TRANSMISSION ASSETS AND INVESTMENT STRUCTURE

1.0 INTRODUCTION

Sustaining programming for Operating, Maintenance and Administration (OM&A) and Capital is developed to meet Hydro One’s strategic objectives and performance targets that are described in Exhibit A, Tab 4, Schedule 1, Section 3 - Summary of Transmission Business.

This exhibit provides a summary and additional information concerning the OM&A and Capital investment structure submitted with Exhibit C1, Tab 2, Schedule 3 and Exhibit D1, Tab 3, Schedule 2 respectively.

As well, Appendix A of this exhibit provides a detailed description of the transmission assets that are managed by Hydro One.

Asset-specific information on the decision making process for sustaining investments can be found in Exhibit D1, Tab 2, Schedule 1.

2.0 TYPES OF SUSTAINMENT WORK

Sustainment programming for OM&A and Capital involves decision making that determines the appropriate level of investment to meet Hydro One’s objectives. While the specifics of the kinds of work differ amongst the assets involved, it is possible to identify broad categories of work that apply to Sustaining activities.
2.1 SUSTAINMENT – OM&A WORK

The following are the categories of Sustaining OM&A work that are typically defined and executed at Hydro One:

Planned Preventive and Corrective Maintenance: includes scheduled (time based) and condition based Preventive Maintenance (PM), as well as planned corrective maintenance. In addition, it can include targeted asset condition assessments.

Planned maintenance is conducted to meet Hydro One’s obligations defined by the Transmission System Code to “inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments”. Planned Maintenance for P&C is defined to meet the stringent requirements also defined by the Transmission System Code to conduct “routine verification [that] shall ensure with reasonable certainty that the protection systems respond correctly to fault conditions.” Planned Maintenance ensures that Hydro One’s assets are functioning properly by completing systematic inspection, detection, and correction of defects before failure or before they develop into major problems that will be more costly to correct later or become safety issues.

Mid-Life Overhaul/Refurbishment: is conducted to replace worn subcomponents of specific power system equipment and to increase its efficiency and reliability. The primary goal of this type of maintenance is to achieve the design life of the equipment in question and thereby defer capital expenditures. Major maintenance of this type must be both technically and economically feasible before being executed. Mid-life overhaul is primarily carried out on station assets such as transformers and breakers.

Unplanned Corrective Maintenance: includes unplanned corrective maintenance as well as response to emergency situations. This type of maintenance results from all unscheduled, non-
programmed maintenance caused by unforeseen problems and/or equipment failure. Corrective
maintenance is required to address the risk of harm and/or damage to any or all of employee
safety, public safety, system reliability or environment. Unplanned corrective also includes work
that was discovered during the course of planned maintenance activities where resolution should
not be deferred until a future scheduled maintenance activity.

2.2 SUSTAINMENT – CAPITAL WORK

The following are the categories of Capital work that are typically defined and executed at Hydro
One:

**Planned Replacement:** Hydro One mitigates system risk by replacing assets that have been
identified to be at end of life (EOL). End of Life is defined by the likelihood of failure and
where the failure of the asset would cause unacceptable negative consequences. Replacement is
chosen for assets when there is no technically or economically feasible maintenance option such
as increased planned maintenance, refurbishment of the asset, or a system reconfiguration option
that may eliminate the need for the asset in question. Replacement can take the form of
individual components, e.g., wood poles, insulators, or complete systems such as transformers
with bus work and protections.

**Emergency Equipment Spare Purchases:** Hydro One maintains a pool of spare equipment for
specific assets as part of the asset management strategy. Capital funding is used to purchase
spare transformers and circuit breakers, to provide spares over a group of assets that minimizes
capital investments while maintaining a sufficient reliability level. The determination of optimal
level of spares for specific assets is determined through statistical methods based on the
historical failure rate of the assets, the procurement time of the asset and the time to install the
asset. The final number of spares purchased is adjusted by considering the actual condition of
the assets to account for any expected change in the rate of failure.
Demand Driven Capital Replacement: In certain program areas Hydro One maintains capital funding in reserve to fund unforeseen equipment failures. Forecasts for the funding are set to historical spending levels unless trending or specific situations would indicate that a change is warranted.

3.0 SUSTAINING CAPITAL AND OM&A PROGRAMS

The assets under management are divided amongst three asset categories: Stations, Protection & Control (P&C), Telecom and Metering, and Lines. It should be noted that in Exhibit C1, Tab 2, Schedule 3 and Exhibit D1, Tab 3, Protection & Control and Telecom are presented as a subset of Stations, as the majority of these facilities are located within the transmission stations. The OM&A and Capital programs are linked by specific assets. The dominant linkages amongst the assets and their related Capital and OM&A programs are shown in the following tables.
# Table 1

## Stations Capital and OM&A Asset Linkages

<table>
<thead>
<tr>
<th>Capital Category</th>
<th>OM&amp;A Category</th>
<th>Assets</th>
</tr>
</thead>
</table>
| Station Environment | • Land Assessment and Remediation  
                           • Environmental Management | • Station Properties as related to LAR  
                                                                                  • Oil Containment Systems  
                                                                                  • Transformer Gasket Systems |
| Circuit Breakers |                | • Oil Circuit Breakers  
                           • SF6 Circuit Breakers  
                           • Metalclad Breakers  
                           • Vacuum Breakers |
| Station Re-investment | Power Equipment Maintenance | Can include all station equipment, with a focus on  
                                                                                  • Gas Insulated Switchgear  
                                                                                  • Air Blast Circuit Breakers  
                                                                                  • Boilers and Pressure Vessels  
                                                                                  • Metalclad Switchgear |
| Power Transformers |                | Transformers |
| Other Power Equipment |                | • Transmission Switches  
                                                                                  • High Voltage Instrument Transformers  
                                                                                  • Station Insulators  
                                                                                  • Station Cables and Potheads  
                                                                                  • Capacitor Banks  
                                                                                  • Station Buses  
                                                                                  • Station Surge Protection  
                                                                                  • Station Structures |
| Ancillary Systems | Ancillary Systems Maintenance | • High Pressure Air Systems  
                                                                                  • Batteries and Chargers  
                                                                                  • Station Grounding Systems  
                                                                                  • AC/DC Service Equipment  
                                                                                  • Oil and Fuel Handling Systems |
| Transmission Site Facilities and Infrastructure | Site Infrastructure Maintenance | • Station Properties  
                                                                                  • Station Buildings  
                                                                                  • Fences  
                                                                                  • Drainage and Geotechnical  
                                                                                  • Fire and Security Systems  
                                                                                  • Heating, Ventilation and Air Condition |
Table 2

