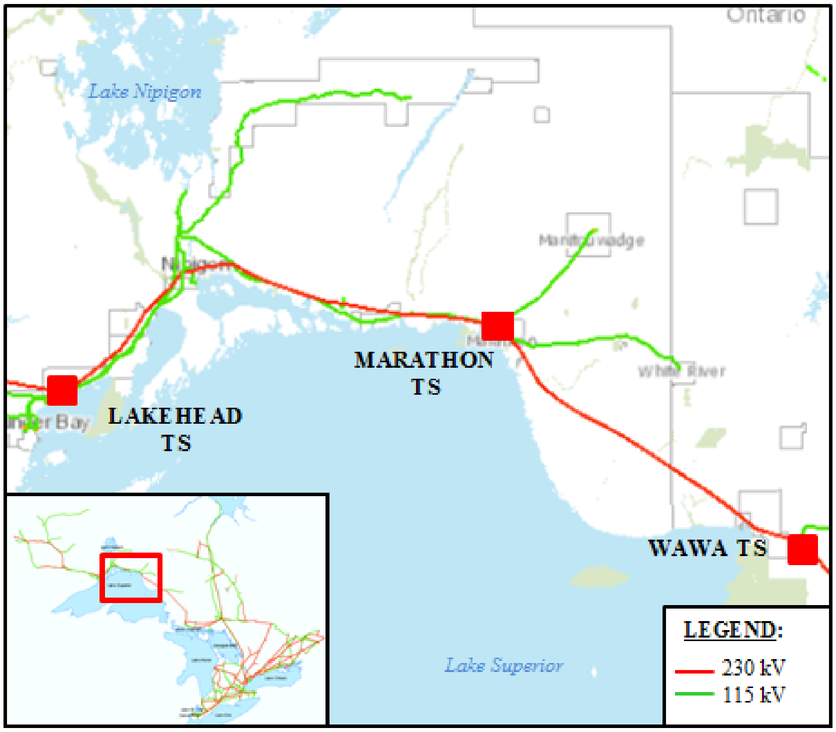
Investment Description

The proposed project constitutes Stage 1 of the EWT station work, and involves the reconfiguration and modification of the existing stations to incorporate the new 230kV EWT transmission line and provide 450MW East-West power transfer capability while respecting the reliability standards of North American Electric Reliability Corporation ("NERC") and the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). Stage 1 of the project requires the following:

- Installation of necessary switching facilities to connect the new East-West Tie 230kV circuits at Wawa TS, Marathon TS, and Lakehead TS, including 12 breakers and associated switches, protection and control, etc.;
- Re-termination of the existing 230kV circuits (W21M, W22M and W23K at Wawa TS; and W21M, M23L at Marathon TS), including 5 breakers, associated switches, protection and control, etc.;
- Addition of two new 230kV shunt reactors at Marathon TS and a 230kV shunt reactor and 230kV shunt capacitor bank at Lakehead TS, including 9 breakers, associated switches, protection and control, etc.; and
- Expansion of the existing Northwest Special Protection Scheme to reject load, switch reactors and capacitors, and cross-trip 115kV lines in response to 230kV contingencies.

Stage 2 of the project, which is not included in this investment, consists of the installation of a static-var compensator at Marathon TS and upgrade of the 115kV circuits (A5A and T1M) to increase the East-West transfer capability to 650MW, when the need arises.

A map showing the project location is provided below.



The System Impact Assessment and Customer Impact Assessment were completed in 2016 and 2017 respectively; both confirm that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers.

Hydro One applied for "Leave to Construct" approval for the Stage 1 of the EWT station work (EB-2017-0194), under Section 92 of the *Ontario Energy Board Act*. A summary of the need, project description, risk, and costs have been presented in the Section 92 application. In its Decision and Order, dated December 20, 2018, the Ontario Energy Board approved Hydro One's application for the station work, subject to granting "Leave to Construct" approval for the new transmission line between Wawa and Thunder Bay. The Board also granted Hydro One approval of the land purchase agreements and temporary land use or access agreements under Section 97 of the Act.

Outcomes

This investment will provide a reliable and cost-effective supply of electricity in North-Western Ontario, increase operational flexibility, reduce congestion payments and remove a barrier to resource development in the region.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Improve reliability while increasing the transfer capability.
Operational Effectiveness	• Provide operational flexibility by providing adequate reactive support to operate the system within voltage limits.
Public Policy Responsiveness	• Comply with the government policy and direction for providing sufficient capacity for demand growth in North-Western Ontario.

B. EXPENDITURE PLAN

This project is non-discretionary. The project costs, as presented in the table below, will be recovered from the network rate pool as these 230kV facilities are network assets and thus no capital contribution is required from customers.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	47.7	46.6	39.8	23.2	0.0	0.0	0.0	157.3
Less Removals	0.4	0.3	1.0	0.6	0.0	0.0	0.0	2.3
Gross Investment Cost	**47.3**	**46.3**	**38.8**	**22.6**	**0.0**	**0.0**	**0.0**	**155.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**47.3**	**46.3**	**38.8**	**22.6**	**0.0**	**0.0**	**0.0**	**155.0**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

Hydro One in consultation with the IESO, considered two alternatives to provide connection of the EWT transmission line to Hydro One's transmission system. Each of these alternatives consists of two stages, as recommended by the IESO, to address the 450MW near-term and 650MW future requirement for East-West transfer capability. In both alternatives the second stage will be completed when the need arises for 650MW transfer capability.

- Alternative 1: In Stage 1 the two new 230kV EWT circuits are connected together to form one super-circuit (or twinned circuit) and the two existing 230kV EWT circuits are connected together to create a second super-circuit. This was expected to reduce the station work in Stage 1 by allowing the use of existing line terminations. In Stage 2, the two twinned circuits are separated into four circuits and the stations reconfigured to individually terminate the four circuits at the stations. A static-var compensator is also added at Marathon TS.

- Alternative 2 (Recommended): In Stage 1, the three terminal stations are reconfigured to connect the two new 230kV EWT circuits individually at each of the stations. In Stage 2, a static-var compensator is added at Marathon TS.

Both Alternative 1 and 2 would meet the required transfer capability; however Alternative 2 has lower total cost compared to Alternative 1 and poses less risk with respect to technical challenges such as: outages; configurations; capabilities of existing breakers, protections; and connection of existing direct-connected customer. Therefore Alternative 2 is the recommended alternative.

D. EXECUTION RISK AND MITIGATION

The risks to the completion of this investment as planned would be as a result of potential delays in securing regulatory approvals and outage availability. These risks are mitigated by developing project construction schedule that aligns with the outage availability.

SS-05 St. Lawrence TS: Replace Phase Shifters PS33 and PS34

Start Date:	Q4 2018	**Priority:**	High
In-Service Date:	Q4 2022	**3 Year Test Period Gross Cost ($M):**	36.0
Trigger(s):	Operating Reliability, Equipment Failure		
Outcomes:	Maintain interconnection capability at the Ontario – New York intertie at St. Lawrence TS.		

A. NEED AND OUTCOME

Investment Need

This investment is required to replace the phase shifters (PS33, PSR34) at St. Lawrence TS. These phase shifters are part of the Ontario-New York 230kV interconnection circuits (L33P/L34P) at St. Lawrence TS. Phase shifters provide an important and preferred means of achieving active power flow control in a transmission system, including enforcing power flow and rebalancing line loading. In this case, phase shifters (PS33, PSR34) are used to control flow on the Ontario-New York interconnection lines, maximize east-west transfers in Ontario and help reduce overall losses.

The phase shifter (PS33) failed in April 2018 due to an arcing fault in its internal winding and is no longer serviceable. With the failure of this phase shifter, only phase shifter (PSR34) is left in-service and intertie transfer capability has been reduced from 400MW to 200MW, impacting both Ontario and New York. The remaining phase shifter (PSR34) has exceeded its expected service life of 40 years and is also planned to be replaced to avoid the risk of another unexpected phase shifter failure at the intertie.

Following the phase shifter (PS33) failure event, the New York Independent System Operator (“NYISO”), the New York Power Authority (“NYPA”), the Ontario Independent Electricity System Operator (“IESO”) and Hydro One discussed the future of the Ontario-New York 230kV interconnection at St. Lawrence TS. All parties agreed that the existing interconnection is still needed and that both phase shifters are required to maintain interconnection capability.

Not proceeding with this investment would result in a reduction of the interconnection capacity and the reliability of the Ontario – New York intertie at St. Lawrence TS.

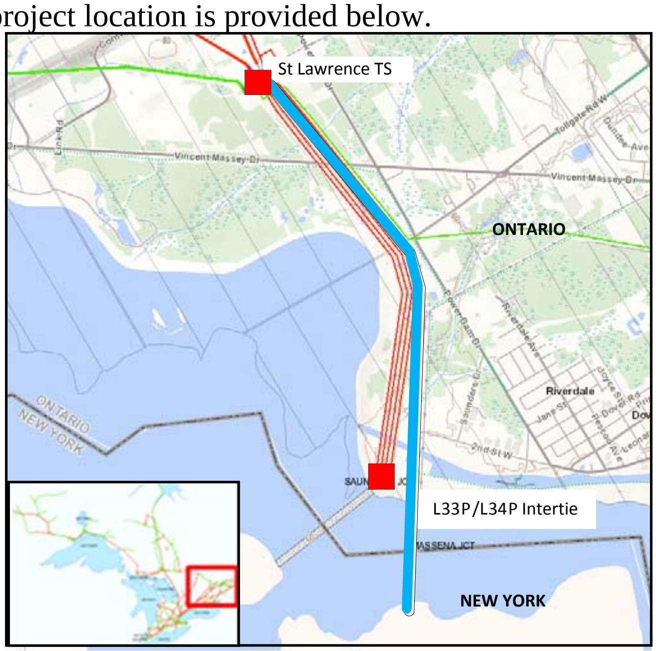
Investment Description

In response to the unavailability of phase shifter (PS33) and to maintain interconnection capability on the Ontario-New York intertie at St. Lawrence TS, Hydro One plans to:

- Replace phase shifter (PS33) and its associated voltage regulator transformer (R33). The new unit will be rated similar to the existing unit but will combine the phase shifter and voltage regulator transformer functions into one unit; and
- Replace the existing phase shifter (PSR34), which is a combined phase shifter and regulating transformer; as well as two 230kV breakers and disconnect switches. The new unit will be rated similar to the existing unit.

To ensure that the capability of the Ontario – New York interconnection is restored as soon as possible Hydro One has placed a High Priority on this investment. The replacement of phase shifter (PS33) is to be completed by 2021 and phase shifter (PSR34) by 2022.

A map showing the project location is provided below.



Outcomes

This investment will maintain interconnection capability between Ontario and New York.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Restore reliability of the bulk transmission system.
Operational Effectiveness	• Eliminate operating constraints resulting from operating with one phase shifter only.
Public Policy Responsiveness	• Maintain interconnection capability between Ontario and New York.

B. EXPENDITURE PLAN

The project costs, as presented in the table below, will be shared equally between Hydro One and NYPA. Hydro One's share of the project costs will be recovered from the network rate pool as these phase shifters are network assets.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	0.5	9.0	18.0	9.0	0.0	0.0	0.0	36.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.5**	**9.0**	**18.0**	**9.0**	**0.0**	**0.0**	**0.0**	**36.5**
Less Capital Contributions	0.0	4.5	9.0	4.5	0.0	0.0	0.0	18.0
Net Investment Cost	**0.5**	**4.5**	**9.0**	**4.5**	**0.0**	**0.0**	**0.0**	**18.5**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

There is no cost effective alternative to replacing the phase shifters (PS33 and PSR34) at St. Lawrence TS for restoring the interconnection capacity between Ontario and New York. Replacement of the two phase shifters is the preferred and recommended option.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as: the procurement of the specialized and complex phase shifter equipment and outage availability that is required for the work to be executed. These risks will be mitigated by setting a schedule that aligns with equipment and outage availability.

SS-06 Merivale TS to Hawthorne TS: 230kV Conductor Upgrade

Start Date:	Q2 2020	**Priority:**	High
In-Service Date:	Q4 2022	**3 Year Test Period Gross Cost ($M):**	23.4
Trigger(s): Third Party Request, Political Commitment			
Outcomes: Increase transfer capacity.			

A. NEED AND OUTCOME

Investment Need

This investment is required to increase the loading capability of the 230kV double circuit line (M30A/M31A) between Hawthorne TS and Merivale TS to serve growth in western Ottawa and optimize the use of Ontario's interties with Quebec; as identified in the 2017 Long-Term Energy Plan ("LTEP").

The IESO's 2017 Ontario-Quebec Interconnection Capability technical review has indicated that the two 230kV circuits between Hawthorne TS and Merivale TS are currently a limiting factor in Ontario's capability to import electricity from Quebec. These circuits must be upgraded to allow increased import capability in order to optimize the connection with the Quebec transmission system. The 2017 LTEP has also identified a need to proceed with this project in order to serve anticipated growth in western Ottawa.

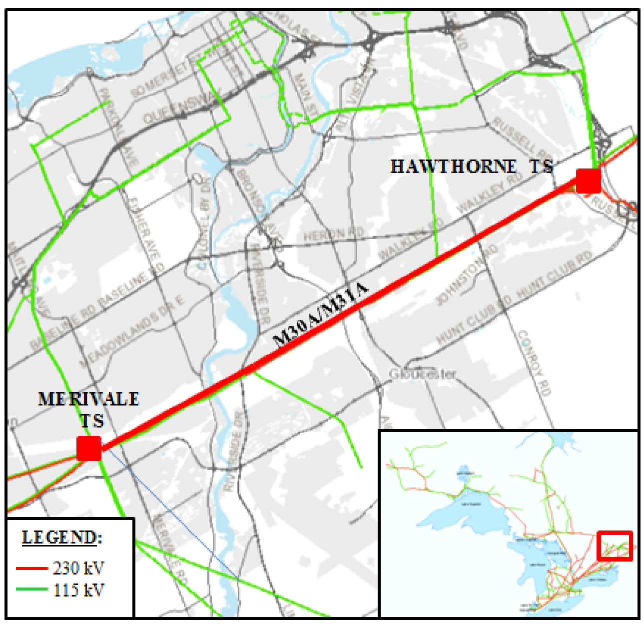
Not proceeding with this investment would result in not complying with provincial policy direction as laid out in the 2017 LTEP. This project is assigned a High Priority in order to meet this obligation.

Investment Description

Hawthorne TS and Merivale TS are the two main supply stations for the Ottawa area. The flow on the 230kV circuits (M30A and M31A) connecting Hawthorne TS to Merivale TS is largely dependent on the loads in western Ottawa and on the imports from Hydro Quebec into Hawthorne TS.

The IESO has identified that the conductors comprising the two 230kV circuits between Hawthorne TS and Merivale TS would require upgrading to accommodate the full capacity of the 1250MW Ontario-Quebec Intertie. This proposed project involves replacing the existing conductor with a two conductor bundle thereby allowing the circuit rating to be increased from 650MW to about 1080MW.

A map showing the project location is provided below.



The System Impact Assessment has been completed for this project which confirms that the incorporation of these facilities will not adversely impact the reliability of the IESO-controlled grid. The Customer Impact Assessment will be completed in Q2 2019; however, based on the System Impact Assessment results, the project is not expected to affect electricity service to transmission customers in the Ottawa area.

Hydro One will apply for “Leave to Construct” approval under Section 92 of the *Ontario Energy Board Act* once direction from IESO to proceed is provided. A summary of the need, project description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application. There are no land matters as the existing right of way will be utilized.

Outcomes

This investment will increase loading capability of the 230kV circuits between Hawthorne TS and Merivale TS to satisfy the requirements of forecasted loads in western Ottawa and optimize the electricity imports from Quebec.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Ensure adequate supply capacity for western Ottawa loads.
Operational Effectiveness	• Increase operating flexibility of the transmission system by providing increase in transfer capacity.
Public Policy Responsiveness	• Comply with IESO request to increase transfer capability. • Align with the direction in the 2017 Long-Term Energy Plan.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recovered from the network rate pool as these 230kV circuits are network assets and thus no capital contribution is required from customers.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	0.7	5.0	10.0	8.4	0.0	0.0	0.0	24.1
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.7**	**5.0**	**10.0**	**8.4**	**0.0**	**0.0**	**0.0**	**24.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.7**	**5.0**	**10.0**	**8.4**	**0.0**	**0.0**	**0.0**	**24.1**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

Two alternatives were considered for providing the additional loading capability.

- Alternative 1: Build a new 12 km 230kV double-circuit transmission line between Hawthorne TS and Merivale TS. The right of way for the existing 230kV transmission line does not have sufficient space for additional circuits; requiring acquisition of a new right of way.

- Alternative 2 (Recommended): Re-conductor the existing 12 km 230kV double-circuit transmission line (M30A/M31A) with higher capacity conductor. The existing tower structures are adequate to support the new conductor and would not require replacement.