P&C, Telecom and Metering Capital and OM&A Asset Linkages

<table>
<thead>
<tr>
<th>Capital Category</th>
<th>OM&amp;A Category</th>
<th>Asset</th>
</tr>
</thead>
</table>
| Protection, Control and Metering | Protection, Control, Monitoring and Metering Equipment Maintenance | • Revenue Metering  
• Protection & Control and System Monitoring                        |
| NERC Cyber Security             | Cyber Security                                      | All NERC and NPCC regulated Critical Cyber Assets and vulnerabilities |
| Auxiliary Telecommunication     | Telecommunications                                 | • Power Line System  
• Microwave Radio Systems  
• Fibre Optic Cables  
• Metallic Cable  
• Site Entrance Protection Systems  
• Teleprotection Tone Equipment |
| Equipment                       |                                                    |                                                                      |

Table 3

Lines Capital and OM&A Asset Linkages

<table>
<thead>
<tr>
<th>Capital Category</th>
<th>OM&amp;A Category</th>
<th>Asset</th>
</tr>
</thead>
</table>
| Overhead Lines Refurbishment and Component Replacement | Overhead Lines Programs | • Phase Conductor  
• Wood Pole Structures  
• Line Steel Structures  
• Shieldwire and Hardware  
• Line Insulators and Hardware |
| Transmission Lines Re-investment | Underground Cable Programs         | • Underground Cables and Potheads  
• Pumping Stations                                                                 |
| Underground Lines Cables Refurbishment and Replacement |                                    |                                                                      |

The spending between capital and maintenance programs is linked to some degree for sustaining investment. Reductions in one specific area will impact other spending areas. If an area of investment was reduced over the planning period, it would compromise long-term costs, reliability and customer satisfaction among other business values. The following tables summarize some of the impacts of reducing specific capital and maintenance areas in Stations and Protection & Control, Telecom and Lines.
### Table 4A - Capital

**Capital and OM&A Spending Linkages**

<table>
<thead>
<tr>
<th>Investment Area</th>
<th>Spending Impacts of Reductions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circuit Breaker – Capital</td>
<td>• Power Equipment – OM&amp;A: Increase in corrective maintenance because of equipment failures and possible increase in refurbishment to maintain reliability. Potential increases in preventive maintenance to maintain reliability levels.</td>
</tr>
<tr>
<td></td>
<td>• Environmental – OM&amp;A: Potential increase in corrective maintenance because of equipment failures resulting in spilled oil.</td>
</tr>
<tr>
<td></td>
<td>• Power Transformer – Capital: Breaker failures during fault clearing operations expose transformers to longer fault durations. This advances EOL of power transformers.</td>
</tr>
<tr>
<td>Station Reinvestment – Capital</td>
<td>• Power Equipment – OM&amp;A: Increase in corrective maintenance because of equipment failures and possible increase in refurbishment to maintain reliability. Potential increases in preventive maintenance to maintain reliability levels.</td>
</tr>
<tr>
<td></td>
<td>• Environmental – OM&amp;A: Potential increase in corrective maintenance because of equipment failures spilling oil.</td>
</tr>
<tr>
<td></td>
<td>• Power Transformer – Capital: Breaker failures during fault clearing operations expose transformers to longer fault durations. This advances EOL</td>
</tr>
<tr>
<td></td>
<td>• Other Power Equipment and Ancillary – Capital: If this equipment is not replaced through integrated projects there will be long term pressures to replace EOL assets individually, as opposed to more efficient replacement through bundled investments</td>
</tr>
<tr>
<td>Power Transformer – Capital</td>
<td>• Power Equipment – OM&amp;A: Increase in corrective maintenance on transformers and possible increase in refurbishment to maintain reliability levels.</td>
</tr>
<tr>
<td></td>
<td>• Environmental – OM&amp;A: Potential increase in corrective maintenance because of equipment failures spilling oil.</td>
</tr>
<tr>
<td>Other Power Equipment – Capital</td>
<td>• Power Equipment – OM&amp;A: Increase in corrective maintenance because of equipment failures. Potential increases in preventive maintenance to maintain reliability levels.</td>
</tr>
<tr>
<td>Investment Area</td>
<td>Spending Impacts of Reductions</td>
</tr>
<tr>
<td>---------------------------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Ancillary – Capital</td>
<td>• Power Equipment – OM&amp;A: Increase in corrective maintenance because of related equipment failures (especially high pressure air systems which supply air blast circuit breakers). Potential increases in preventive maintenance to maintain reliability levels.</td>
</tr>
<tr>
<td></td>
<td>• Ancillary – OM&amp;A: Increase in corrective maintenance because of equipment failures. Potential increases in preventive maintenance to maintain reliability levels.</td>
</tr>
<tr>
<td></td>
<td>• Circuit Breaker – Capital: If air systems are not maintained moisture could have serious impacts on the reliability of the air blast circuit breakers, leading to potential failures.</td>
</tr>
<tr>
<td>Station Environment - Capital</td>
<td>• Environmental – OM&amp;A: Increase in corrective maintenance because of clean-up and stop gap measures required with ineffective spill containment systems.</td>
</tr>
<tr>
<td>P &amp;C, Telecom, Metering - Capital</td>
<td>• P&amp;C – OM&amp;A: Increase in corrective to maintain stability. Increase in re-verification to maintain reliability.</td>
</tr>
<tr>
<td></td>
<td>• Telecom – OM&amp;A: Increase in corrective to respond to failures and make repairs.</td>
</tr>
<tr>
<td></td>
<td>• Power Equipment - OM&amp;A: Increase in corrective as a result of miss operations causing equipment damage.</td>
</tr>
<tr>
<td></td>
<td>• Power Transformer – Capital: Defective protection schemes can result in transformers being exposed to faults for a longer period during clearing operations. This advances EOL of power transformers.</td>
</tr>
<tr>
<td>Site Infrastructure &amp; Security - Capital</td>
<td>• P &amp;C, Telecom, Metering – Capital and OM&amp;A: Potential increases in P&amp;C corrective maintenance and required capital replacement because of site drainage issues or air conditioning system failures, leaking roofs.</td>
</tr>
<tr>
<td></td>
<td>• Circuit Breakers and Transformers Capital and OM&amp;A: Potential increases due to failures of fire protection systems.</td>
</tr>
<tr>
<td>Overhead Lines - Capital</td>
<td>• Lines – OM&amp;A and Capital: Increase in corrective OM&amp;A and Capital to manage an increase in defects and failures if EOL replacements are reduced. Increase in preventative maintenance for stop gap measures.</td>
</tr>
<tr>
<td>Underground Cables - Capital</td>
<td>• U/G Cables – OM&amp;A and Capital: Increase in corrective OM&amp;A and Capital to manage an increase in defects and failures if EOL replacements are reduced. Increase in preventative maintenance for stop gap measures and added diagnostics.</td>
</tr>
</tbody>
</table>
### Table 4B – OM&A