Both Alternative 1 and 2 would address the need; however Alternative 1 was not considered further due to the higher costs, community impact, and complexity of securing a new right of way. Alternative 2 is the recommended alternative.

D. EXECUTION RISK AND MITIGATION

The risks with respect to the execution of this investment as planned would be as a result of potential delays in securing the Section 92 approval. These risks will be mitigated by initiating the Section 92 application process in a timely manner after receiving the IESO direction to proceed with the project.

Normal project risks may also affect the timely completion of the project such as the outage availability that is required for the work to be executed. As the affected circuits are critical for supplying Ottawa, it may be challenging to schedule outages to complete the required work. These risks will be mitigated by setting a schedule that aligns with outage availability.

SS-07 Milton SS: Station Expansion and Connect 230kV Circuits

Start Date:	Q4 2022	**Priority:**	Medium
In-Service Date:	Q2 2025	**3 Year Test Period Gross Cost ($M):**	5.0
Trigger(s): System Adequacy			
Outcome: Provide adequate supply to West GTA region and improve system reliability.			

A. NEED AND OUTCOME

Investment Need

The IESO bulk system studies described in the 2015 North-West GTA Integrated Regional Resource Plan[1] had indicated that the bulk transmission facilities in West GTA; specifically the 500/230kV autotransformers at Trafalgar TS and the Trafalgar to Richview 230kV transmission circuits (R14T, R17T, R19T and R21T) would require relief as early as 2020. The two primary factors driving the need for relief were: (a) load growth in the GTA, specifically in the West GTA; and (b) increased inter-area flows due to the scheduled refurbishment of nuclear units at Bruce NGS and Darlington NGS along with the planned retirement of Pickering NGS.

The North-West GTA Integrated Regional Resource Plan had also identified that loads connected to the Burlington TS to Trafalgar 230kV circuits (T38B/T39B) are at risk of not meeting the restoration criteria as defined in the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC").

In order to address these needs, the IESO had recommended adding 500/230kV transformation facilities at Milton SS and reconfiguring the 230kV transmission facilities in North-West GTA.

[1] *http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Northwest-Greater-Toronto/2015-Northwest-GTA-IRRP-Report.pdf*

As described in the 2017 Long-Term Energy Plan; growth in demand, the eventual retirement of the Pickering NGS and new renewable generation all impact the bulk transmission system in West GTA. The IESO is studying the need and timing of these transmission reinforcements. Based on the lower load growth forecast and the deferral of the Pickering NGS retirement to 2024, the need for the Milton SS expansion and reconfiguration of 230kV transmission facilities have been deferred to 2025.

Not proceeding with this investment would limit transfer capability and would result in inadequate capacity to supply the West GTA loads.

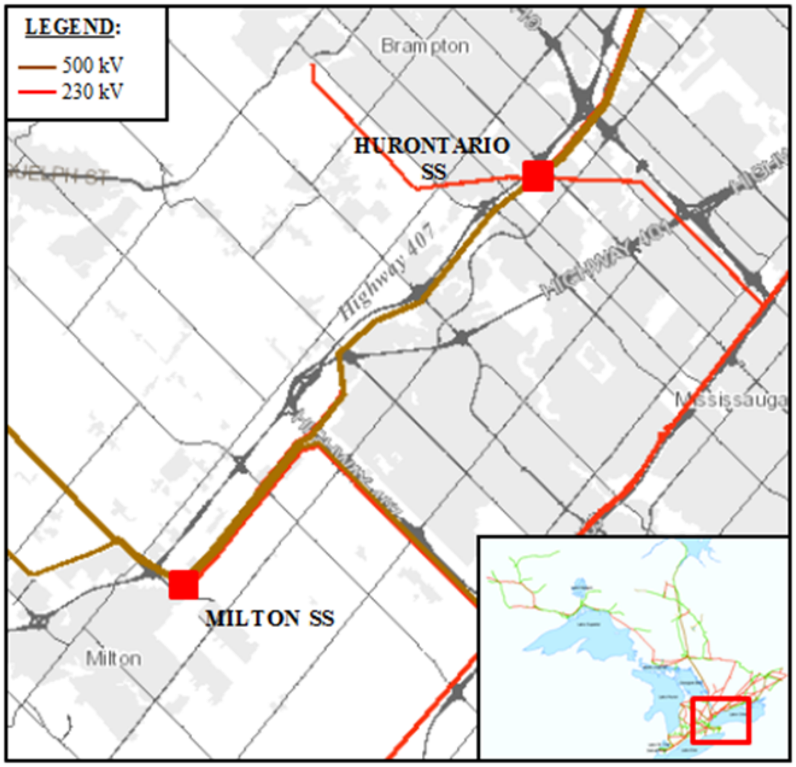
Investment Description

The proposed project involves the:

- Installation of two 500/230kV, 750MVA autotransformers and associated switching facilities at Milton SS;
- Construction of a new 230kV switchyard at Milton SS;
- Construction of an approximately 12.5 km 230kV double circuit line to connect the new Milton SS to Hurontario SS using the existing right of way; and
- Modification of Hurontario SS to incorporate the new 230kV circuits.

The new facilities will provide relief for the loading on autotransformers at Trafalgar TS and the 230kV circuits between Richview TS and Trafalgar TS. The reconfiguration will also allow the 230kV circuits (T38B/T39B) loading to continue to comply with the IESO's ORTAC as loads increase.

A map showing the project location is provided below.



Once the IESO confirms the need and timing for the project Hydro One will apply for a "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act*, and a Class Environmental Assessment approval under the *Environmental Assessment Act*. A summary of the need, project description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application. All land matters will be addressed in the Section 92 application.

The project is not expected to adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment will be completed to confirm the above prior to the submission of the Section 92 application.

Outcomes

This investment will provide adequate supply to West GTA region and improve system reliability.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Ensure adequate capacity to supply the West GTA loads.
Operational Effectiveness	• Improve operational flexibility with the addition of 230kV transformation at Milton SS.
Public Policy Responsiveness	• Align with the direction in the 2017 Long-Term Energy Plan.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recovered from the network rate pool as these 500kV and 230kV facilities are network assets and thus no capital contribution is required from customers.

Table 1: Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	0.0	0.0	2.0	3.0	69.4	119.1	45.0	238.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**0.0**	**2.0**	**3.0**	**69.4**	**119.1**	**45.0**	**238.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**0.0**	**2.0**	**3.0**	**69.4**	**119.1**	**45.0**	**238.5**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

Two transmission alternatives were considered by the IESO to address the needs in the West GTA region. These alternatives are:

- Alternative 1 (Recommended): Install two new autotransformers, construct a new 230kV switchyard at Milton SS, and construct approximately 12.5 km of double circuit 230kV line between Milton SS and Hurontario SS.

- Alternative 2: Install two new autotransformers, expand the 230kV switchyard at Trafalgar TS, and construct approximately 8 km of double circuit 230kV line between Meadowvale TS and Hurontario SS.

The IESO concluded based on preliminary studies that Alternative 1 is the preferred option as it is the least cost alternative and provides greater operating flexibility.

E. EXECUTION RISK AND MITIGATION

The risks with respect to execution of this investment as planned would be as a result of potential delays in securing the Section 92 and environmental assessment approvals. These risks will be mitigated by initiating the Section 92 application process and environmental assessment process in a timely manner.

SS-08 Northwest Bulk Transmission Line

Start Date:	Q1 2019	**Priority:**	High
In-Service Date:	Q4 2022*	**3 Year Test Period Gross Cost ($M):**	29.8
Trigger(s): Third Party Request, Political Commitment			
Outcomes: Undertake the development work required for submission of approval requests for the building of a 230kV double circuit line between Thunder Bay and Atikokan and a single-circuit line between Atikokan and Dryden.			

** As described below, this date represents the completion of the required development work to the point of approval submission only.*

A. NEED AND OUTCOME

Investment Need

This investment is required in response to the IESO's request to Hydro One dated October 24, 2018 (see Appendix "A" below) to undertake development work for the Northwest Bulk Transmission Line ("NWBTL") Project, which is a priority project identified in the 2013 and 2017 Long-Term Energy Plans ("LTEP"). The purpose of this project is to augment the transmission capacity and maintain the reliability of electricity supply to the area of northwestern Ontario located west of Thunder Bay and support forecast electricity demand growth.

The 2017 LTEP recommended that the project proceed in three phases:

- <u>Phase One</u>: a line from Thunder Bay to Atikokan by 2024.
- <u>Phase Two</u>: a line from Atikokan to Dryden by 2034 (or earlier depending on the demand forecast).
- <u>Phase Three</u>: a line from Dryden to the Manitoba border, if needed, after 2035 (or earlier if recommended by the IESO).

An Order in Council issued December 11, 2013 directed the Ontario Energy Board to amend Hydro One's Transmission Licence, requiring Hydro One to develop and seek approvals for the NWBTL in accordance with the scope and timing recommended by the IESO.

The IESO has recently reviewed the NWBTL in relation to updated area load forecast, and outlined the recommended scope and timing of the project in its October 24, 2018 letter to Hydro One. In that letter, the IESO indicated that while additional transmission capacity in the area may not be needed until the mid-2030s, a capacity need could potentially arise under the high load growth scenario in the early 2020s. The IESO will continue to monitor the development and load growth in the area and advise when the new line would be required.

Given the risks associated with load forecast uncertainty, and to shorten the project lead time if the need for additional capacity arises pursuant to the high growth scenario, the IESO recommends that Hydro One commence project development work as soon as possible on Phase One and Phase Two of the NWBTL as follows:

- Phase One: a new double circuit 230kV line from Lakehead TS to Mackenzie TS.
- Phase Two: a new single circuit 230kV line from Mackenzie TS to Dryden TS.

In addition, the IESO has also asked Hydro One to separate the necessary sections of the existing 230kV circuits (F25A, D26A) that originate from Mackenzie TS to ensure that the circuits do not share a common structure over a distance exceeding one mile.

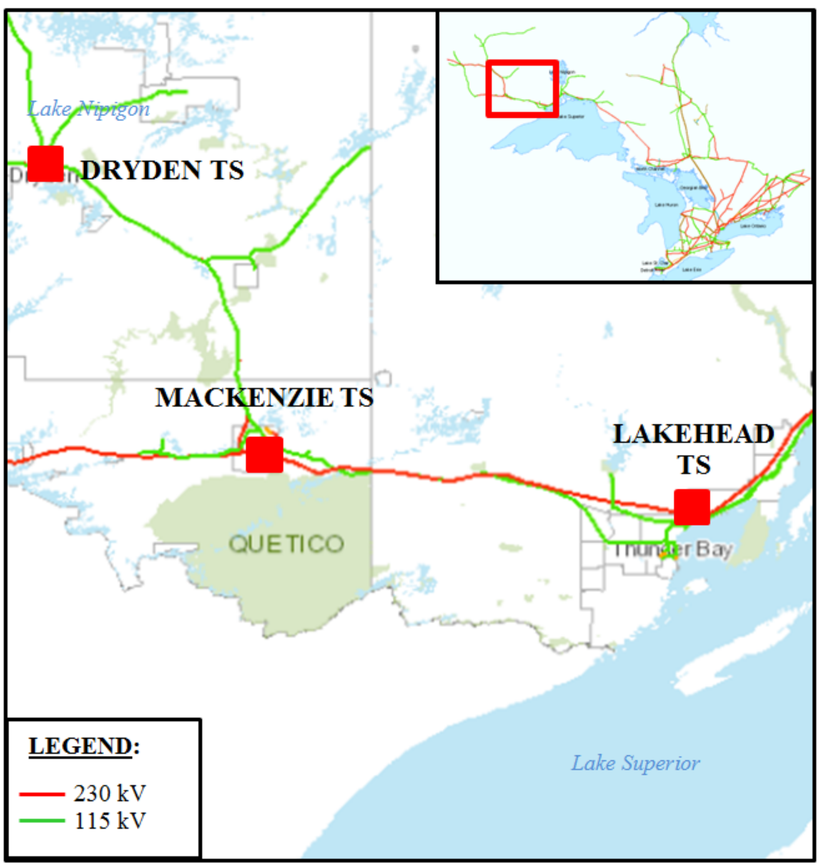
Not proceeding with this investment risks potential delay in providing additional transmission capacity when required. This project has been assigned a High Priority given the identification of the NWBTL as a priority project in the 2017 LTEP, and the most recent IESO determination that Hydro One should begin development work as soon as possible.

Investment Description

This investment will allow Hydro One to undertake the development work for Phase One and Phase Two of the NWBTL as described above. The scope of this development work includes:

- Initiating preliminary design/engineering;
- Preparing cost estimates;
- Carrying out public engagement/consultation;
- Undertaking routing and siting studies; and
- Environmental assessment.

A map showing the general location of the proposed NWBTL project is provided below.



Outcomes

Pursuant to the IESO's request, this investment will allow Hydro One to undertake the development work for the installation of Phase One and Phase Two of the NWBTL, which will increase transfer capability in the area west of Thunder Bay and provide sufficient capacity for the forecasted growing demand.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Ensure timely capacity increase to meet future customer loads.
Operational Effectiveness	• Maintain reliability while increasing the transfer capability in the area.
Public Policy Responsiveness	• Comply with the IESO request to initiate the development work for Phase 1 and Phase 2 of the NWBTL to provide sufficient capacity for demand growth in Northwest Ontario, including connection of remote communities. • Align with the direction in the 2017 Long-Term Energy Plan.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, are only for development work, including preliminary design/engineering, cost estimation, public engagement/consultation, routing and siting, and environmental assessment, for Phase One and Phase Two of the NWBTL. Some of the expenditure may extend beyond 2022, to facilitate interactions with regulators during Environmental Assessment review periods and ongoing consultation with Indigenous Communities and stakeholders. These project costs will be recovered from the network rate pool as these 230kV facilities are network assets and thus no capital contribution is required from customers.

Table 1: Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total[2]
Capital[1] and Minor Fixed Assets	5.2	8.0	12.9	8.9	0.0	0.0	0.0	35.0
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**5.2**	**8.0**	**12.9**	**8.9**	**0.0**	**0.0**	**0.0**	**35.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**5.2**	**8.0**	**12.9**	**8.9**	**0.0**	**0.0**	**0.0**	**35.0**

[1] Includes Overhead at current rates.
[2] As described above, this would bring development work to the point required for submission of approval requests only.

C. ALTERNATIVES

No alternative was considered by Hydro One, as this investment is in response to a specific directive.

D. EXECUTION RISK AND MITIGATION

This investment covers only the development work, including environmental assessment, for the NWBTL. Normal project risks associated with extensive public consultation apply, as well as potential delays for obtaining the final environmental assessment approvals.

APPENDIX "A" – Letter from the IESO to Hydro One

ieso
Connecting Today.
Powering Tomorrow.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

October 24, 2018

Mr. Robert Reinmuller
Director, Transmission Planning
Hydro One Inc.
483 Bay Street, 13th Floor, North Tower
Toronto, Ontario M5G 2P5

Dear Robert,

Update on the Need and Scope for the Northwest Bulk Transmission Line

The Independent Electricity System Operator (the "IESO") recently updated its electrical load forecast and completed an assessment of the need for additional capacity to supply the West of Thunder Bay and North of Dryden areas (together, the "Region"), shown in Figure 1. The purpose of this letter is to describe the supply needs for the Region and the IESO's recommended next steps for meeting those needs.

Figure 1 – The Region

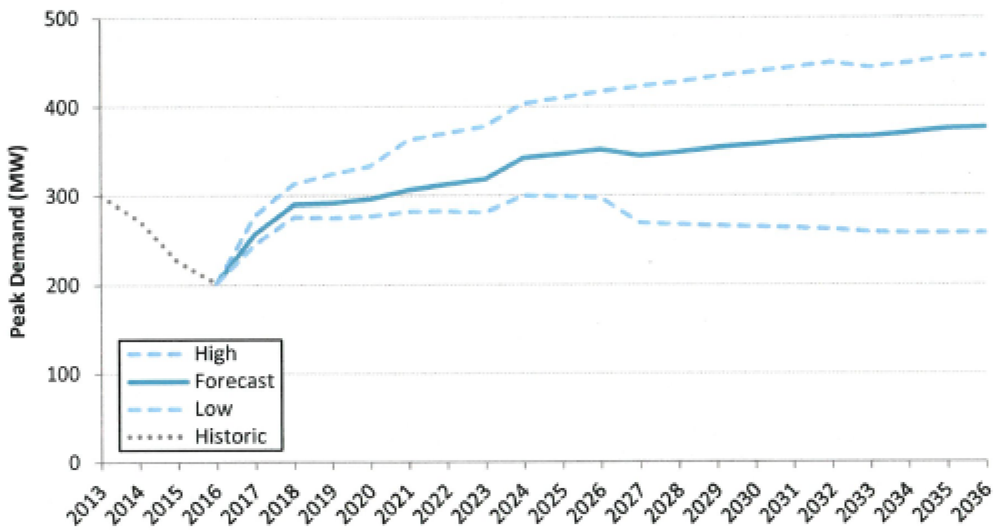
Supply Needs in the Region

Figure 2 below shows an updated electrical load forecast for the Region. The updated forecast considers new loads from potential mining developments, the connection of remote communities and the removal of loads from the cancelled Energy East pipeline conversion project.

Based on the forecast the Region is adequately supplied today; however, a need for additional capacity will arise in the mid-2030s.

The IESO's updated electrical load forecast also includes high and low growth scenarios to capture the uncertainty around industrial developments. Under the high growth scenario, which considers development of the Ring of Fire with electricity supplied by the Ontario transmission system, a capacity need could potentially arise in the early 2020s.

Figure 2 - Electrical Load Forecast – the Region



Addressing the Need

The Northwest Bulk Transmission Line Project (the "Project") was identified as a priority project in the 2017 Long-Term Energy Plan (the "LTEP") and can address the capacity needs described above. The LTEP divides the Project into three phases:

Phase 1 – a line from Thunder Bay to Atikokan;

Phase 2 – a line from Atikokan to Dryden; and

Phase 3 – a line from Dryden to the Manitoba border.

An Order in Council issued December 11, 2013 directed the Ontario Energy Board to amend the Hydro One Networks Inc. Electricity Transmission License to require Hydro One to develop and seek approvals for the Project in accordance with the scope and timing recommended by the IESO. The IESO's recommended scope and timing is outlined in the following paragraphs.

Scope and Timing

Since the capacity need is not likely to materialize until the mid-2030s, a commitment for additional supply to the Region is not required at this time. However, the IESO recognizes the risks associated with load forecast uncertainty and the potential for large industrial projects to add significant load to the Region utilizing the remaining capacity margin sooner than anticipated.

Therefore, to shorten the Project lead time if the need for additional capacity materializes earlier than expected, the IESO recommends that Hydro One begin development work on Phase 1 and Phase 2 of the Project as soon as possible. The scope of development work is to include preliminary design/engineering, cost estimation, public engagement/consultation, routing and siting, and Environmental Assessment. At this time the IESO is not committing to a timeline for the construction of the line. The IESO will continue to monitor developments in the Region to determine when construction of the transmission line should begin.

To supply the Region under the high growth scenario, the Project must meet the following specifications:

a) Consist of a new double circuit 230 kV line between Lakehead TS and Mackenzie TS (Phase 1) with a thermal capacity that is equal to or greater than the existing double-circuit 230 kV transmission between Lakehead TS and Mackenzie TS. This would achieve the required westbound transfer of at least 350 MW into Mackenzie TS and Moose Lake TS.

b) Consist of a new single circuit 230 kV line from Mackenzie TS to Dryden TS (Phase 2) with a thermal capacity that is equal to or greater than the existing single-circuit 230 kV transmission line between Mackenzie TS and Dryden TS. This would achieve the required westbound transfer of at least 350 MW from MacKenzie and Moose Lake.

c) Separate the necessary sections of F25A and D26A to ensure the circuits do not share a common structure over a distance that exceeds one mile.

Hydro One should consider various routing options as appropriate. Since requirements for switching and reactive facilities would depend on the configuration and line options, they are not specified at this time.

The 2014 letter from the Ontario Power Authority (the "OPA") to Hydro One indicated that the Project must be capable of 550 MW transfer west from the Thunder Bay area. At the time the letter was written, the OPA's electrical load forecast was significantly higher and included potential mining developments and the Energy East pipeline conversion project. If in the future additional transfer capability beyond 350 MW is needed, the solution would be to install dynamic reactive facilities in addition to the transmission lines indicated above.

The IESO will provide support to Hydro One as required, including discussion of possible routing alternatives. As well, the IESO will continue to monitor developments in the Region and confirm the best course of action to address supply needs, and will keep Hydro One apprised of this work.

Sincerely,

Ahmed Maria
Director - Transmission Planning
Independent Electricity System Operator

cc: Ms. Darlene Bradley, Hydro One
Mr. Leonard Kula, IESO
Mr. Terry Young, IESO
Mr. Alex Merrick, IESO

SS-09 Barrie Area Transmission Upgrade

Start Date:	Q2 2019	**Priority:**	High
In-Service Date:	Q2 2022	**3 Year Test Period Gross Cost ($M):**	74.8
Trigger(s): Supply Reliability, End-of-Life			
Outcomes: Increase supply reliability and ensure adequate capacity for the Barrie area.			

A. NEED AND OUTCOME

Investment Need

This investment is required to address the capacity needs in the Barrie/Innisfil sub-region and the poor condition of the aging assets at Barrie TS and Essa TS; as documented in the South Georgian Bay/Muskoka Region Infrastructure Plan (Exhibit B, Tab 1, Schedule 1, TSP Section 1.2, Attachment 13).

Barrie TS is located in the Barrie/Innisfil sub-region and is the main supply for the City of Barrie. Barrie TS is a 115/44kV transformer station with a capacity of 115MVA and is supplied from 115kV circuits (E3B/E4B) from Essa TS. Barrie TS and the 115kV circuits (E3B/E4B) are supplied from the 230/115kV autotransformers and the 115kV switchyard at Essa TS. Both Barrie TS and Essa TS facilities are nearing end-of-life.

The Barrie area is experiencing significant load growth and the loading on Barrie TS currently exceeds its normal supply capacity. The 115kV circuits (E3B/E4B) are forecast to exceed the circuit capability by 2022.

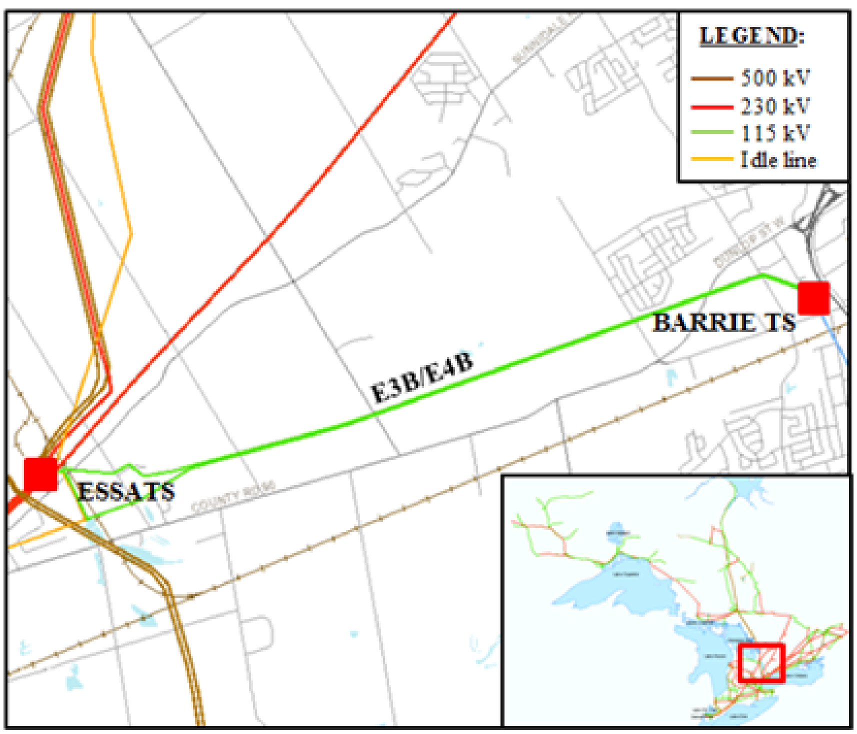
Not proceeding with this investment would result in the inability to supply forecast customer load demand, and an increased risk of load interruptions affecting supply reliability to customers. This project has been assigned a High Priority in order to provide capacity and maintain supply reliability to area customers.

Investment Description

The proposed project involves rebuilding Barrie TS as a 230kV supplied transformer station to address both the capacity and aging infrastructure related needs. The project requires the following:

- Replacement of the existing 115/44kV transformers with new 230/44kV transformers with a capacity of 170MVA;
- Construction of a new 44kV low voltage switchyard with eight 44kV feeders;
- Replacement of the existing 115kV Essa TS to Barrie TS single circuit lines (E3B/E4B) with a new 230kV double circuit line;
- Decommissioning and removal of the 230/115kV autotransformers and the 115kV switchyard at Essa TS; and
- Construction of a new 230kV diameter to provide two new switching positions for the new 230kV circuits that will supply Barrie TS.

A map showing the project location is provided below.



The System Impact Assessment and Customer Impact Assessment have been completed for this project. These assessments confirm that the incorporation of these facilities will not negatively impact the reliability of the IESO-controlled grid nor will it degrade the electricity service of the customers.

Hydro One has also completed the Class Environmental Assessment for this project in March 2018 as required under the *Environmental Assessment Act*.

Hydro One will apply for a "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act* in Q2 2019. A summary of the need, project description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application. All land matters will be addressed in the Section 92 application.

Outcomes

This investment will address the end-of-life assets and provide capacity to meet current and forecast needs for the Barrie/Innisfil area.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Ensure adequate capacity to meet future load growth.
Operational Effectiveness	• Reduce line losses by increasing voltage from 115kV to 230kV.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recoverable from the network and connection rate pools for the respective new 230kV and 44kV facilities. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the project is placed in-service subject to the terms of the Connection Cost Recovery Agreement ("CCRA"). The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 1 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	8.4	38.1	28.2	8.5	0.0	0.0	0.0	83.2
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**8.4**	**38.1**	**28.2**	**8.5**	**0.0**	**0.0**	**0.0**	**83.2**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**8.4**	**38.1**	**28.2**	**8.5**	**0.0**	**0.0**	**0.0**	**83.2**

[1] *Includes Overhead at current rates.*

C. ALTERNATIVES

Two alternatives were considered to address the transformation capacity and end-of-life needs Barrie/Innisfil sub-region.

- Alternative 1: Continue to supply Barrie TS at 115kV. This would require like-for-like replacement of the existing equipment at Essa TS and Barrie TS to address the aging facilities, rebuilding the existing 115kV circuits (E3B/E4B) and constructing a second 115/44kV transformer station in order to meet the capacity needs.

- Alternative 2 (Recommended): Convert Barrie TS to 230kV supply. This would require replacing the existing 115kV facilities at Barrie TS and the existing 115kV circuits (E3B/E4B) with new 230kV facilities. The Essa TS 230/115kV facilities will be removed and a new 230kV diameter added to supply the two new 230kV circuits.

Alternative 1 (like-for-like option) provides for a limited capacity increase that cannot meet the future forecast requirements. Alternative 2 ensures adequate capacity to meet future load growth and has the least cost; therefore it is the recommended alternative.

D. EXECUTION RISK AND MITIGATION

The risks with respect to execution of this investment as planned would be as a result of potential delays in securing the Section 92 approval. These risks will be mitigated by initiating the Section 92 application process in a timely manner. There is also a risk that the area customer requirements may change resulting in a delay or cancellation of the need for this project. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer decides to cancel the project.

SS-10 Kapuskasing Area Transmission Reinforcement

Start Date:	Q1 2019	**Priority:**	High
In-Service Date:	Q4 2020	**3 Year Test Period Gross Cost ($M):**	10.4
Trigger(s): Third Party Request			
Outcome: Increase thermal rating and provide reactive control at Kapuskasing TS.			

A. NEED AND OUTCOME

Investment Need

This investment is to facilitate the IESO's request to Hydro One dated April 13, 2016 (see Appendix "A" below) to increase power transfer capability on the 115kV single circuit transmission line (H9K) and to provide reactive support to supply the Kapuskasing area loads following the contract expiry of Kapuskasing CGS and Calstock CGS.

The IESO bulk system study has identified that with the Kapuskasing CGS and Calstock CGS unavailable, there is a need to reinforce a section of the 115kV circuit (H9K) and to provide additional reactive support facilities at Kapuskasing TS to support the area loads.

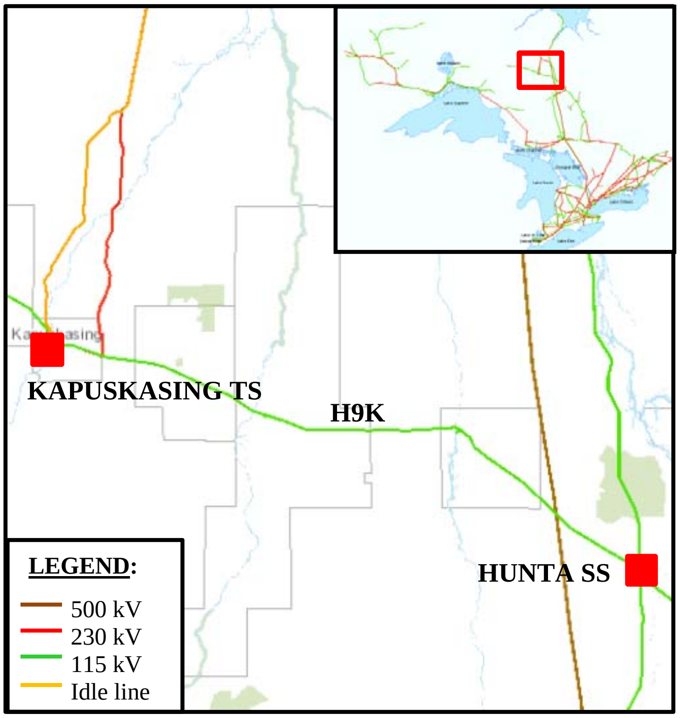
Not proceeding with investment would result in inadequate transfer capability and reactive support in the Kapuskasing area. This project is assigned a High Priority in order to maintain reliability and adequate voltage support in the area.

Investment Description

The proposed project, to reinforce supply to the Kapuskasing area, involves:

- Increasing the thermal rating of a section of the 115kV circuit (H9K) from Carmichael Falls Junction to Spruce Falls to 370A; and
- Installation of an 115kV, 10MVAR capacitor bank and 115kV, 10MVAR reactor at Kapuskasing TS to provide the reactive power control.

A map showing the project location is provided below.



The System Impact Assessment and Customer Impact Assessment have been completed for this project. These assessments confirm that the incorporation of these facilities will not negatively impact the reliability of the IESO-controlled grid nor will it degrade the electricity service of the customers.

Hydro One completed the Class Environmental Assessment for the project in November 2017 as required under the *Environmental Assessment Act*. Hydro One has also received "Leave to Construct" approval for the project from the Board on August 23, 2018 under Section 92 of the *Ontario Energy Board Act*. A summary of the need, project description, risk, and costs have been presented in the Section 92 application (EB-2018-0098). All land matters have been addressed in the Section 92 application.

Outcomes

This investment will maintain the reliability of supply, increase power transfer capability, and provide reactive support needed for the Kapuskasing area.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Ensure adequate supply to Kapuskasing area loads by increasing power transfer limits.
Operational Effectiveness	• Maintain reliability of supply to the Kapuskasing area.
Public Policy Responsiveness	• Comply with IESO request to increase transfer capability.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recovered from the network rate pool as these facilities are required to support the network, and thus no capital contribution is required from customers.

Table 1: Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	20.6	6.7	3.8	0.0	0.0	0.0	0.0	31.0
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**20.6**	**6.7**	**3.8**	**0.0**	**0.0**	**0.0**	**0.0**	**31.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**20.6**	**6.7**	**3.8**	**0.0**	**0.0**	**0.0**	**0.0**	**31.0**

[1] Includes Overhead at current rates.

C. ALTERNATIVES

No alternative was considered, as this investment is in response to a specific request from the IESO.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as: the outage availability that is required for the work to be executed. These risks will be mitigated by setting a schedule that aligns with the outage availability.

1 **APPENDIX "A" – Letter from IESO to Hydro One**

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Powering Tomorrow.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

April 13, 2016

Mr. Bing Young
Director, System Development
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario M5G 2C9

Dear: Bing

Re: Bulk System Reinforcement for the Kapuskasing Area

Background

On September 1, 2015, the IESO published the NUG ("Non-Utility Generator") Framework Assessment report ("NUG Report") to the Minister of Energy. This report identified that following the contract expiry of Kapuskasing Customer Generating Station ("CGS") and Calstock CGS, local reliability standards may not be met without further reinforcement. The NUG Report also indicated that the North/East of Sudbury regional planning study would begin immediately.

Since September 2015, the IESO has been working jointly with Hydro One to assess the local issues identified in the NUG Report. This included initiating the North/East of Sudbury Regional Planning process on September 24, 2015. Based on the fact that there were existing challenges in operating the bulk transmission system in the area, the IESO and Hydro One agreed that a bulk system study should be run in parallel with the formalized Regional Planning Process. This enabled the bulk system study to be expedited to ensure timely solutions are in place given the potential lead time for transmission based solutions.