Capital and OM&A Spending Linkages

<table>
<thead>
<tr>
<th>Investment Area</th>
<th>Spending Impacts of Reductions</th>
</tr>
</thead>
<tbody>
<tr>
<td>LAR – OM&amp;A</td>
<td>• Environmental and Facilities: Increase cost to manage on site containment.</td>
</tr>
</tbody>
</table>
| Environmental – OM&A             | • Power Transformer – Capital: There is the potential for increased pressure to increase power transformer replacements if oil leaks are not repaired.  
                                 | • Environmental – OMA – corrective would increase with reduced oil leak reduction and containment pit maintenance.                                                                                                         |
                                 | • Power Transformer and Breakers – Capital: If mid-life refurbishments and preventative maintenance programs were cut, transformer performance and condition would degrade, resulting in increased pressures to replace EOL power transformers. |
| Ancillary – OM&A                 | • Power Equipment – OM&A: Increase in corrective maintenance because of related equipment failures (especially high pressure air systems which supply air blast circuit breakers).  
                                 | • Ancillary – OM&A: Increase in corrective maintenance because of equipment failures.  
                                 | • Circuit Breaker – Capital: If air systems are not maintained moisture could have serious impacts on the air blast circuit breakers.  
                                 | • Ancillary – Capital: Increase in replacement in grounding systems, station service and batteries and chargers are possible because of a lack of Ancillary OM&A.                                      |
                                 | • Increased cost of outages affecting capital and OM&A programs due to correctives not addressed  
                                 | • Increased cost in demand corrective                                                                                                                                                                                        |
| Site Infrastructure – OM&A       | • Site Infrastructure – OM&A: Increase in corrective maintenance because of fire protection systems and Heating, Ventilation and Air-Conditioning systems.  
                                 | • P &C, Telecom, Metering – Capital and OM&A: Potential increases in P&C because of site drainage issues or air conditioning system failures.  
<pre><code>                             | • Circuit Breakers and Transformers Capital and OM&amp;A: Potential increases due to failures of fire protection systems.                                                                                       |
</code></pre>
<table>
<thead>
<tr>
<th>Investment Area</th>
<th>Spending Impacts of Reductions</th>
</tr>
</thead>
</table>

4.0 ASSET DESCRIPTIONS

Appendix A - Asset Descriptions, Demographics and Performance, provides descriptions for major transmission assets that are managed by Hydro One Transmission and require Sustaining Investments.
Appendix A:
Hydro One Transmission Assets

Asset Descriptions
Asset Demographics
Asset Performance
Hydro One Transmission Assets

1.0 Introduction

This report provides descriptions, demographic data and performance data for major transmission assets that are affected by Hydro One Sustaining investments. This report is intended to provide context for the investment programs described in Exhibit C1, Tab 2, Schedule 2 - Sustaining Operating, Maintenance and Administration (OMA) and in Exhibit D1, Tab 3, Schedule 2 - Sustaining Capital.

This report describes assets that are in the following categories:
- Station – Power System Equipment
- Stations – Protection and Control
- Lines

2.0 Station – Power System Equipment Descriptions

This section provides descriptions of major power system assets that are found at Hydro One Stations excluding Protection and Control assets.

2.1 Circuit Breakers - General

A circuit breaker is a mechanical switching device that is capable of making, carrying and interrupting electrical current under normal and abnormal circuit conditions. Abnormal conditions occur during a short circuit such as a lightning strike or conductor contact to ground. During these conditions, very high electrical currents are generated that greatly exceed the normal operating levels. A circuit breaker is used to break the electrical circuit and interrupt the current to minimize the effect of the high currents on the rest of the system.

Transmission system buses are typically configured to provide either a breaker and a half or a breaker and one third arrangement, providing a degree of redundancy. Medium voltage breakers are typically configured in a radial feeder arrangement but a degree of redundancy is provided by the feeder tie switch normally used at DESN stations. Breakers may be constituted either as a 3-pole unit, with the operating mechanisms of all three phases contained in a single tank; or 3 single-pole units, with each pole contained in its own tank, and linked together to operate simultaneously. General Purpose circuit breakers are intended to operate infrequently. Definite purpose circuit breakers are designed to operate frequently, for applications such as capacitor and reactor switching.

Hydro One currently manages approximately 4450 in-service circuit breakers. These breakers are separated into different classes based on specifications, voltage and manufacturer. The insulating medium determines the type of circuit breaker e.g. oil, air, vacuum or sulphur hexafluoride (SF₆) gas. Circuit breaker technology has evolved over time with the use of these insulating media i.e.
oil was developed first, then high pressure air blast circuit breakers (ABCBs), and now vacuum and SF₆. Air blast technology replaced oil to cope with the higher power system voltages (the physical space and oil volume requirements at these higher voltages are enormous), but it also eliminated the environmental and fire hazards associated with oil. SF₆ was later introduced to replace air because it is a very stable, chemically inert gas whose insulating properties are 2-3 times greater than air making it ideal for use at high system voltages.