The scope of the bulk system study for the Kapuskasing area investigated the adequacy and operability of the system supplying the area, as it currently exists, and following the contract expiry of generation facilities Kapuskasing CGS and Calstock CGS.

In accordance with the formalized Regional Planning Process, the Hydro-One led Needs Assessment process was conducted in parallel and assessed needs driven by customer growth. The Needs Assessment process concluded that the bulk system planning process and local planning process are most appropriate to address all the potential needs for the North/East of Sudbury region, and that there is no need for further review of this issue in the formal Regional Planning process.

Summary of Needs from the Bulk System Study

The Ontario Resource and Transmission Assessment Criteria ("ORTAC"), applicable operating limits, and market rules were used to assess the performance of the system. The ORTAC specifies maximum continuous voltage limits of 250 kV and 127 kV for nominal 230 kV and 115 kV system facilities, respectively. There are also some individual stations that have different operating limits than specified by ORTAC. The joint IESO-Hydro One team has identified that maximum voltage limits specified by ORTAC and some specific operating limits would be exceeded for the existing system during outages and system restoration. Respecting voltage limits is of critical importance for the safe and reliable operation of the power system. Therefore there is a need to install facilities to control voltages to within acceptable limits irrespective of the contract status of Kapuskasing CGS and Calstock CGS.

Should it not be possible to rely on the firm capacity of Kapuskasing CGS and Calstock CGS in the future, load customers would be supplied from additional power transfers into the Kapuskasing area through the provincial transmission system. In order to enable these greater transmission flows, there is a need to reinforce a section of circuit H9K and to provide additional voltage support in the area.

The study also found that during periods of high output from hydroelectric generation in the area, records indicate that circuit H9K has been binding and has resulted in congestion. Analysis indicates that this situation is expected to continue in the future. Therefore, reinforcement of circuit H9K is also expected to provide the added benefit of reducing congestion.

Requirement for Transmission Facilities

Based on technical and economic analysis performed by the IESO, and planning-level cost estimates received from Hydro One on February 24, 2016, the facilities outlined below are the least cost options for providing required levels of reliability, voltage performance, efficiency and operational flexibility, and must be placed in-service prior to June 2020.

1. Install a Programmable Synchrocheck Relay at Kapuskasing TS to enable breaker L21L38 to make the parallel between circuits K38S and L21S. This work is required to address existing energization needs.

2. Install a 10 Mvar (at 120 kV) reactor at the Kapuskasing 115 kV bus. To maintain required voltage levels during contingencies, this reactor must be capable of being disconnected from the 115 kV system by a cross-tripping scheme triggered by the loss of circuit L21S. This work is required to address existing energization needs, and outage conditions.

3. Increase the capability of circuit H9K between Carmichael and Spruce Falls (30 km) to provide a continuous summer rating of at least 310 A, and up to 370 A. This work is required to cover the risk of not being able to rely on the firm capacity of Kapuskasing CGS and Calstock CGS, and is also justified based on reducing congestion.

4. Install one 10 Mvar (at 120 kV) capacitor bank at the Kapuskasing 115 kV bus. This capacitor must be capable of being disconnected from the 115 kV system by a cross-

tripping scheme triggered by the loss of Spruce Falls transformer T7. This work is required to cover the risk of not being able to rely on the firm capacity of Kapuskasing CGS and Calstock CGS. If feasible, this work should include space provisions for the installation of a second future 10 Mvar capacitor bank at Kapuskasing 115 kV bus.

Please inform us of the planned in-service dates and the ultimate disposition of work, based on your scoping and project development work. We look forward to working with Hydro One in the related Connection Assessment and Approval (CAA) process for this work when your plans are finalized.

The IESO would be pleased to provide Hydro One with any required assistance in approvals processes associated with these facilities.

Yours truly,

Joe Toneguzzo
CC:
George Pessione, IESO
Ahmed Maria, IESO
Leonard Kula, IESO
Ibrahim El-Nahas, HONI

SS-11 South Nepean Transmission Reinforcement

Start Date:	Q3 2019	**Priority:**	High
In-Service Date:	Q2 2021	**3 Year Test Period Gross Cost ($M):**	38.0
Trigger(s): Customer Request			
Outcomes: Connect the South Nepean customer owned station.			

A. NEED AND OUTCOME

Investment Need

This investment is required to provide increased transmission capacity in the South Nepean area and connection to Hydro Ottawa's new transformer station. The South Nepean area is currently supplied by two Hydro Ottawa stations, Richmond MTS and Fallowfield MTS and one Hydro One distribution station Manotick DS. The stations are fed by a single 115kV circuit (S7M) which emanates from Merivale TS. The South Nepean area is expected to exceed available station capacity by 2019 and to exceed the line capacity of the 115kV circuit (S7M) by 2027. The need has been documented in both the Greater Ottawa Region Integrated Regional Resource Plan[1] and the Regional Infrastructure Plan (Exhibit B, Tab 1, Schedule 1, TSP Section 1.2, Attachment 3).

Hydro One is obligated to make connections when requested by customers. Not proceeding with this investment would be a violation of the Transmission System Code and Hydro One's Transmission License. This project is assigned a High Priority in order to meet this customer obligation.

Investment Description

The proposed project involves the:

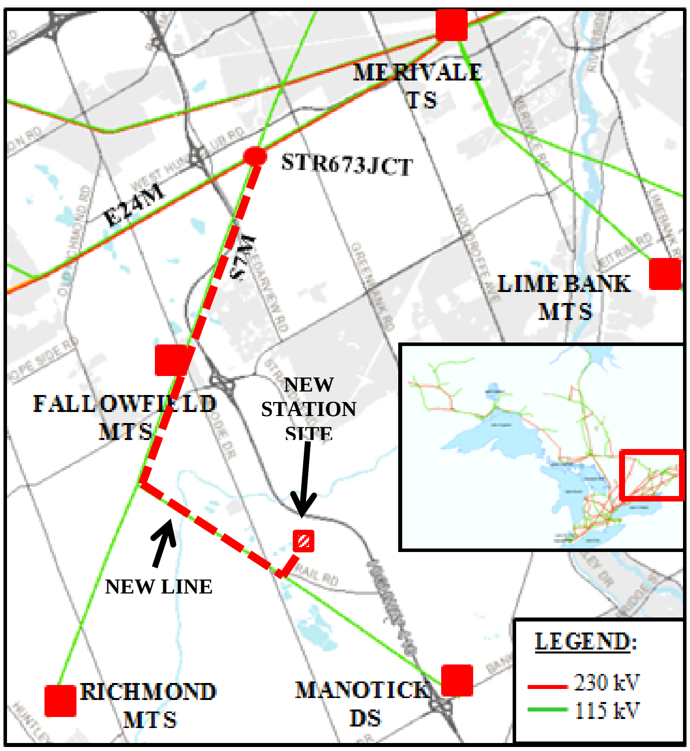
- Rebuilding of approximately 12 km of the existing 115kV single circuit line (S7M) with a new 230kV double circuit transmission line – from tower structure

[1] *http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Greater-Ottawa/2015-Ottawa-IRRP-Report.pdf*

#673 (noted as STR673JCT in the map below) to Hydro Ottawa's new station in South Nepean;

- Connection of one of the new 230kV circuits to the existing 230kV circuit (E34M) to supply Hydro Ottawa's new station;
- Connection of the other circuit of the new line to the 115kV circuit (S7M) to supply Fallowfield MTS, Richmond MTS, Manotick DS, and Hydro Ottawa's new station; and
- Modification of protection and control facilities associated with the existing circuits (E34M and S7M).

A map showing the project location is provided below.



Hydro One has initiated a Class Environmental Assessment for this project as required under the *Environmental Assessment Act*, and approvals are expected to be obtained by Q2 2019.

Witness: Robert Reinmuller

Hydro One will apply for a "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act* in Q2 2019. A summary of the need, project description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application. All land matters will be addressed in the Section 92 application.

Hydro One studies show that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment have been initiated. Both assessments will be completed by Q2 2019 to confirm the above prior to the submission of the Section 92 application.

Outcomes

This investment will provide the required increase in transmission capacity to supply load growth in South Nepean area.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Satisfy customer request for additional capacity.
Operational Effectiveness	• Improve operational flexibility and mitigate line losses by reconfiguring to a 230kV system.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the project is placed in-service subject to the terms of the Connection Cost Recovery Agreement ("CCRA"). The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 1: Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total*
Capital[1] and Minor Fixed Assets	2.3	27.5	10.5	0.0	0.0	0.0	0.0	40.3
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**2.3**	**27.5**	**10.5**	**0.0**	**0.0**	**0.0**	**0.0**	**40.3**
Less Capital Contributions	2.3	26.5	10.0	0.0	0.0	0.0	0.0	38.8
Net Investment Cost	**0.0**	**1.0**	**0.5**	**0.0**	**0.0**	**0.0**	**0.0**	**1.5**

[1] Includes Overhead at current rates.
**These project costs are based on preliminary planner estimates; the detailed cost estimates will be presented in the Section 92 application.*

C. ALTERNATIVES

Two alternatives were considered to address the transmission capacity need. This is in line with the IESO's direction (refer to Appendix "A" below) and reaffirmation of the regional planning recommendations that a 230kV connection to meet the need had system benefits.

- Alternative 1: Rebuild approximately 9 km of existing 115kV single circuit (L2M) as a 230kV double circuit transmission line from Merivale TS to Limebank MTS and build a new 6 to 8 km single circuit 230kV line from Limebank TS to provide connection to the new Hydro Ottawa station.

- Alternative 2 (Recommended): Rebuild approximately 12 km of existing 115kV single circuit (S7M) as a 230kV double circuit transmission line to provide connection to Hydro Ottawa's new station using the existing 115kV circuit (S7M) corridor.

Both Alternative 1 and 2 would address the need; however Alternative 1 was not considered further due to the cost, community impact, and complexity of securing a new right of way. Alternative 2 is the recommended alternative as it utilizes the existing 115kV circuit (S7M) corridor and is the lowest cost alternative.

D. EXECUTION RISK AND MITIGATION

The risks with respect to execution of this investment as planned would be as a result of potential delays in securing the Section 92 and environmental assessment approvals. These risks will be mitigated by initiating the Section 92 application process and environmental assessment process in a timely manner soon after customer's consent to proceed with the project. There is also a risk that the customer requirements may change resulting in a delay or cancellation of the need for this project. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer decides to cancel the project.

APPENDIX "A" – Letter from the IESO to Hydro One

ieso
Independent Electricity System Operator

1600 - 120 Adelaide Street West
Toronto, ON M5H 1T1
t 416 506 2800
www.ieso.ca

April 25, 2016

Lance Jefferies
Chief Electricity Distribution Officer
Hydro Ottawa Limited

Bing Young
Director, System Planning
Hydro One Networks Inc.

Dear Mr. Jefferies and Mr. Young,

Re: Initiating a Transmission Project for Supplying the Growing Electricity Demand in the South Nepean Area of Ottawa

The purpose of this letter is to:

- Recommend that an integrated solution, which comprises conservation and additional transmission and distribution ("wires") facilities, be pursued at this time to meet the growing electricity demand in the South Nepean area of Ottawa ; and
- Request Hydro Ottawa and Hydro One to initiate work associated with the development of a new transmission station and connection line in the South Nepean area for an in-service date of 2021.

As you are aware, a regional planning Working Group for the Ottawa area, consisting of the Independent Electricity System Operator (IESO), Hydro One and Hydro Ottawa, has been active since 2011. In 2013, the planning process was restructured to conform to the timeline and requirements of the Ontario Energy Board (OEB) formalized Regional Planning Process. In April 2015 the IESO released an Integrated Regional Resource Plan (IRRP) for the Ottawa area, documenting a 20 year plan developed by the Working Group. That plan provided forecasts of electricity demand growth in the region, identified short, medium and long-term needs, presented possible solutions, and recommended near-term actions. In December 2015 Hydro One completed a Regional Infrastructure Plan (RIP) as a subsequent step of the regional planning process.

The IRRP identified two issues affecting the western portion of the City of Ottawa which required additional planning focus. First, the more immediate need to supply demand growth in the southwest corner of the City (referred to as the South Nepean area), and second, the longer-term need to reinforce the 115 kV supply capability in the broader West Ottawa area, which includes the supply to downtown Ottawa. These areas are shown in Figure 1 below.

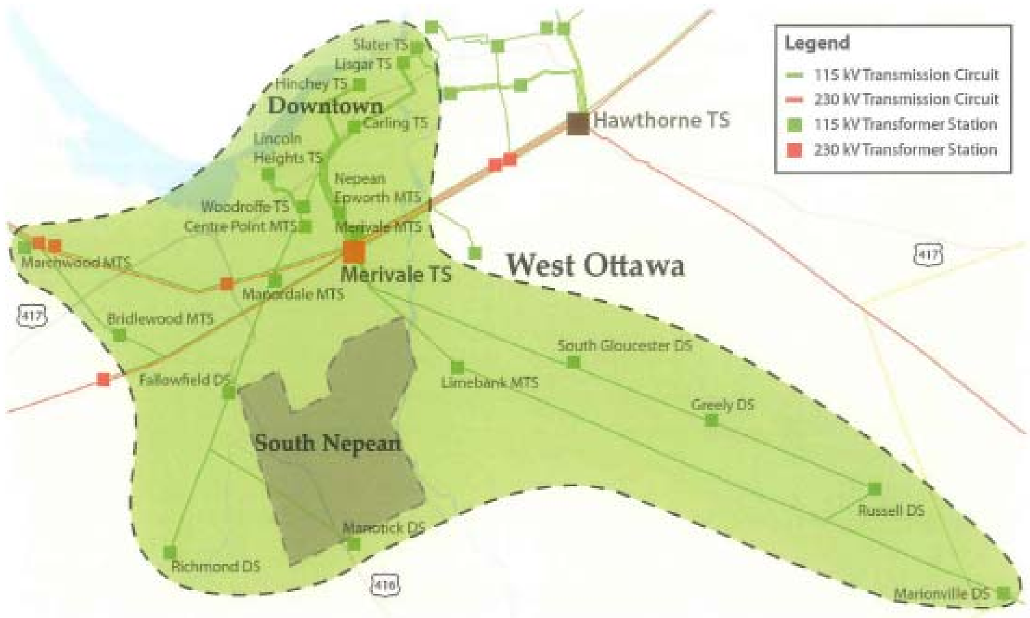


Figure 1. The South Nepean and West Ottawa areas.

While this letter is mainly focused on addressing the South Nepean issue, the proposed solution will contribute to relieving the broader West Ottawa supply issue.

Electricity Demand Growth in the South Nepean Community

For electricity planning purposes, the South Nepean service area is shown on the map in Figure 2, below. It is bounded by Fallowfield Road to the north, the Rideau River to the east, Bankfield Road to the south and Moodie Drive to the west. Hydro Ottawa, the local distribution company which serves customers in this part of the City, is forecasting robust electricity demand growth for this area. This forecast is consistent with the City of Ottawa's development plans for the area, including plans for the development of the Nepean Town Centre, the Strandherd Business Park, and residential developments that are associated with the Barrhaven South Community Design Plan, the Barrhaven South Urban expansion and Longfields Community Plan.

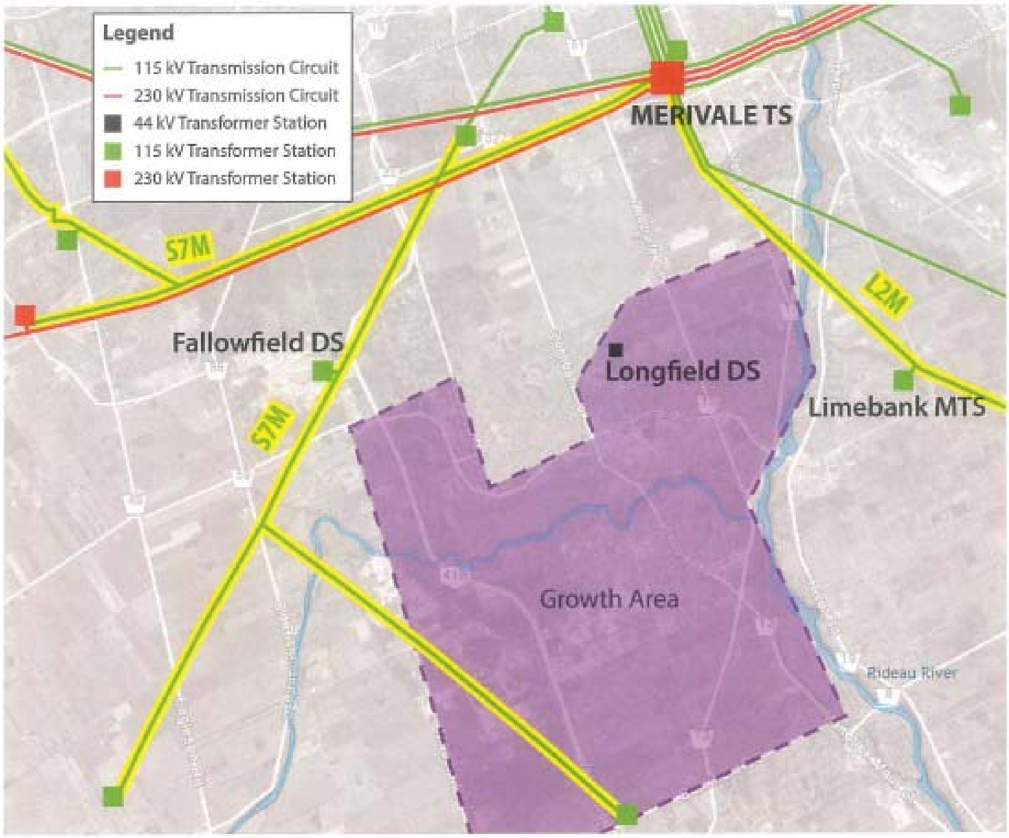


Figure 2. Electricity Supply to the South Nepean area.

The electricity demand in the South Nepean area peaked at 59 MW in the summer of 2015. Much of that demand was supplied from the provincial grid through the Merivale "hub" station in west Ottawa and delivered to the South Nepean area by two 115 kV transmission lines (S7M and L2M), and three step-down stations (Longfield DS, Limebank MTS and Fallowfield DS). These facilities are shown in Figure 2. In addition to the grid supply, there is some distributed generation connected to the three step-down stations, totaling about 7 MW, contributing to the area's supply.

The 115 kV network in the South Nepean area was originally developed to supply a relatively small number of customers in a rural area. Regional development has since given rise to significant demand growth on this legacy system as the area is being transformed into denser residential communities and commercial areas. With the forecasted growth, Hydro Ottawa anticipates the peak demand in the area to reach 88 MW by 2020 and 134 MW by 2032, an increase of about 78 MW, more than doubling today's level. This growth will place increased stress on the existing transmission and distribution infrastructure – the 115 kV line, step-down stations and distribution feeders. Over time these system elements will exceed their respective capacities.

Adequacy of Existing Supply to South Nepean

The Province's conservation initiatives are helping to manage future demand growth across the City of Ottawa. The forecast used for this planning study assumes that roughly 25% of growth in the South Nepean area will be met by increased efficiency, time of use savings, and conservation programs. Peak demand impacts associated with the aggressive conservation targets established in the 2013 LTEP were assumed before identifying the residual planning forecast, which is shown in Figure 3, below.

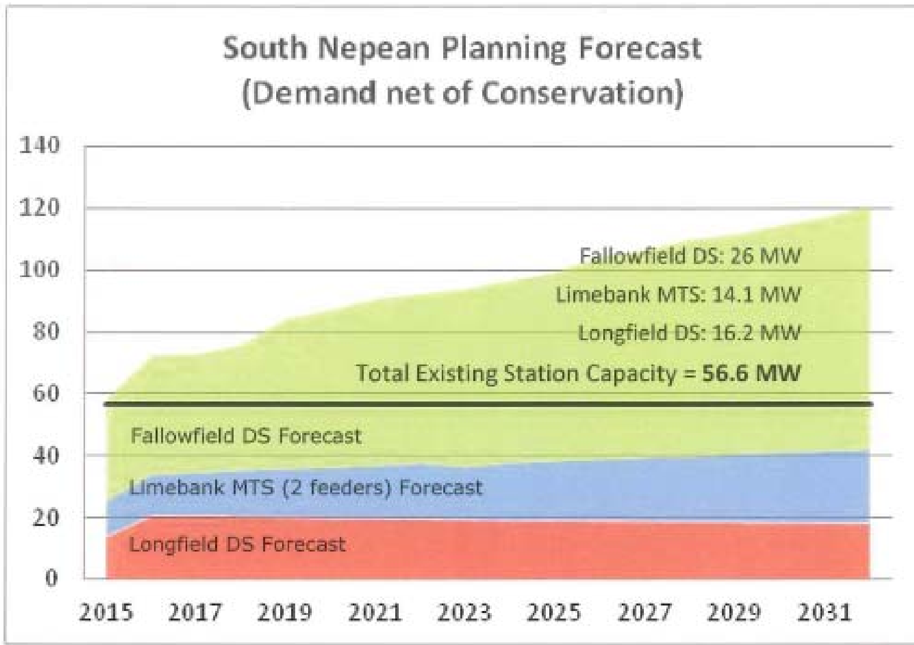


Figure 3. South Nepean Planning Forecast.

Figure 3 also shows that each of the three stations supplying South Nepean is reaching, or has already exceeded its planning capacity. Total supply capacity for South Nepean based on Hydro Ottawa's planning criteria is approximately 57 MW. This capacity is based on a combination of the ratings for the three stations, as well as the thermal ratings of individual feeders. The capability to transfer load at the distribution feeder level post contingency permits Hydro Ottawa to maintain reliable supply beyond the planning threshold, however this is not a permanent solution. Therefore, there is an imminent need to supply new connections in this growing corner of the City.

In addition to the station and feeder capacities being exceeded, the 115 kV single circuit transmission line, S7M, which provides the primary supply to this area and its surroundings, is also approaching its limit. The forecast demand on this circuit will reach its capacity of 108 MW in 2026. Therefore, solutions to relieving the station and feeder capacity constraints will also need to consider the line loading.

Solution Options Considered

Additional conservation, local generation, and transmission and distribution expansion were considered as means of increasing supply capacity in South Nepean. Given the near-term timing of the need for additional supply, in order for a solution to be feasible it must provide firm capacity in about five years, and be able to meet the total capacity need of over 60 MW by the end of the forecast period.

In order to rely entirely on conservation initiatives to provide additional capacity, more than four times the currently targeted level would need to be achieved. In terms of local generation, the magnitude of generation which would need to be connected to the distribution system in order to offset the need for additional station capacity is significantly higher than the historical uptake in the area. In addition, a distribution station like Fallowfield DS is not capable of absorbing a large amount of generation due to equipment rating limitations such as short circuit and thermal limits. New transmission connected generation in the area would not address the station limitation.

Based on the timeline and magnitude of the need for additional supply capacity in South Nepean, it is clear that it will not be feasible to address the need through additional conservation and local generation. Therefore, a new supply station and connection line are recommended for the South Nepean area.

Integrating Regional Transmission Considerations

As shown in Figure 1, South Nepean overlaps with the West Ottawa area, which is the 115 kV system supplied mainly by the Merivale hub station. A longer-term need to reinforce the 115 kV supply capability in West Ottawa was identified during the Ottawa area IRRP and in the RIP. The Merivale hub station has the capability of supplying roughly 645 MW and the 2015 peak demand in West Ottawa was 586 MW. The forecasted demand growth across West Ottawa, including the growth in South Nepean, will begin to exceed the Merivale hub capability as early as 2019. As a result of the overlap, if the new station in South Nepean is connected to the 230 kV system via a new 230 kV connection line into the area, it will take some pressure off the Merivale hub by moving demand growth off the West Ottawa 115kV system. The RIP report also reviewed potential wires solutions and indicated a preference for a 230 kV supply option if a wires solution were selected.

Community Engagement

In June of 2015 the IESO initiated the community engagement process by forming a Local Advisory Committee ("LAC") for the Greater Ottawa region consisting of eight volunteers from the community. Three meetings have been held thus far to discuss the issues which have been identified in the South Nepean and West Ottawa areas, and comments and advice have been received from the committee. Committee members generally agreed that there is a need to secure additional supply for the South Nepean area. While some LAC members support the recommended transmission solution, others feel that conservation and generation alternatives should be considered further. After consideration of the LAC's advice, transmission system expansion is nonetheless recommended, based on the magnitude and timing of the need for additional supply capacity, as well as the characteristics of the legacy system in the area. However, a broader range of solutions may be feasible to address other planning issues where there is a longer timeline and broader scope.

Summary of Recommended Integrated Plan

The IESO, on behalf of the Working Group, recommends that an integrated solution, which comprises conservation and additional transmission and distribution ("wires") facilities be pursued at this time to meet the growing electricity demand in the South Nepean area. This recommendation also contributes to a longer-term plan to address the broader needs across the West Ottawa area.

Hydro Ottawa and Hydro One are requested to initiate work associated with the development of a new transmission station and connection line in the South Nepean area for an in-service date of 2021.

The Working Group looks forward to engaging with local communities, LAC members, and the broader public while continuing to develop a long-term integrated plan for the Greater Ottawa region.

Kind regards,

Michael Lyle
Vice President, Planning, Law and Aboriginal Relations
Independent Electricity System Operator

c.c.

Terry Young, IESO
Mike Penstone, Hydro One
Ottawa Regional Planning Working Group members

SS-12 Aylmer-Tillsonburg Area Transmission Reinforcement

Start Date:	Q2 2020	**Priority:**	High
In-Service Date:	Q2 2022	**3 Year Test Period Gross Cost ($M):**	29.3
Trigger(s): Supply Reliability, Compliance			
Outcomes: Improve supply reliability to the Aylmer-Tillsonburg area.			

A. NEED AND OUTCOME

Investment Need

This investment is required to improve voltage performance and supply reliability issues in the Aylmer-Tillsonburg area. Aylmer TS and Tillsonburg TS are normally supplied by a 60 km single 115kV circuit (W8T) which emanates from Buchanan TS. The combined station summer peak load is forecast to increase from 106MW in 2016 to about 122MW by 2023.

Regional planning studies have identified a number of issues for the supply to the area:

- The HV and LV voltages at Tillsonburg TS do not meet the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"), under peak load conditions;
- The thermal ratings of a 1.5 km section of 115kV circuit (W8T) are exceeded; and
- The frequency of delivery point interruption at Tillsonburg TS falls below the minimum Customer Delivery Point performance standard.

These needs are described and documented in the London Area Regional Infrastructure Plan (Exhibit B, Tab 1, Schedule 1, TSP Section 1.2, Attachment 11). Upon the completion of the London Area Regional Infrastructure Plan, it was concluded that the transmission reinforcement will be required in order to provide voltage support and improve customer delivery performance.

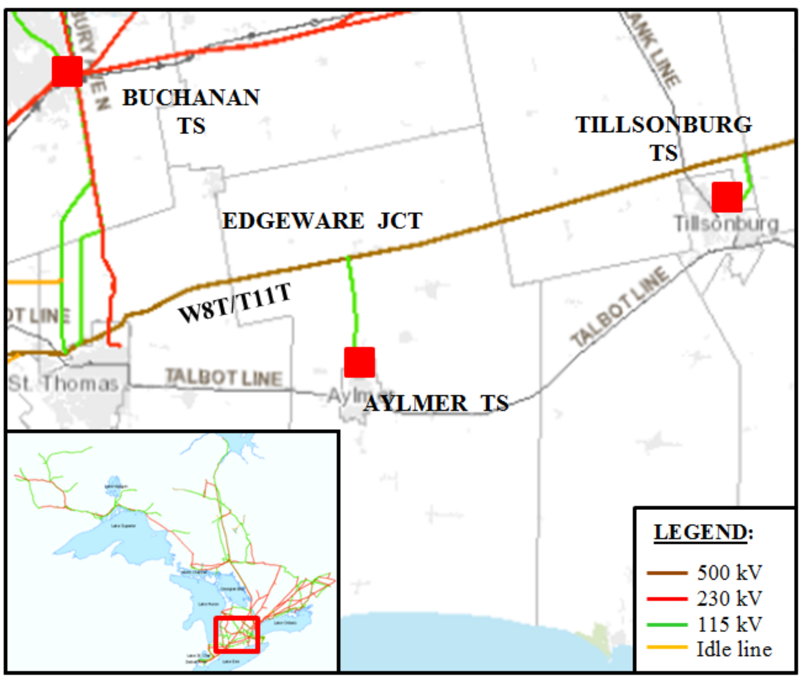
Not proceeding with this investment would result in inadequate supply capacity and reliability in the Aylmer-Tillsonburg area. This project is assigned a High Priority to improve supply to customers.

Investment Description

As per the need described above, the proposed project involves the:

- Installation of two capacitor banks on the 27.6kV bus at Tillsonburg TS to provide reactive power support; and
- Construction of 3.5 km of new 115kV single circuit transmission line from Cranberry Junction to Tillsonburg TS.

A map showing the project location is provided below.



Hydro One will apply for a “Leave to Construct” approval under Section 92 of the *Ontario Energy Board Act* in Q4 2019. A summary of the need, project description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application. All land matters will be addressed in the Section 92 application.

Hydro One will initiate a Class Environmental Assessment, as required under the *Environmental Assessment Act*, for this project in Q2 2019 with approvals planned to be obtained by Q4 2019.

Hydro One studies show that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment will be completed in 2019 to confirm the above prior to the submission of the Section 92 application.

Outcomes

This investment will address the supply capability issue and reduce risk of interruption to customers in the Aylmer-Tillsonburg area.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Improve supply reliability in the Aylmer-Tillsonburg area.
Operational Effectiveness	• Improve operational flexibility with provision of dual supply to Tillsonburg TS.
Public Policy Responsiveness	• Comply with the IESO's Ontario Resource and Transmission Assessment Criteria.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recovered from the appropriate rate pool(s) and/or capital contribution from the customers. Hydro One will be responsible for the cost of installation of low-voltage capacitors and will also partially fund the 115kV line extension to improve delivery point performance as per Hydro One's Customer Delivery Point Performance ("CDPP") Standard[1]. The remaining project cost will be recoverable through incremental revenue from the appropriate rate pool and/or capital contribution from the customers. The project costs and capital contribution amount are considered preliminary as they are only

[1] *The CDPP Standard is provided in Attachment 1 of Exhibit D, Tab 2, Schedule 1.*

finalized after the project is placed in-service, subject to the terms of the CDPP Standard and Capital Cost Recovery Agreement. The final capital contributions will be determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 1: Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	1.0	10.0	13.1	6.1	0.0	0.0	0.0	30.2
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**1.0**	**10.0**	**13.1**	**6.1**	**0.0**	**0.0**	**0.0**	**30.2**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.0**	**10.0**	**13.1**	**6.1**	**0.0**	**0.0**	**0.0**	**30.2**

[1] Includes Overhead at current rates.

C. ALTERNATIVES

Hydro One has considered two alternatives to address the voltage, thermal and customer delivery point performance needs of the sub-region. These alternatives are as follows:

- Alternative 1: Maintain a single supply to Tillsonburg TS; reconfigure existing 115kV circuits in the area by connecting W8T and T11T in parallel.

- Alternative 2: Provide a second 115kV supply by extending the existing 115kV circuit (T11T) by approximately 4 km from Cranberry Junction to Tillsonburg TS.

Both alternatives include the installation of reactive power support at Tillsonburg TS.

While Alternative 1 and 2 can both improve voltage performance and address thermal overload of the 115kV system in the local area, Alternative 1 may worsen the customer delivery point performance to Tillsonburg TS as exposure to interruption is increased due to longer length of line. The preferred option will be selected in consultation with the London Area regional planning stakeholders in Q1 2019. Cost and timeline presented above reflect that of Alternative 2.

D. EXECUTION RISK AND MITIGATION

The risks with respect to execution of this investment as planned would be as a result of potential delays in securing the Section 92 and environmental assessment approvals. These risks will be mitigated by initiating the Section 92 application process and environmental assessment process in a timely manner soon after customer's consent to proceed with the project.

SS-13 Leamington Area Transmission Reinforcement

Start Date: Q1 2019	**Priority:** High
In-Service Date: Q2 2024	**3 Year Test Period Gross Cost ($M):** 73.8
Trigger(s): Customer Request	
Outcomes: Increase load supply capability and enable customer load connection in the Leamington area.	

A. NEED AND OUTCOME

Investment Need

This investment is required to reinforce the transmission system in the Windsor – Essex region and to increase load supply capability in the Leamington area. The existing bulk transmission in the Windsor – Essex region consists of 230kV circuits (C21J, C22J, C23Z and C24Z). These circuits pass through the Leamington Junction where 230kV circuits (C21J and C22J) are tapped off to supply Leamington TS and the planned transmission-connected customer stations. Hydro One Distribution has indicated a substantial increase in requests for load connection in the Leamington – Kingsville area driven by expansion in the greenhouse sector and the existing transmission system cannot support this additional load demand. This need for transmission reinforcement has been highlighted by the IESO in the Scoping Assessment[1] as part of its development of the 2019 Windsor-Essex Integrated Regional Resource Plan.

Hydro One is obligated under its Transmission License to accommodate connections when requested by customers. Not proceeding with this investment would directly and adversely impact Hydro One's ongoing capability to reliably supply customers need in this area. This investment is assigned a High Priority given the requirement to meet customer needs in a timely manner.