Circuit breakers are intended to operate infrequently; however, on the occurrence of an electrical fault, the breaker must operate reliably and very quickly to interrupt the fault without damage to itself and with a minimum disturbance to the remainder of the circuit and the electrical system. Typically, they are capable of interrupting currents in as short a time as 32 milliseconds.

Hydro One currently employs a variety of breaker technologies and ratings at non-GIS substations. The majority of the oil and air blast, (obsolete technology) circuit breakers are over 40 years of age with some approaching 60 years since their original manufacture.

While SF₆ and Air Blast designs are applied across the complete medium and high voltage rating spectrum, oil circuit breakers are not applied beyond the 230kV level. Magnetic Air and Vacuum technologies are restricted to the medium voltage categories below 50kV and together with their medium voltage SF₆ counterparts are applied, in outdoor air insulated stations (AIS) and in indoor metalclad switchgear arrangements. The majority of SF₆ breakers and essentially all oil breakers within the Hydro One system are of the dead tank type. Typically the dead tank design is the most cost effective since it can incorporate all necessary current transformers, thereby reducing space and installation requirements. Due to physical similarities, many oil circuit breakers that have reached the end of their service lives are being replaced with dead tank SF₆ breakers.

In dead tank design, the interrupter chamber is accommodated in a grounded metal housing. SF₆ gas serves as an insulator between the live contact assembly and the surrounding metal housing. High voltage terminals are connected to the interrupter chamber through outdoor bushings. Bushings normally incorporate bushing CTs thus avoiding the need for free standing HV current transformers. Dead tank circuit breakers employing both the old double-pressure technology and the newer, and simpler, single pressure technology have been applied on the Hydro One system. The dead tank design has been widely used at the medium voltage levels and at the lower transmission voltage applications (115 and 230 kV, but has also been developed for application at the highest voltage levels). Several have been successfully applied on the Hydro One 500 kV system.

In the live tank design, the interrupter chamber, which may be of the porcelain or composite material, is supported and insulated from ground, by vertical insulating support columns. Thus the chamber or tank is operated at system voltage. Voltage level determines the dimensions of the support and the tank insulators.

A very small portion of Hydro One HV SF₆ breakers and all HV air blast breakers are of the live tank type and are normally associated with separate, free standing, current transformers.
2.1.1 Oil Circuit Breakers

Oil Circuit Breakers (OCBs) are installed on the power system to interrupt load and fault currents and to de-energize power carrying assets to facilitate maintenance. An OCB consists of either one or three steel tanks filled with insulating oil in which pairs of operating contacts are immersed. These contacts are enclosed in an arc control “pot” which enables rapid extinction of the arc during an interruption.

A typical high voltage OCB used by Hydro One is shown in Figure 1.

![Three Tank Oil Circuit Breaker](image)

**Figure 1 - Three Tank Oil Circuit Breaker**

**Method of Arc Extinction**

The method of arc extinction employed in OCBs is high-resistance interruption. The arc is controlled in such a way that its resistance is caused to increase rapidly, thus reducing the current until it falls to a value that is insufficient to maintain the gas ionization process.

**Main Components**

The main components of bulk OCBs are listed below, along with a short description of their use and purpose:
Control Cabinet and Operating Mechanism

The cabinet contains control relays, wiring, heaters, current transformer terminals, and the breaker-operating mechanism.

Tank

The tank contains the oil, the interrupter units, support mechanisms and operating rods and linkages to ensure simultaneous operation of each interrupting unit. Current transformers for protective relaying and metering purposes are also installed inside the tank where the incoming high voltage connections are located.

Exterior of the Tank

Oil-filled bushings are mounted on the tank for electrical clearance and the connection of the breaker into the power system.

2.1.2 SF6 Circuit Breakers

The first SF6 circuit breaker was developed in the late 1960s and was a double-pressure design (low pressure tank and high pressure reservoir), based on the air blast technology. The double pressure design is very complex both electrically and mechanically and was quickly rendered obsolete by the single pressure design developed in the mid 1970s. The simpler, single pressure SF6 insulated circuit breaker, despite some early design reliability issues, has now become the technology of choice for transmission class circuit breakers. No compressor or other complex auxiliary equipment is required, since the gas for arc interruption is compressed in a puffer action by a piston during the opening operation. Recent improvements in the single pressure design, by the use of self blast or other related techniques to assist the interrupting process, has resulted in still simpler and more reliable breakers using spring charged or hydraulic-spring operating mechanisms.
A typical HV SF₆ circuit breaker used by Hydro One is shown in Figure 2.

Hydro One introduced SF₆ equipment to the system at a very early stage in its evolution during the 1970s. As a result of this, they did suffer from significantly raised failure rate due to prototype problems. In addition, the degradation in performance was accelerated by the more onerous operating and special purpose switching conditions encountered on the Hydro One system.

A large proportion (about 30%) of the SF₆ breaker population is applied for the most onerous, special purpose duties, such as reactor and capacitor bank switching, some involving several hundred operations per year thus accelerating the mechanical and electrical wear out of the breaker. The complex control and operating mechanisms installed in almost all of these early vintage breakers resulted in increased operating problems and significant maintenance and refurbishment expenditures. Most of these very poor performing breakers have reached or surpassed their mechanical design life of 2000 switching operations.

Heaters are required on many of these breakers to prevent liquefaction of the SF₆ gas at the low temperatures prevailing in Ontario. Heaters and control equipment, contactors, thermostats, and wiring degrade at an accelerated rate under these extreme conditions.
Gas seals leak at an increased level at low temperature putting increased pressure associated apparatus. Generally, earlier models have more problems than later ones, since modern equipment has improved seal and valve designs.

2.1.3 Air Blast Circuit Breakers (ABCBs)

High voltage (115kV, 230kV and 500kV) ABCBs are typically applied in “breaker and a half” and “breaker and a third” schemes which provide improved reliability by redundancy. Low voltage (less than 50kV) ABCBs are connected radically to supply load to individual feeders. A typical HV ABCB used by Hydro One is shown in Figure 3 below.