[1] http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/2018-Windsor-Essex-Scoping-Assessment-Outcome-Report.pdf

Investment Description

The proposed project involves building a new 230kV switching station at Leamington Junction, and a new 230kV double circuit line between the new station and Chatham SS to reinforce the area load supply capability. A Dual Element Spot Network ("DESN") station will also be built at Leamington Junction to supply new customer load. Hydro One proposes to execute the project in two stages. Stage 1 will address the station work to facilitate customer connection and Stage 2 will address the line work, as follows:

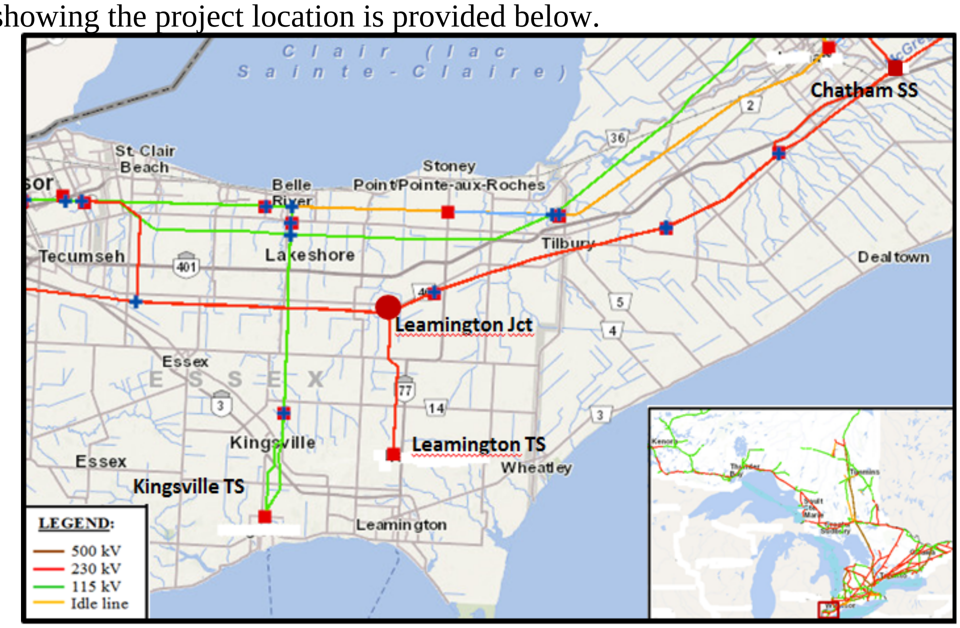
<u>Stage 1</u>: Station work (Target In-Service for Q4 2022)

- Build a new 230kV switching station at Leamington Junction and sectionalize the existing 230kV circuits (C21J, C22J, C23Z and C24Z). Connect this new switching station to the existing tap to Leamington TS; and
- Build a new 75/125MVA, 230/27.6kV DESN station with twelve feeders at Leamington Junction.

<u>Stage 2</u>: Line Work (Target In-Service for Q2 2024)

- Build a new 230kV transmission line, approximately 50 km long, from Chatham SS to the new switching station at Leamington Junction; and
- Modify Chatham SS to connect the new line into the 230kV switchyard.

A map showing the project location is provided below.



Hydro One will initiate a Class Environmental Assessment process, as required under the *Environmental Assessment Act*, for this project in Q1 2019 and approvals are expected to be obtained by Q1 2020.

Hydro One will apply for a "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act* in Q1 2020. A summary of the need, project description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application. All land matters will be addressed in the Section 92 application.

Hydro One studies show that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment will be undertaken to confirm the above prior to the submission of the Section 92 application.

Outcomes

This investment will reinforce the transmission system in the Windsor – Essex region to increase load supply capability for the Leamington area.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Satisfy customer request for additional capacity.
Operational Effectiveness	• Enhance reliability of supply in the Leamington area.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recovered from the appropriate rate pool and capital contribution from customers. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the project is placed in-service subject to the terms of the Connection Cost Recovery Agreement. The capital contributions are determined as per Hydro One's

Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 1: Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	4.9	4.9	9.7	59.1	63.8	63.8	10.0	216.2
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**4.9**	**4.9**	**9.7**	**59.1**	**63.8**	**63.8**	**10.0**	**216.2**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**4.9**	**4.9**	**9.7**	**59.1**	**63.8**	**63.8**	**10.0**	**216.2**

[1] Includes Overhead at current rates.

C. ALTERNATIVES

Hydro One considered two alternatives to provide the required additional capacity for the area:

- Alternative 1: Upgrade the four existing 230kV circuits between Chatham SS and Leamington Junction with a higher capacity conductor and build a new switching station and DESN station at Leamington Junction.

- Alternative 2 (Recommended): Build a new 230kV double circuit line between Chatham SS and Leamington Junction and build a new new switching station and DESN station at Leamington Junction.

Alternative 1 would not provide an adequate supply capacity for the longer term. It has lower supply reliability and construction will be very challenging because of the difficulty in obtaining outages. By-pass circuits will be required to ensure that existing loads can continue to be supplied while the circuits are being uprated. Alternative 2 requires building a double circuit line on a new right of way. It provides higher capacity and maintains reliability during the construction phase. Alternative 2 is therefore the preferred alternative and recommended by the IESO and Hydro One.

D. EXECUTION RISK AND MITIGATION

The risks with respect to the execution of this investment as planned would include, potential delays in securing the Section 92 and environmental assessment approvals. These risks will be mitigated by initiating the Section 92 application process and environmental assessment process in a timely manner.

SS-14 Southwest GTA Transmission Reinforcement

Start Date:	Q2 2020	**Priority:**	High
In-Service Date:	Q2 2024	**3 Year Test Period Gross Cost ($M):**	25.0
Trigger(s): Supply Reliability			
Outcomes: Increase supply reliability and support future load growth for the customers in the Southwest GTA area.			

A. NEED AND OUTCOME

Investment Need

This investment is required to increase the transfer capability between Richview TS and Manby TS to support the continued load growth in the South-West GTA area, as identified in the Metro Toronto Area Regional Infrastructure Plan (Exhibit B, Tab 1, Schedule 1, TSP Section 1.2, Attachment 8).

The 230kV transmission corridor between Richview TS and Manby TS is the main supply path for the western half of the City of Toronto. It also supplies the load in the southern Mississauga and Oakville areas via Manby TS. The corridor has two 230kV double-circuit lines (R1K/R2K and R13K/R15K) and one idle 115kV double-circuit line. The Metro Toronto Area Regional Infrastructure Plan had identified the need for reinforcing the transmission system on the South-West GTA transmission corridor by rebuilding the existing idle 115kV transmission line as a new 230kV double circuit line and connecting it to Manby TS and Richview TS.

Investment Description

The proposed project involves reinforcing the transmission system on South-West GTA transmission corridor. Hydro One proposes to execute the project in two stages. Stage 1 will address the line work and Stage 2 will address the station work in order to coordinate with future breaker replacement work at Manby TS, as follows:

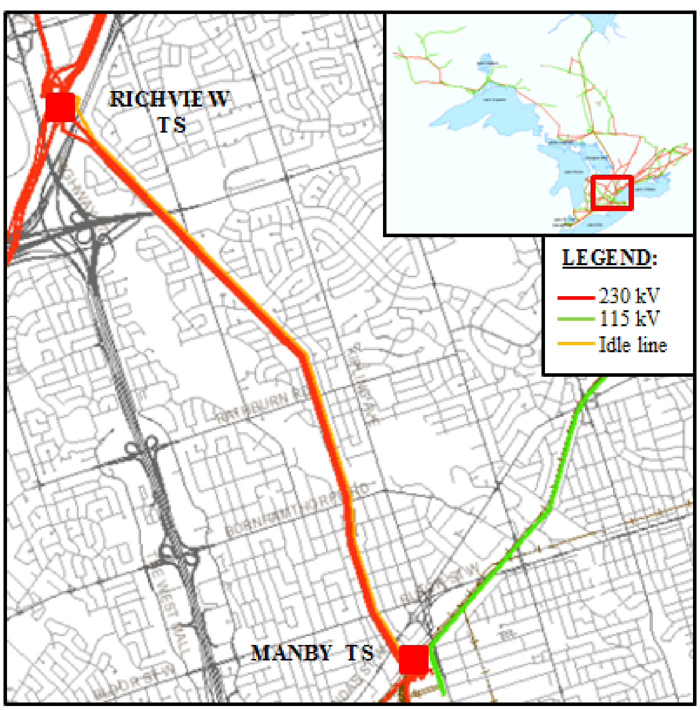
<u>Stage 1</u>: Line Work (Target In-Service for Q4 2022)

- Rebuild the existing 6.5 km idle 115kV double-circuit line as a 230kV double-circuit line;
- Connect the new 230kV conductors in parallel with existing 230kV circuits (R2K and R15K) at Richview TS and Manby TS; and
- Modify the protection and control settings at Richview TS and Manby to incorporate the new line.

<u>Stage 2</u>: Station Work (Target In-Service for Q2 2024)

- Remove the parallel connections made in Stage 1 and terminate the two new circuits into Manby TS 230kV switchyard;
- Connect new circuits at the Richview TS end to two of the existing 230kV transmission circuits from Claireville TS to Richview TS; and
- Add and/or modify protection and control equipment at Richview TS, Claireville TS and Manby TS to incorporate the two new circuits.

A map showing the project location is provided below.



Hydro One initiated a Class Environmental Assessment process, as required under the *Environmental Assessment Act*, for this project in Q4 2018 and approvals are expected to be obtained by Q3 2019.

Hydro One will apply for a "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act* in Q3 2019. A summary of the need, project description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application.

Hydro One studies show that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment will be undertaken to confirm the above prior to the submission of the Section 92 application.

Outcomes

This investment will provide the required increase in supply reliability for the customers in Toronto and southern Mississauga/ Oakville areas and support future load growth.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Ensure adequate supply capacity to support future load growth.
Operational Effectiveness	• Increase supply reliability in the Southwest GTA area.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recovered from the network rate pool as these 230kV facilities are network assets and no capital contribution is required from customers.

Table 1: Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Future Years	Total
Capital[1] and Minor Fixed Assets	2.9	10.3	7.8	6.9	3.9	2.0	0.0	33.8
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**2.9**	**10.3**	**7.8**	**6.9**	**3.9**	**2.0**	**0.0**	**33.8**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**2.9**	**10.3**	**7.8**	**6.9**	**3.9**	**2.0**	**0.0**	**33.8**

[1] Includes Overhead at current rates.

C. ALTERNATIVES

Three alternatives were considered to provide additional capacity:

- Alternative 1: Upgrade the four existing 230kV circuits between Richview TS and Manby TS with higher capacity conductor.

- Alternative 2 (Recommended): Rebuild the existing idle 115kV transmission line on the Richview to Manby transmission corridor as a 230kV double circuit transmission line and connect at Manby TS and Richview TS.

- Alternative 3: Extend the existing 230kV transmission line between Cooksville TS and Oakville TS to Trafalgar TS.

Alternative 1 provides lower supply reliability and construction will be very challenging because of the difficulty in obtaining outages. Alternative 3 requires building a line on a new right of way resulting in a higher cost. Alternative 2 is the lowest cost alternative, and maintains reliability during the construction phase. Alternative 2 is therefore the recommended alternative. This is in line with the recommended plan in the Metro Toronto Area Regional Infrastructure Plan.

D. EXECUTION RISK AND MITIGATION

The risks with respect to execution of this investment as planned would be as a result of potential delays in securing the Section 92 and environmental assessment approvals. These risks will be mitigated by initiating the Section 92 application process and environmental assessment process in a timely manner.

SS-15 Future Transmission Regional Plans

Start Date:	Program	**Priority:**	High
In-Service Date:	Program	**3 Year Test Period Gross Cost ($M):**	10.5
Trigger(s): Customer or Third Party Request			
Outcome: Respond to future regional plan projects.			

A. NEED AND OUTCOME

Investment Need

This investment is required to enable Hydro One to accommodate future transmission regional plan projects that may be triggered during the second cycle of the regional planning process, as documented in Exhibit B, Tab 1, Schedule 1, TSP Section 1.2, for which the need and scope have yet to be determined.

Regional plans are initiated based on customer needs for load supply capability and reliability. Hydro One is obligated to meet these needs when requested by customers. Not proceeding with this investment would be a violation of Hydro One's Transmission License. This investment is assigned a High Priority to ensure customer future needs are addressed in a timely manner.

Investment Description

This investment has been set up to cover future local area supply projects anticipated in the test period. These projects need and scope have not yet been identified at this time. Local area supply projects are identified during regional planning and address issues with supply facilities that connect and deliver power to a group of load stations in an area or region. Each project would be initiated based on a need identified within a Regional Infrastructure Plan.

The scope of these projects may include: new or modified transformation connection facilities, or construction of new connection lines and/or stations, and installation of breakers and/or circuit switchers. Each project would be specific to the local area and entail Hydro One to construct one or more of the above listed facilities.

Each project start is subject to obtaining all necessary regulatory and environmental approvals. The System Impact Assessment and Customer Impact Assessment will also be carried out for each project to ensure that there are no adverse impacts to the system or other transmission connected customers.

Outcomes

This investment will address specific needs for various local areas as identified in the second cycle of the regional planning process.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Ensure adequate supply capacity for the local area.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.

B. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, have been forecasted based on typical costs incurred by local supply projects over the past five year period. The project costs will be recovered from the appropriate rate pool and capital contribution from customer(s), determined on a project-by-project basis in accordance with the Transmission System Code. The project costs and capital contribution amounts are considered preliminary as they are only finalized once the project is placed in-service subject to the terms of the Connection Cost Recovery Agreement. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

The projects' actual in-service costs would be included in the rate base when the projects go into service subject to Board approval. For any projects that require "Leave to Construct" approvals, under Section 92 of the *Ontario Energy Board* Act, prudency of the expenditures will be tested during the Section 92 process.

Table 1: Total Investment Cost

($ Millions)	2020	2021	2022	2023	2024	Total[1]
Capital[2] and Minor Fixed Assets	0.0	0.0	10.5	19.6	0.0	30.1
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**0.0**	**10.5**	**19.6**	**0.0**	**30.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**0.0**	**10.5**	**19.6**	**0.0**	**30.1**

[1] Due to the in-year nature of program investments, only 2020 to 2024 expenditures are shown.
[2] Includes Overhead at current rates.

C. ALTERNATIVES

This investment will be in response to a specific need identified during the regional planning process; alternatives (if any) will be reviewed as part of this planning process.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as: the outage availability that is required for the work to be executed. These risks will be mitigated by setting a schedule that aligns with outage availability.

SS-16 Customer Power Quality Program

Start Date:	Program	**Priority:**	High
In-Service Date:	Program	**3 Year Test Period Gross Cost ($M):**	10.1
Trigger(s): Customer Engagement			
Outcomes: Improve customer power quality.			

A. NEED AND OUTCOME

Investment Need

This investment is required to mitigate the power quality impact of shunt capacitor bank switching on customers with sensitive equipment.

Shunt capacitor banks are employed on Hydro One’s transmission system for power factor correction and voltage support. Capacitor bank switching results in voltage transients and can adversely impact nearby industrial and commercial customers as variable speed drives and other sensitive customer loads are tripped. With the continued implementation of new technologies and equipment at the customer's end it is anticipated that there will be increased sensitivity to these transients by customers.

Voltage transients can be mitigated by installing a new device – the “Cap-Switcher” – to switch the capacitor bank. The device reduces the switching voltage transients and thereby significantly improves the power quality to connected customers. The significant reduction of power quality events was confirmed at recent installations.

Not proceeding with this investment would result in adverse impact on customers’ operations and satisfaction. This project is assigned a High Priority to ensure responsiveness to customer needs.

Investment Description

This proposed program involves the installation of cap-switchers at a number of Hydro One stations. The stations are selected based on the severity of the transient overvoltages experienced when switching the existing capacitor bank, as well as on the basis of feedback from customers.

The proposed plan is based on installing approximately 20 cap-switchers over a five year period. Eighteen capacitor banks at ten transformer stations (Cherrywood TS, Thornton TS, Wilson TS, St. Andrew TS, Erindale TS, Woodstock TS, Beaverton TS, Smith Falls TS, Manby TS, and Waubaushene TS) have been identified so far as requiring installation of these devices to reduce capacitor switching transients. Further studies are under way to identify the remaining cap-switcher installations locations.

Outcomes

This investment will mitigate the adverse effects of capacitor switching and improve the power quality for customers affected by switching transients.

The following table summarizes the anticipated benefits as a result of the project:

Customer Focus	• Improve customers' supply by reducing the risk of tripping sensitive loads.
Operational Effectiveness	• Reduce switching transients on the system to facilitate switching operations of capacitor banks without disrupting customer loads.

B. EXPENDITURE PLAN

The project costs, as presented in the table below, will be recovered from the network rate pool as these Cap-Switchers are network assets and thus no capital contribution is required from customers.

Table 1: Total Investment Cost

($ Millions)	2020	2021	2022	2023	2024	Total[1]
Capital[2] and Minor Fixed Assets	3.3	3.4	3.4	3.4	3.5	17.0
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**3.3**	**3.4**	**3.4**	**3.4**	**3.5**	**17.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.3**	**3.4**	**3.4**	**3.4**	**3.5**	**17.0**

[1] Due to the in-year nature of program investments, only 2020 to 2024 expenditures are shown.
[2] Includes Overhead at current rates.

C. ALTERNATIVES

No alternative was considered. This investment is in response to specific power quality concerns that have been identified by customers and for which Hydro One has committed to addressing the concerns.

D. EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of this project, such as: the outage availability that is required for the work to be executed. These risks will be mitigated by setting a schedule that aligns with outage availability.

Appendix 2-AA
Capital Projects Table ($M)

Projects	2015	2016	2017	2018	2019 Bridge	2020 Test
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
System Access						
Overhead Lines Refurbishment Projects, Component Replacement Programs and	-0.5	1.8	-0.9	4.4	2.9	0.9
Generator Customer Connection	-1.7	0.2	0.4	0.3	1.1	2.3
Load Customer Connection	7.7	13.6	42.3	28.5	41.1	21.6
P&C Enablement for Generation Connections	2.1	1.3	0.8	0.5	0.0	0.0
Sub-Total	7.6	17.0	42.7	33.7	45.1	24.8
System Renewal						
Circuit Breakers	7.1	4.1	0.4	0.1	0.0	4.1
Overhead Lines Refurbishment Projects, Component Replacement Programs and	125.4	164.0	197.2	221.2	291.9	323.9
Integrated Station Investment	374.2	469.1	481.0	410.7	336.9	405.1
Underground Lines Cable Refurbishment & Replacement	3.5	1.7	10.7	16.5	15.0	7.1
Power Transformers	43.5	13.0	0.0	-0.7	0.1	0.0
Other Power Equipment	12.5	5.3	0.0	0.3	0.0	0.0
Protection and Automation	60.2	40.5	20.9	44.4	72.8	77.7
Ancillary Systems	17.1	7.6	1.1	0.7	0.0	0.0
Site Facilities and Infrastructure	14.5	2.2	2.2	0.3	0.0	0.0
Stations Environment	3.8	1.9	0.4	0.0	0.0	0.0
Tx Transformers Demand and Spares	27.2	24.6	26.8	82.6	56.6	47.4
Sub-Total	688.9	733.9	740.7	776.2	773.3	865.2
System Service						
Inter Area Network Transfer Capability	86.3	80.8	36.0	48.9	54.9	121.0
Local Area Supply Adequacy	64.9	54.3	45.1	20.7	39.0	73.9
Smart Grid	3.5	3.3	0.7	0.2	0.0	0.0
TS Upgrades to Facilities Distribution Generation	-1.2	0.0	0.0	0.0	0.0	0.0
Performance Enhancement	1.3	0.4	0.0	0.0	0.3	0.3
Risk Mitigation	3.1	1.8	9.5	2.6	5.4	4.7
Power Quality	0.0	0.2	2.3	1.4	4.1	4.2
Sub-Total	157.9	140.9	93.5	73.9	103.8	204.1
General Plant						
Facilities & Real Estate	22.7	13.9	6.7	7.0	7.2	8.1
Grid Operating and Control Facilities	14.2	7.6	6.0	3.8	37.4	35.3
Information Technology (including Cornerstone)	21.6	35.9	32.8	42.0	33.7	25.7
Operating Infrastructure	1.4	4.6	4.8	5.8	10.2	21.1
Other (including CDM)	0.7	0.3	-1.1	-0.7	0.0	0.0
Site Facilities and Infrastructure	5.9	8.1	10.8	16.4	12.0	9.4
Transport and Work & Service Equipment	22.1	24.6	16.9	9.3	15.9	15.8
Sub-Total	88.6	94.8	76.9	83.6	116.3	115.4
Progressive productivity Placeholder						-17.0
Directive Adjustment *					-0.3	-0.3
Total	**943.0**	**986.7**	**953.9**	**967.3**	**1,038.2**	**1,192.2**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*						
Total	**943.0**	**986.7**	**953.9**	**967.3**	**1,038.2**	**1,192.2**

Notes:

* The Directive Adjustment reflects the impact of the directive issued by Ontario's Management Board of Cabinet on February 21, 2019 and the associated compensation framework they approved on March 7, 2019. Refer to Exhibit F, Tab 4, Schedule 1 for further details.

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2020*

CATEGORY	**Historical Period** (previous plan[1] & actual)															**Forecast Period** (planned)				
	2015			**2016**			**2017**			**2018**			**2019**			**2020**	**2021**	**2022**	**2023**	**2024**
	Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual[2]**	**Var**					
			%			%			%			%			%					
System Access	19.7	7.6	-61%	31.9	17.0	-47%	33.3	42.7	28%	24.3	33.7	39%		45.1	--	24.8	11.3	11.7	12.7	4.1
System Renewal	573.6	688.9	20%	539.9	733.9	36%	733.7	740.7	1%	780.4	776.2	-1%		773.3	--	865.2	1,103.1	1,172.8	1,177.4	1,193.8
System Service	189.9	157.9	-17%	180.0	140.9	-22%	97.0	93.5	-4%	75.6	73.9	-2%		103.8	--	204.1	148.2	151.8	174.3	204.2
General Plant	116.3	88.6	-24%	114.6	94.8	-17%	86.0	76.9	-11%	119.7	83.6	-30%		116.3	--	115.4	94.4	94.7	83.6	58.9
Progressive Productivity Placeholder																- 17.0	- 39.0	- 61.0	- 78.0	- 91.0
Directive Adjustment														- 0.3		- 0.3	- 0.3	- 0.4	- 0.4	- 0.4
TOTAL EXPENDITURE	899.4	943.0	5%	866.3	986.7	14%	950.0	953.9	0%	1,000.0	967.3	-3%	-	1,038.2	--	1,192.2	1,317.7	1,369.6	1,369.6	1,369.6
System OM&A	$ 431.2	$ 441.6	2%	$ 436.8	$ 408.1	-7%	$ 397.7	$ 385.0	-3%	$ 394.3	$ 419.2	6%		$ 356.5	--	$ 375.8	*	*	N/A	N/A

* System OM&A includes Operations, Maintenance and Administration expenses. System OM&A for 2021 and 2022 is determined based on the escalation factor identified in Exhibit A, Tab 4, Schedule 1

** 2019 is Bridge Year Forecast

*** The Directive Adjustment reflects the impact of the directive issued by Ontario's Management Board of Cabinet on February 21, 2019 and the associated compensation framework they approved on March 7, 2019. Refer to Exhibit F, Tab 4, Schedule 1 for further details.

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

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Exhibit B, Tab 1, Schedule 1 ("TSP") Section 3.3

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

TSP Section 3.3

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

TSP Section 3.3

CAPITAL WORK EXECUTION STRATEGY

1. INTRODUCTION

Hydro One has the ability to successfully execute large capital work plans and reduce the variability of its capital and in-service additions. Because of the implementation of new or improved initiatives and capital delivery processes, Hydro One will continue to improve on its past performance. These initiatives and processes include:

a) Hydro One project managers oversee project delivery early in the process, beginning at the Project Scoping phase. This reduces the number of project changes made in the Execution phase and provides a consistent and accountable vision of the project throughout its lifecycle;
b) Hydro One re-configured its Primavera 6 scheduling tool to develop standardized project schedule reports and standardized cost and performance comparisons on an aggregate basis;
c) Hydro One adopted the American Association of Cost Engineers ("AACE") estimating framework, which is an industry established cost estimating classification system which allows the company to standardize its approach to estimating and project planning;
d) Hydro One has implemented a new risk definition and management program;
e) Hydro One has improved its change management process to more accurately track costs and forecast and communicate variances in resourcing and cash flow; and
f) Hydro One has introduced a number of new reporting and governance frameworks that provide greater transparency into and accountability for the capital delivery program.

Hydro One's work planning and execution activities focus on the company's business objectives including safety, quality, efficiency, and meeting customer commitments. As a result, Hydro One takes an efficient, adaptable approach to its capital work program, which gives it flexibility to accommodate new circumstances that may arise over the course of a multi-year project such as outage constraints, external approvals, material delivery, site conditions, evolving customer needs, changing priorities, and emergent investments. Hydro One is committing to executing its proposed capital work program using the process and framework set out herein.

2. IMPROVEMENTS OVER TIME

Hydro One has demonstrated its ability to improve on the execution of its work program while reducing the variability of its capital and in-service additions. Table 1 below shows the five-year variance between approved and actual capital and in-service additions between 2014 and 2018. Over the past five years, the company placed $4,556.4 million in-service with an overall variance of 3.5% and modest variances in 2018 when Hydro One placed $1,160.4 million in-service demonstrating its ability to meet its target at a portfolio level. Indeed, the company's recent performance reflects the initial effects of the improvements described in the introduction and further described in section 5 below.

Table 1: Capital and In-Service Additions Performance ($ millions)

	Capital Expenditures		**In-service Additions**	
	Actual	**Approved**	**Actual**	**Approved**
2014	844.7	899.2	914.5	863.3
2015	943.0	899.4	699.1	821.3
2016	986.7	866.3	910.2	673.3
OEB-Approved Cumulative ISA Total for 2014-2016[1]	2,774.4	2,664.9	2,523.8	2,357.9
2017	953.9	950.0	872.2	867.7
2018	**967.3**	**1,000.0**	**1,160.4**	**1,178.4**
Total (2014 to 2018)	**4,695.4**	**4,614.9**	**4,556.4**	**4,404.0**
5-Year Variance	**1.7%**		**3.5%**	

Throughout 2017 and 2018, Hydro One achieved $2,032.6 million of in-service additions which is within 1% of the OEB-approved plan total for those years, demonstrating its ability to achieve results very close to target at a portfolio level.

3. RESOURCES TO EXECUTE

To execute the capital portfolio over the test period, from 2020 to 2022, Hydro One has a range of resources available to it. Hydro One has internal resources, manages a direct-hire casual building trades workforce and is able to supplement these resources through contracts with qualified service providers. Hydro One contracts a variety of services to

[1] In 2016, Hydro One placed $910.2 million in-service to achieve the OEB- approved cumulative 2014 to 2016 in-service additions of $2,357.9 million. The 2016 actuals are in-line with the 2016 "Bridge Projected" in EB-2016-0160, Exhibit D1, Tab 1, Schedule 2, Table 1 with a variance of $1.5 million dollars. The Bridge Projected for 2016 was $911.7 million.

help deliver its capital work program including: third party Engineer, Procure, Construct ("EPC") services for select projects; specialty construction skills that are not retained within Hydro One (i.e. tunnelling, high voltage cable installation); and specialty equipment rentals with operators (e.g. cranes, day lighting / vacuum trucks). In January 2017, as part of the strategic vision to build partnerships in the construction industry, Hydro One identified qualified service providers for line refurbishments, buildings, substations and high voltage cable work. Hydro One uses a competitive Request For Proposal ("RFP") process to select from the qualified service providers for particular work.

4. CAPITAL DELIVERY PROCESS

Hydro One's capital delivery process is illustrated in Figure 2 below and is comprised of three key stages: (i) Planning; (ii) Project Definition, which includes Project Scoping and Project Planning; and (iii) Execution, which includes Project Execution and Project Close. Each project has a "Primavera 6" or "P6" schedule that is refined throughout the process comprised of scope, schedule and cost elements and must pass through certain stage gates before proceeding to the next phase. Cost and schedule accuracy improves throughout the process, which is further described below.

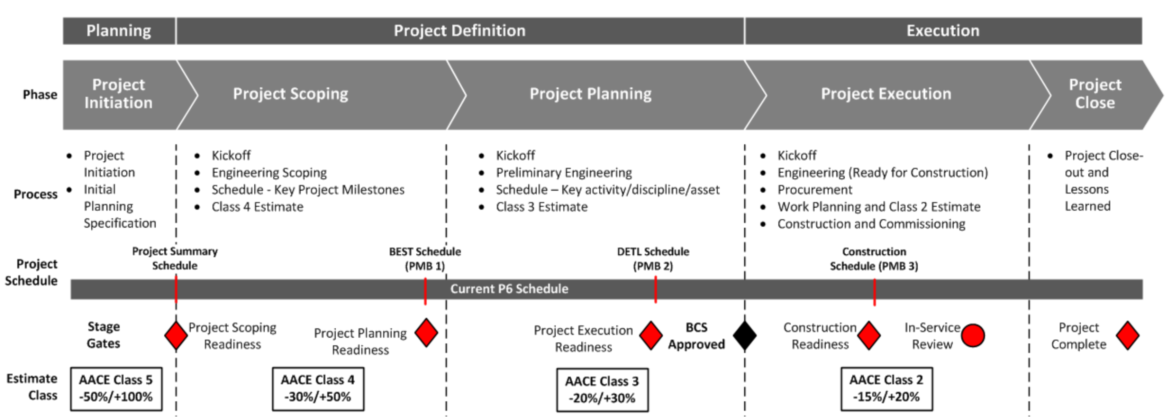


Figure 2: Transmission Capital Project Delivery Model

In early 2017, Hydro One made improvements to its capital delivery process, primarily in the Project Definition phase. These are described in section 5 below. These initiatives will result in greater efficiencies in execution when projects reach the Execution phase.

4.1 THE PLANNING PHASE

The Planning phase coincides with Hydro One's Investment Planning process as described in the TSP Section 2.1. During the Planning phase, Hydro One identifies project needs, develops a high-level project scope and prioritizes investments using its risk-based methodology. Lines of business are included in the planning process to ensure the investment plan is realistic and achievable, to clarify assumptions and to identify interim milestones for the subsequent Project Definition phase so the company can monitor its progress and identify challenges earlier in the process. As a result of this work, a high-level project summary schedule and cost forecast are identified using a unit price catalogue and/or comparator projects. The cost forecast is within the range of an AACE Class 5 estimate (minus 50% to plus 100%).

4.2 PROJECT DEFINITION PHASE

Project Definition consists of two phases: Project Scoping and Project Planning as further described below. This phase is led by project managers who lead a cross-functional team of Hydro One professionals with functional accountabilities including engineering, project controls, real estate, environmental approvals and compliance, construction services, system operations, and maintenance workgroups, as well as lines of business representing customers, communities (including First Nations and Métis communities) and external agencies.

In each of the Project Scoping and Project Planning phases, the scope of work and project execution plan may be further refined including: the work plan, the integrated project schedule and cost estimates (including risk registers and basis of estimate). As more work is completed, estimates improve and potential variability decreases.

4.2.1 PROJECT SCOPING

The objective of Project Scoping is to finalize the scope of work. Alternative designs may be identified and evaluated during this phase to assist in this process.

The project manager conducts a site meeting with the project team to review the constructability, operability, maintainability, safety and environmental impacts of the project. This gives Hydro One an opportunity to identify any outage requirements or incremental scope such as components that may need to be made compliant with applicable standards. Hydro One also identifies long-lead materials requiring procurement or environmental assessment requirements to be completed during the subsequent Project Planning phase. Anticipated execution risks and potential outage issues arising from customer constraints or geographic concerns may also be incorporated into the project plan in this phase. At the end of this phase, a preliminary project execution plan is completed which contains an estimate based on unit cost and a schedule which identifies relevant milestones selected from a pre-determined list. The project must also pass through the Project Planning Readiness stage gate before proceeding to the next phase.

An AACE Class 4 estimate with an accuracy range of minus 30% to plus 50% is prepared using unit cost-based estimates and available site specific information. The maturity level of the project definition deliverables is in the order of 15% complete.

4.2.2 PROJECT PLANNING

In Project Planning, Hydro One prepares a project execution plan that captures the scope, schedule and cost requirements and identifies risks that have the potential to change the project scope, schedule or cost. During this phase Hydro One may conduct preliminary community engagements. The project execution plan includes the following items, as referenced in the capital delivery process diagram at Figure 2:

- Schedule: a more comprehensive schedule is prepared at this point identifying key activities by discipline and asset (for instance timeframe to construct foundations, breakers, transformers, etc.);
- Risk workshop: to quantitatively analyze risk and develop project contingencies, a risk workshop is conducted for all projects over $10 million to identify the potential likelihood and consequence of project risks materializing, which informs the project contingency;
- Outage plan: a preliminary outage staging plan is prepared to identify work being executed each year, elements that may have to be taken out of service, system constraints, and contingency plans or bypasses if an outage is not an option; and
- Engineering package: At the conclusion of this phase, all major material and engineering studies and surveys are complete and basic layout drawings including the phasing of work are determined.

This package is reviewed by the project delivery team as part of the Project Execution Readiness stage gate.