![230 kV Air Blast Circuit Breaker](image)

**Figure 3: 230 kV Air Blast Circuit Breaker**

ABCBs are complicated in design and incorporate a large number of moving parts, valves and seals. They also require a high-pressure compressed air (HPA) supply. Centralized HPA systems are installed at all locations that have a population of ABCBs. The HPA systems are usually comprised of multi-stage compressors, chemical or heated dryers, numerous air storage receivers, extensive piping and valving arrangements, and controls. The design, condition and successful operation of the central air systems have a direct bearing on the capability of the ABCB to properly perform its designed function. Excessive moisture in the air could lead to explosive failure of circuit breakers. Conversely if ABCBs experience excessive leakage it will result in excessive run times for compressors and dryers and increased maintenance and refurbishment costs related to the air system.
The utility industry has identified degradation of gaskets, seals, and valves as the critical long-term issues related to EOL of ABCBs. Experience has shown that gasket and seal deterioration is time-related with major performance problems being experienced when gaskets and seals are 20-25 years old. To deal with these in the past Hydro One has undertaken a major rebuild of each ABCB after approximately 20-25 years of service. The last rebuild program was completed in 1995. OEM facilities and resources associated with the rebuild program are no longer available and major rebuilds are no longer feasible.

2.1.4 Gas Insulated Switchgear (GIS)

Gas insulated switchgear (GIS) is an assembly of switchgear in which all of the major components, except for the entrance bushings, are housed within a grounded metal enclosure containing pressurized sulphur hexafluoride (SF₆) gas. The GIS is compartmentalized in such a manner as to readily facilitate maintenance of individual components with minimum disruption to adjacent components and also to minimize gas losses in the event of an uncontrolled rupture of an enclosure. Many compartments are fitted with pressure relief devices which are designed to relieve excess pressure in the event of an internal fault and so prevent enclosure rupture. GIS is very compact compared to AIS and is applied at all the voltage levels, LV, HV and EHV on the Hydro One system. Gas insulated switchgear is an attractive alternative to an outdoor air insulated substation (AIS), particularly where space constraints and protection from harsh environmental conditions are a consideration.

All are indoor installations. Some are in heated buildings, while others are in unheated buildings. Several stations have extensive outdoor runs of bus between the GIS and associated overhead line terminations and transformers. As shown in Figure 4 and 5, the GIS incorporate some or all of the following components:
- Circuit breakers
- Switches - disconnect and ground switches
- Bus

Other equipment including: SF₆/air entrance bushings; SF₆/cable terminations, instrument transformers, current and voltage transformers, surge arresters and protection, control, and monitoring equipment.
Figure 4: 500 kV GIS Indoor Equipment

Figure 5: 500 kV GIS Outdoor Exit Bus Equipment
Metal enclosed, concentric, SF₆ insulated buses are used to interconnect other live GIS components such as circuit breakers, disconnect switches and interfaces with overhead lines, cables and transformers. Within the bus, aluminum conductors are supported on epoxy resin insulators. About 30% of the failures which have occurred since the late 1970s have been on these epoxy resin insulators. The current failure rate is considerably lower and Hydro One has developed diagnostics and monitoring procedures to detect potential failures.

2.1.5 Metalclad Switchgear

Metalclad switchgear is an assembly of switchgear in which all of the major components are housed within a grounded metal enclosure. Construction for this type of equipment utilizes insulated bus and compartmentalization. The switchgear is compartmentalized in such a manner that all major power components are completely segregated from each other by a grounded metallic enclosure. Metalclad switchgear is an attractive alternative to an outdoor air insulated substation (AIS), particularly where space constraints and protection from harsh environmental conditions are a consideration.

All Hydro One metalclads are indoor installations. Some are in heated buildings, while others are in unheated buildings. The switchgear incorporates some or all of the following components:

- Circuit breakers
- Switches
- Bus
- Other equipment including: entrance bushings; cable terminations, instrument transformers, current and voltage transformers, surge arresters and protection, control, and monitoring equipment

The majority of Hydro One’s voltage metalclad switchgear installations consist typically of an indoor line-up of 10 to 14 cells as illustrated in Figure 6.
Figure 6: Typical Hydro One Metalclad Switchgear

Figure 7 shows a typical circuit breaker withdrawn from the Metalclad Switchgear.

Figure 7: Circuit Breaker Withdrawn from Breaker Compartment

Figure 8 shows a typical control cabinet that is located within the Metalclad Switchgear.
There are a variety of circumstances that result in internal arcs in metalclad switchgear. Often times this failure occurs when the breaker fails during routine switching or when clearing a through fault. A dangerous situation also exists when a breaker fails to properly open prior to racking-in or racking-out. Other causes of internal failure are due to partial discharge activity that weakens the insulation over time. Overvoltage surges on equipment with weakened insulation can result in internal failure. Operational mishaps can occur to cause internal faults such as mis-operation, or tools, grounds or other equipment being left in a cubicle during maintenance checks.

Although the probability of an arcing fault inside MV metal-clad switchgear is low, the cost in terms of personnel safety and equipment damage is high when an arcing fault occurs. Since the early 1980’s some Canadian utilities including Hydro One have purchased arc resistant medium voltage switchgear. Hydro One still retains a significant population of older switchgear on the system which was retrofitted with minimum arc resistance provision but does not meet current standards for arc resistance. The majority of the circuit breakers in these switchgears are either obsolete air magnetic or SF6 designs. All modern switchgear incorporates vacuum circuit breakers for economic reasons and because of environmental concerns with SF6.

Arc resistant switchgear is characterized by some special design features necessary to achieve the required ratings. The switchgear enclosure construction must be designed to contain the internal arc pressure and direct it to the pressure relief flaps or exhaust chambers designed to
safely vent the arc products. Movable vent flaps are designed to open due to the arc fault pressure, increasing the volume containing the arc products. Any ventilation designs with flaps that are open under normal operating conditions must close when an arc fault occurs.

Racking and operation of all equipment such as circuit breakers, switches and instrument transformers must be through closed doors.

The integrity of the low voltage control and protective device circuitry is critical. Instrument compartments, which contain the protective relays, meters, devices, and wiring, should be separate reinforced modules. The interior surfaces of the instrument compartment are considered as part of the arc resistant enclosure boundary and must satisfy the same criteria as the switchgear enclosure during type testing. This protects personnel who may be working in or near the compartment as well as the P&C devices themselves, and control wiring which may otherwise be destroyed as a result of the arc fault. This is extremely important as the protective scheme is being relied on to limit the duration of the arc fault.

Sufficient clearance must be provided above the switchgear to allow the arc products to be dispersed properly and not to be reflected back into the area that could be occupied by personnel. Additionally sufficient clearance from the pressure relief flaps should be provided for any control cable trays, medium voltage insulated cables, buses or other electrical equipment located above the switchgear. Where appropriate clearances are not possible due to the design of the enclosure/building, an exhaust plenum can be provided to safely vent the gases externally to an area that is not accessible to personnel. The plenum design must be tested to verify satisfactory performance under internal arc fault conditions.

Studies in the past indicate that certain existing indoor metalclads of simple design (i.e. few compartments per cell) can be retrofitted with limited arc resistant functionality. This has been implemented in all of the pre-1985 metalclads which comprise about 50% of the Hydro One metalclad population. However this limited arc resistance functionality does not generally comply with Hydro One current Safety and Arc Flash requirements. In addition at least 10 of these installations require the cell door to be opened and the circuit breaker to be manually levered into place, which represents a high risk for personnel safety.
2.2 Transmission - Power Transformers

Transformers are static devices whose primary purpose is to either step-up or step-down voltage. Transformers change AC electric energy at one-voltage level to AC electric energy at another level via induction of a magnetic field. A transformer consists of two or more coils of wire wrapped around a common ferromagnetic core. One of the transformer windings is connected to the source of the AC electric power called the primary or input winding, and the second winding connected to the load is called the secondary or output winding. The main connection between the windings is the common magnetic flux present within the transformer’s core.

2.2.1 Power Transformers

The purpose of a power transformer is to convert large amounts of electrical power from one voltage level to another. These devices vary in size from that of a small car to the size of a small house. There are two general classifications of power transformers: transmission transformers and distribution transformers. Transmission transformers connect transmission lines of various voltages to one another. Transmission power transformers are almost always fitted with the under load tap changer (ULTC) mechanism. A picture of a typical Hydro One’s transmission station power transformer is shown in Figure 9.

![Figure 9: Typical Transmission Station Power Transformer](image)
Transformers are made up of the following primary components. Some components are optional, as indicated below, depending on the transformer application:

- Primary and secondary windings each installed on a laminated iron core
- Some also have tertiary windings
- Internal insulating mediums
- Main tank
- Bushings
- Cooling system, including radiators, fans and pumps (Optional)
- Off circuit tap changer De-energized tap changer (Optional)
- ULTC LTC (Optional)
- Current and potential transformers
- Mechanism cabinets.

Primary and Secondary Windings

The primary and secondary windings of a transformer are each installed on a laminated iron core and serve as the coils that react with the magnetic flux of the transformer core. When the magnetic circuit takes the form of single ring encircled by two or more groups of primary and secondary windings distributed around the periphery of ring, the transformer is termed a core type transformer. Core type transformers represent close to 100% of the power transformers built today and are widely applied because the design is technically reliable and it is cost effective. Figure 10 shows the construction of a single-phase core type transformer.

![Core Type Transformer](image)

**Figure 10: Core Type Transformer**

When the primary and secondary windings take the form of a common ring that is encircled by two or more rings of magnetic material distributed around its periphery, the transformer is termed a shell type transformer. Figure 11 shows the construction of a shell type transformer.
Shell type transformers are an older, more complex, transformer design that are more costly to build, but normally exhibit a superior short circuit withstand capability. Westinghouse transformers built prior to 1965 are of this design. The winding materials are made of both copper and aluminum, available in sheet (foil) and rectangular conductor configurations. For transposed cable applications only copper is used.
Internal Insulating Mediums

The internal insulating mediums serve as the necessary electric insulation and in the case of mineral oil as a coolant. Low cost, high dielectric strength, excellent heat-transfer characteristics, and ability to recover after dielectric overstress make mineral oil the most widely used transformer insulating material. The oil is reinforced with solid insulation in various ways. The major insulation usually includes barriers of wood-based paperboard (pressboard), the barriers usually alternating with oil spaces. Because the dielectric strength of oil is approximately half that of the pressboard, the dielectric stress in the oil is higher than that in the pressboard, and the design structure is usually limited by the stress in the oil. The insulation on the conductors of the winding may be enamel or wrapped insulating paper tape which is either cellulose or nylon based. The use of insulation directly on the conductor actually inhibits the formation of potentially harmful electrical breakdown streamers in the oil, thereby increasing the strength of the structure. Heavy paper wrapping is also usually used on the leads which connect the windings to the external terminals of the transformer.

Main Tank

The main tank is used to hold the active components of the transformer in an oil volume that maintains a sealed environment through the normal variations of temperature and pressure. Typically the main tank is designed to withstand a full vacuum for initial and subsequent oil fillings and is able to sustain a positive pressure. The main tank also supports the internal and external components of the transformer. Main tank designs can be classified into 2 types those being conservator and sealed types.

Hydro One typically uses conservator types which have an externally mounted tank that is designed to hold up to 12% of the main tank’s volume. As the transformer oil expands and contracts due to system loading and ambient temperature changes, the corresponding oil volume change must be accommodated. This tank is used to provide a holding mechanism for the expansion and contraction of the main tank’s oil over these temperature variations. This design reduces oxygen and moisture contamination since normally only a small portion of oil is exchanged between the main tank and the conservator and a minimum volume of the oil is exposed to the air. However, eventually oil in the conservator is exchanged with oil in the main tank and oxygen and other contaminates gain access to the insulation.

Bushings

Bushings are used to facilitate the ingress of the electric power circuits in an insulated, sealed (oil-tight and weather-tight) manner. A bushing is typically composed of an outer porcelain body mounted on metallic flange. The phase leads are either independent paper insulated, or are an integral part of the bushing. At the higher voltage levels, additional insulation is incorporated in the form of mineral oil and wound paper stress cone installed within the porcelain body.