Between the Project Planning and Execution, the final plan is reviewed and approved by senior management. Upon approval, it is largely expected that the project will be executed per scope, cost and timeline set out in the project plan, within the estimate accuracy range (as described in the paragraph below).

An AACE Class 3 estimate with an accuracy range of minus 20% to plus 30% is prepared using information provided in the engineering deliverables and project execution plan. The maturity level of deliverables in the project definition phase is in the order of 25% complete for stations projects and up to 75% complete for lines projects.

4.3 EXECUTION PHASE

In the Execution Phase, work moves through the Project Execution and Project Close sub-phases. Project Execution contains three steps: (i) detailed engineering and procurement; (ii) construction; and (iii) commissioning, as set out in Figure 2 above and described below.

4.3.1 PROJECT EXECUTION - DETAILED ENGINEERING AND PROCUREMENT

In this phase, detailed design packages are developed and issued for construction, environmental approvals are obtained and major equipment is procured. Once most of the production engineering work is complete, a significant component of variability is removed from the project and it is reasonable to expect that the cost, planned accomplishments, and schedule milestones will be met within the specified tolerance, barring extraordinary circumstances.

4.3.2 PROJECT EXECUTION - CONSTRUCTION

Starting in 2018, Hydro One will take the opportunity to review its ready for construction civil engineering packages, update its plan and verify it costs before moving into construction where errors and changes are expensive and could cause delays.

In Project Execution, the project is built to the required technical standards and detailed engineering specifications. The project manager is responsible for coordination of all contributing workgroups to deliver the work plan on time and in a manner that is safe and cost effective. The project manager monitors the work plan through regular communication with construction; manages change order requests if required; ensures the timely delivery of material, equipment and drawings; and provides monthly cost, schedule and work accomplishment (scope) updates on the project for the purposes of month-end reporting as described below in section 5.3 under Portfolio Management. Detailed job planning and daily onsite planning meetings are used as key communication tools during the process from site preparation and civil/electrical work to major equipment installation and site remediation activities to ensure the safe execution of planned work.

4.3.3 PROJECT EXECUTION - COMMISSIONING

When construction is complete, the project is handed to the Station Services and Operating divisions for formal site acceptance testing and commissioning before the asset is transferred to the Ontario Grid Control Centre. This step ensures quality, safety, efficiency and readiness of the new assets.

4.3.4 PROJECT CLOSURE

The project closure process was introduced as a new stage gate in 2018 to ensure that all post in-service project closure activities were completed within agreed upon timelines. This will ensure that the newly built or refurbished assets are transitioned into operations in a timely manner and that all records, drawings and systems are updated to reflect the assets as-built.

A site meeting is held for capital projects with a budget of $5 million or greater to review project objectives, ensure they have been met and to discuss ‘lessons learned’. The project closure process engages key individuals who participated in the capital work program life cycle to ensure knowledge transfer for future projects and to reinforce a culture of continuous improvement.

5. PRODUCTIVITY AND EFFICIENCY IMPROVEMENTS – PROJECT DEFINITION

Hydro One has recently undertaken a number of initiatives to increase the effectiveness and efficiency of its capital work program delivery. These initiatives are described in the following sections.

5.1 PROJECT MANAGEMENT

In April 2017, Hydro One aligned project management accountabilities under one team. Project Delivery Managers (“PM”) were identified as being accountable for a project at the beginning of the Project Scoping phase rather than previously at the Project Execution phase. This reduced the handoffs in the project lifecycle and provided a consistent approach to execution planning thereby giving the PMs the authority to design the project execution plan from the beginning, with the input of all supporting lines of business, rather than after the budget and schedule is defined. This will lead to earlier recognition of potential project issues and risks and increase the likelihood of delivering projects on scope, schedule and cost with acceptable levels of change.

5.2 PROJECT CONTROLS

Hydro One's Project Controls office has made improvements to its processes and tool suite for the following: (i) estimating; (ii) scheduling; (iii) project change management; and (iv) risk management.

Estimating: In 2017, Hydro One adopted the AACE Classification Scheme which is an industry-established estimating classification scheme intended to appropriately communicate and set expectations for estimate accuracy by project phase based upon the maturity of underlying deliverables associated with planning/engineering/construction work that has been completed. Hydro One is working on a quality assurance process using the AACE methodology to ensure the inputs and outputs of each phase are consistent. Hydro One is also in the process of capturing a performance measurement baseline estimate and schedule at the end of each phase to be compared to actual results to ensure that the mapping is accurate. This baseline will also improve the lessons learned process as it will provide a consistent time and value to compare back to.

Scheduling: In 2017, Hydro One rebuilt and refreshed its Primavera P6 scheduling tool introducing standardized project schedule reports to improve the communication of schedule information at each phase of the capital delivery plan. A new standard work breakdown structure has been applied consistently together with a defined set of business rules and standard templates for all new investments transitioning to the Execution phase. This will ensure that the work is scheduled the same way, and at the same level of detail, that it is estimated and executed at. A standard set of project milestones have been developed that will allow standard portfolio and project views of projects to proactively see issues, enable resource planning and scheduling, as well as quickly monitor portfolio/project performance. Hydro One will now use P6 to capture schedule information during the Project Definition phases, define the appropriate level of detail required at each phase in the delivery model and conduct internal benchmarking across similar projects.

Change Management Process: Enhancement of cost control and change management processes is an ongoing initiative. Hydro One has improved its change management process to allow project teams to more accurately track costs, forecast and communicate variances in resourcing and cash flow both during a project and at project close. Improvements include a new simplified and standardized work breakdown structure on all new investments starting in Q4 2017. A new cost controller role was created to build out SAP for cost control and reporting utilizing the new work breakdown structure. The project manager is now supported by cost controllers and cost reports are generated with the new work breakdown structure to assist with project forecasting and reporting variances.

Risk Definition and Management Program: Hydro One implemented a new robust risk definition and management program for projects with a gross total estimated cost of more than $10 million. This risk program reviews scopes, execution plans and schedules to identify potential likelihood and consequence of project risks materializing, which is used to quantitatively analyze risk and develop project contingency using a predictive modeling and optimization tool. Project risk mitigation plans are also developed at this stage. Each project is subject to a risk review meeting to develop the project-specific risk registry. The risk review meeting includes Hydro One representatives from across the organization to provide full representation of different corporate mandates. Early, integrated review and mitigation planning allows greater control of project variances by anticipating issues and planning for the responses (actions and funds) as opposed to reacting and not having planned for the cost and/or schedule impacts. For smaller projects, a risk registry is created. However, a formal workshop and predictive modeling is not required.

5.3 TRACKING AND REPORTING

As part of its capital delivery process, Hydro One has established the mechanisms below to enable appropriate tracking and reporting of project progress.

Reporting on Project and Program Status: Hydro One reviews its project and program status on a monthly basis. Projects in the Project Definition phase that are planned for construction in the next one to three years are reviewed from a readiness perspective. Projects that have significant capital or in-service additions in the year are reviewed from an execution perspective. Hydro One uses a combination of standard reporting requirements, key performance indicators, change management approval processes, both at the project and portfolio level to provide assurance that projects are being well managed. This allows Hydro One to respond to a changing landscape as projects naturally encounter changes, such as outage constraints, delays in external approvals, material delivery delays, site conditions, customer needs, priorities and emergent investments.

Contingency Reviews: As discussed in Attachment 1 of Exhibit A, Tab 2, Schedule 4, Hydro One regularly reviews the amount of contingency held within each portfolio along with future year capex and in-service addition assumptions. The review considers the project and the associated risk to determine appropriate contingency amount to hold in the portfolio.

Portfolio Management: Project managers provide a multi-year forecast for all work in Execution and starting in 2018, they are providing a multi-year forecast for work that is in Project Planning where an estimate has been completed. Hydro One reviews its capital budget and ISAs on a two-year rolling basis and for projects in the execution stage, Hydro One reviews ISAs on a multi-year basis. This allows the company greater flexibility to plan and reschedule projects within a two-year rolling window. Project managers forecast multi-year in-service additions and report partial in-servicing to optimize portfolio management resulting in minimized interest costs for assets under construction. This allows Hydro One to foresee and track the impact of in-year changes on future years.

Redirection: Redirection refers to a process where there are changes in the investments forming part of Hydro One's business plan. In January of 2018, Hydro One introduced a Redirection Committee at the executive level to oversee the redirection process whereby changes to investments relative to those in the business plan are approved, documented, and communicated to stakeholder line management. This standardizes the process for expenditure adjustments to capital, Operations, Maintenance & Administration ("OM&A"), and in-service additions. The Committee provides direction on required investment adjustments to the business plan to address emerging business needs/risks or to seize opportunities related to the planning and execution of Hydro One's investment plan to ensure that Hydro One meets the commitments set out in its investment plan. The committee reviews adjustments to the current year and any future year impacts will be documented and incorporated into the annual investment planning process.

Stage Gate Approvals: Projects must pass stage gates before moving to the next phase in the capital delivery process. The stage gate review process provides senior management with visibility into current project performance, risks and issues allowing for proactive adjustments in project delivery and/or project budgets if required. Projects which pass stage gates are considered able to meet the schedule and cost outcomes presented within the estimate accuracy bands for the current level of project development.

6. PRODUCTIVITY AND EFFICIENCY IMPROVEMENTS – PROJECT EXECUTION

The benefits of introducing upstream efficiencies in the Project Definition phase as well as the evolution of the company's delivery model strategy will result in tangible downstream improvements. Field workforce productivity will benefit from improved project planning, engineered drawing timeliness, material delivery certainty and outage and staging plan optimisation. Throughout 2019 the focus will turn to efficiency initiatives relating to downstream work practices and capturing the benefit of improved project planning. As discussed in TSP Section 1.6, the company has a placeholder of $704 million in productivity savings over the plan period (2020-2024) in its Capital and OM&A programs. This includes a placeholder of $117 million in progressive productivity savings to be realized over the 2020-2022 test period as discussed in detail in TSP section 1.6. Hydro One anticipates that the improvements and efficiencies described in this exhibit will contribute to identifying and defining further progressive productivity savings. Specific initiatives will be identified throughout the test period and may include better utilization of tools, improved processes and design to reduce labour and materials, and the optimization of commissioning work.

7. SAFETY INITIATIVES

Hydro One continually launches safety-related improvement initiatives, in-line with the value the corporate culture places on safety. As shown in Figure 4, these initiatives have resulted in a steady decrease to the recordable injury frequency per 200,000 hours worked by the groups primarily accountable for the execution of the capital work program, Stations Construction and Transmissions Lines, at the same time that the overall work program has grown substantially. The most severe incidents are classified as high Maximum Reasonable Potential for Harm (high MRPH) and have also shown an improving trend over recent years.

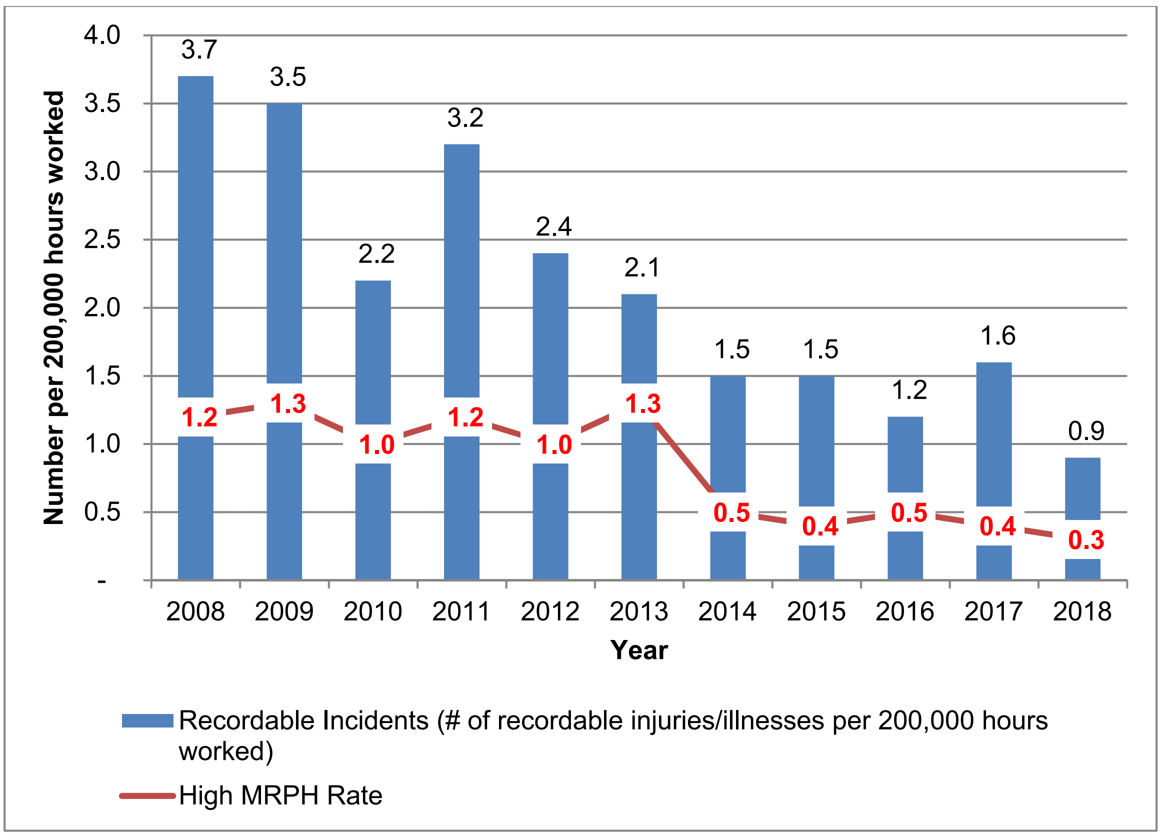


Figure 4: Recordable Injury Frequency per 200,000 Hours Worked (Capital Work Execution, Tx Construction Services & Tx Maintenance)

Hydro One continues to focus on the implementation of its annual Health, Safety and Environment (HSE) initiatives and programs to improve its health and safety culture including the Journey to Zero, Leadership Commitments and the engagement of employees.

The overall safety theme in 2019 is "Safety Culture Brand Campaign" which emphasizes human performance and distractions as the largest contributing cause for most incidents with the goal of improving risk-based decision making. Every year Hydro One conducts safety risk assessments to identify the risks that are most probable and have the highest impact with a view to developing initiatives to address them. The safety campaign was developed by Hydro One with support from a third-party expert and will launch a new Safety Brand in the first quarter, along with training and communications for five Human Success principles that each Hydro One employee will receive. As well Hydro One will focus on the development of leadership by providing training for all managers in communication skills for the positive delivery of safety messages in the field. Throughout the year in monthly Safety Communication Packages themed topics will focus on high risk practices, while providing tools and guidance to eliminate and bring awareness to our highest risk activities. In 2019, the focus will be on the following areas: People Development, Leadership Skills, Human Success Principles and the reduction of lacerations.

Hydro One will continue to conduct safety roll-outs to the field crews in both the first and third quarters of 2019. The safety roll-outs allow senior management to reinforce the company's commitment to safety and ensure that corporate targets and goals are communicated consistently. The safety roll-outs focus on driver safety, including Hydro One Safety Rules governing driving, vehicle collision avoidance practices and techniques; job planning; and recent incidents to provide lessons learned using real and relatable examples.

There is an increased focus to have visible leadership in the field; an increased manager presence during work place observations as well as actively seeking opportunities for coaching/mentoring. Managers and above are expected to participate in the workplace safety observations and in-cab assessments of their staff supervisors and increase site visits to provide additional feedback to staff on their work practices from a safety perspective.

Hydro One has made improvements to the job planning function with the overall goal of improving engagement at the working level. Weekly safety bulletins are distributed and shared with staff at the Monday morning tailboard sessions. This ensures that the discussions include relevant and fresh topics to share with staff. Once per month the topic includes driver safety tips. Daily onsite planning meetings are expected at the start of the day and after breaks to refocus field staff on critical hazards and reinforce safe and effective work practices. The use of open-ended questions is encouraged to generate good discussion and to ensure that everyone is heard. Crews participate in warm-up/stretch sessions during the course of the day as needed to reduce the occurrence of musculoskeletal injuries.

8. SUMMARY

Hydro One has demonstrated that it can execute a very large work program while maintaining the needed flexibility to accommodate required adjustments in its capital work plan due to changing priorities, project challenges and emergent investments. The improvement initiatives discussed in this exhibit have been carefully selected to ensure that the company can conduct an increasing work program in a cost-effective, safe and reliable manner. The transmission capital work execution strategy will result in greater effectiveness throughout the stage-gate process and increased accuracy in forecasting work and timelines. A continued focus on the business objectives of the transmission system plan including safety, quality, efficiency, and meeting customer commitments will ensure Hydro One's success in accomplishing its capital work program.