Power transformers bushings can be roughly divided into “bulk” and “condenser” types and are used on the primary and secondary winding connections including the neutral points.
Cooling System (Radiators, Fans, and Pumps)

Cooling systems provide a means for the removal of internal heat generated through the transformer losses. The system is necessary to prevent the build up of excessive internal temperatures that would shorten the life of the insulation systems. Transformer cooling system ratings are typically expressed as:

- Self-cooled (radiators) with designation as ONAN (oil natural, air natural).
- Forced cooling first stage (fans) with designation as ONAF (oil natural, air forced).
- Forced cooling second stage (fans and pumps) with designation as OFAF (oil forced, air forced).
- Forced cooling first or second stage (fans and pumps) with designation as ODAF (oil directed, air forced).

The utilization of a number of cooling stages allows for an increase in load carrying capability. Loss of any stage or cooling element may result in a forced de-rating of the transformer.

Off Circuit Tap Changer (OCTC)

An OCTC is a device by which the power transformer turns ratio can be altered over small range to effect changes in output voltage as required. The change in ratio is typically accomplished in the high voltage winding by dividing the physical winding into two halves in combination with the use of several selectable winding taps. An OCTC application typically allows for an adjustment of 5% above nominal and 5% below nominal voltage in 2½ % steps. An OCTC must only be operated with the transformer off potential.

Underload Tap Changer (ULTC)

ULTCs allow for automatic voltage changes while adjusting to varying load conditions on line. An ULTC is of particular importance to those situations where frequent voltage regulation is required because of the characteristic of the load. ULTCs are complex in their design. As a control mechanism, they consist of moving mechanical parts, a drive motor, linkages and voltage regulation sensing equipment. The ULTC incorporates tapped connections to the main windings that can be selected automatically, through a series of main and arcing contacts, to adjust the secondary voltage of the transformer without interrupting the load.

Current Transformers

Current transformers (CTs) sample the current in a line and reduce it to a safe and measurable level. CTs consist of a secondary winding wrapped around a ferromagnetic ring (transformer bushing’s primarily lead), with the single primary line running through the centre of the ring. The ferromagnetic ring holds and concentrates a small sample of the flux from the primarily line. That flux then induces a proportional voltage and current in the secondary winding.
Mechanism Cabinets

The mechanism cabinet is an externally mounted box that supports voltage and current control relay, secondary control circuits, and in some cases the tap changer motor and position indicators.

2.2.2 Autotransformers

An autotransformer is a special case of power transformers, which are used primarily to transform voltages and currents between transmission system voltage levels (between 500 kV and 230 kV and between 230 kV and 115 kV in Hydro One’s system). In the case of an autotransformer, there is no electrical isolation between the primary and secondary windings, as part of the winding is common and shared by the primary and secondary. This is a cost-effective solution in applications where the primary to secondary voltage ratios are less than about 2:1 and where the common connection is acceptable. Autotransformers can be fitted with the ULTC mechanism as well.

Because there is no electrical isolation between the primary and secondary windings in an autotransformer, no phase shift occurs between primary and secondary voltages. Most conventional two winding three phase transformers are built with a 30-degree phase shift inherent in the design. Therefore the application of autotransformers has to be carefully planned to ensure that the appropriate phase relationship exists in the system. In the Hydro One system autotransformers are used with primary voltages at 500 kV, 230 kV and 115 kV. However, those with a primary voltage of 115 kV are rarely needed and are only used where special phasing is required.

2.2.3 Phase Shifting Transformers

In an alternating current system, the voltage varies from maximum to minimum 60 times per second, or 60 Hertz. In two systems, both operating at 60 Hertz, there can be a shift between when the reference phase of one system peaks and the other system peaks. This would cause an electrical disturbance if both systems were interconnected. Real power flow in transmission systems is controlled through control of phase differences, therefore phase shifting transformers are employed in selected locations to optimize power flows in the system. Phase shifting transformers are very complex to design and manufacturer and often require a two-tank design.
2.2.4 Shunt Reactors

While strictly speaking, shunt reactors are not transformers, they are similar in construction and considered by Hydro One in the same asset class. A shunt reactor is basically a single winding wound on an iron core and its construction, maintenance and testing is similar to a power transformer.

A transmission line has two main electrical properties characteristic of its design, resistance and reactance. Reactance can be either inductive or capacitive, one cancelling out the effect of the other. Both resistance and reactance contribute to transmission line losses, while resistance is fixed and cannot be changed, the inductive reactance can be cancelled by capacitive reactance or increased by adding additional inductive reactance.

The primary purpose of shunt reactors is to introduce reactance into a circuit. Shunt reactors are normally used to absorb reactive power for voltage control. Series reactors are devices normally used to increase the effective reactance on a circuit to limit fault current.

2.2.5 Regulator Transformers

Regulator transformers are transformers whose sole purpose is to provide voltage regulation through use of an internal tap changer. The nominal incoming and outgoing voltages are the same but the outgoing voltage can be varied slightly in 2.5% increment to satisfy the voltage requirements of connected customers.

2.2.6 Grounding Transformers

Grounding transformers are used to provide a neutral point for grounding an electrical system.

Electrical distribution systems can be configured as a grounded or ungrounded system. A grounded system has an electrical connection between source and the earth, whereas an ungrounded system has no intentional connection. Sometimes it is necessary to create a ground on an ungrounded system for safety or to aid in protective relaying applications. Smaller transformers similar in construction to power transformers are used in this application.

2.2.7 Station Service Transformers

The operation of the transmission station requires power for various services such as lighting, operation of fans, relay room heating and ventilation, power for battery chargers, etc. The most reliable source of such power is directly from the transmission or distribution lines. Small power transformers are used to provide this power supply.
2.3 HV/LV Switches

Disconnect switches are used to visually and electrically isolate equipment or line sections of the transmission system for purposes of maintenance, safety, and other operating requirements. Disconnect switches generally have no assigned or tested current interruption capabilities. However it is common practice within Hydro One as in other North American utilities to use them to interrupt small bus currents of a few amperes and transformer magnetizing currents of limited magnitude. Also included in this asset class are load interrupter switches which have limited load and fault interrupting capability. The interrupter mechanism normally contains a gas/vacuum, as the insulating medium and these switches also must be capable of providing visual confirmation of the open/close position. The switches currently in use on the Hydro One transmission system have been purchased from more than 10 different manufacturers over the past 60 years.

In general switches consist of a mechanically movable copper or aluminum conductor /blade, supported on insulators and mounted on a metal base. Rotation of one or more of the insulator stacks causes the current path to make or break the circuit, as required as shown in Figure 12. The operating or control mechanism may be a simple hook stick, manually gang operated, or motor operated. The latter is primarily used on transformer and line circuits, where protective relays may be used to operate the switch automatically as shown in Figure 13. Disconnect switches are relatively simple in design compared to circuit breakers because they are not required to interrupt large currents in most applications.

Kearney (type DHE) 138kV 1200A Disconnect Switch

Figure 12: Center Rotating Disconnect Switch
Disconnect switches may be mounted vertically, horizontally or inverted and various switch designs may be deployed depending on the station arrangement of facilities. These are described according to their operation or blade motion as shown in Table 1.

<table>
<thead>
<tr>
<th>Vertical Break</th>
<th>Blade contact rises out of the jaw contact-three insulator stacks are usually used</th>
</tr>
</thead>
<tbody>
<tr>
<td>Side Break</td>
<td>Blade contact parts to the side</td>
</tr>
<tr>
<td>Double Break, Centre Rotating</td>
<td>Contacts at each end of the blade part to opposite sides due to the rotation of the centre of the centre of three insulator stacks</td>
</tr>
<tr>
<td>Centre Break, Both Ends Rotating</td>
<td>Both jaw and tongue contacts move to the one side by rotation of both insulator stacks.</td>
</tr>
</tbody>
</table>

Table 1: Switch Operation Description

A load interrupter switch typically comprises of a motor operated, three phase, load carrying and interrupting device having a limited fault interrupting capability, mounted on support insulators and metal support structure. The interrupter may be either air or vacuum, or SF6 which is the dominant technology on the Hydro One system. It may, or may not, incorporate disconnect blades for isolating purposes. Typical load carrying and breaking capabilities are in the 600A to 2000A range and interrupter switches have been applied in the MV, HV and EHV rating
categories. Interrupters on the older designs were typically sealed for life and replaced rather than repaired upon failure. In some cases the OEM is no longer supplying or supporting the older design, thus driving the EOL decision process for certain applications. The more recent designs are very similar in design and operation to live tank SF6 circuit breakers. There are almost 300 load interrupter switches on the Hydro One system. Depending on the operating requirements, some switches are manually operated and others motor operated.

2.4 High Voltage Instrument Transformers (HVITs)

HVITs consist of voltage and current transformers that are independent, freestanding devices that are used in Hydro One’ transmission stations at voltages of 115 kV and above.

The application of control, protection (relaying) and metering functions to HV systems requires the use of sensitive measuring devices, which are typically incapable of withstanding the high currents and high voltages present on the Hydro One’ primary system. For this reason, the primary voltages and currents in typical HV systems must be accurately transformed to low values that are acceptable to the measuring devices. In HV systems special transformers called instrument transformers carry out this function.

There are two basic types of instrument transformers: voltage transformers (VTs) and current transformers (CTs).

VTs are devices for measurement of bus and line voltages that, on the primary side, are connected between the phase and neutral conductors of the HV system. The ratio of the primary to the secondary winding is typically chosen to provide a secondary voltage of 120 volts when the primary system voltage is at its nominal value. This secondary voltage is used for control, protection and metering devices and varies directly in proportion to the primary system voltage.

CTs are devices for measurement of line currents that are connected on the primary side in series with the phase conductors of the HV system. The ratio of the primary to the secondary winding is typically chosen to provide a secondary current of 5 Amps when the primary system current is at its nominal value. This secondary current is used for control, protection and metering devices and varies directly in proportion to the current in the primary system.

VTs and CTs in HV systems are usually oil insulated and enclosed in a high strength sealed porcelain insulator to withstand the applied voltage stresses. Presently, other types of current transformers are being supplied that use SF6 as the insulating medium instead of oil.

There are two different types of voltage transformers: inductive and capacitive as described below.

An inductive VT is wound in the similarly to a conventional power transformer: it uses inductive coupling to reduce the primary (high) voltage to a lower analogue voltage. Inductive VTs can be used at any voltage level, but they are only cost effective at lower voltages, typically below 115 kV. In the Hydro One’ system, inductive VTs are used primarily up to 44 kV.
The cost of inductive VTs increases significantly with increasing voltage, such that at voltages \( \geq 115 \text{ kV} \), almost all VTs are of the capacitive type. This is mainly due to problems associated with winding inductive VTs at higher voltages and the increased difficulty in maintaining the insulation between the windings.

Capacitive voltage transformers use a capacitive voltage divider (connected phase to ground - one per phase) to obtain a lower voltage supply across the last capacitor in the stack. This voltage level typically ranges between 5 and 24 kV. A small, and accurate, induction transformer is used in the base of each single phase CVT to obtain an analogue voltage, typically 120 V, for use in measuring circuit voltage.

CVTs use wrapped paper to form small capacitors, which are then stacked to form the capacitive voltage divider. Insulation of the CVT (around the capacitors and the inductive transformer) is maintained by oil immersion.

Figure 14 shows a typical capacitive voltage transformer.

![Figure 14: Capacitive Voltage Transformer](image)

Together with the primary measuring function CVTs can also be used to moderate transient recovery voltages as may occur in the interruption of short line faults by circuit breakers.

Current transformers are wound inductive type transformers that are used to obtain an accurate low current analogue of HV currents. Rated CT secondary currents are either 5 A or 1 A. In North America the 5 A secondary rating is typically used. Current ratings are defined by Standards; in Canada the applicable Standard is CSA C13. CTs typically use oil as the insulating medium. However, Hydro One has a small number of SF₆ insulated CTs.
Instrument transformers must produce current and voltage waveforms reliably for use in control, relaying and metering circuits. The acceptable limits of accuracy are outlined in CSA C13. The following outlines the acceptable accuracy for current and voltage transformer applications.

For relay systems, the VTs must be accurate to 1% or 3%, depending on the accuracy class required (1P or 3P), over their applicable rated output range. There are 5 standard output ranges or burdens that are commonly specified, namely: W – 12.5 VA, X – 25 VA, Y – 75 VA, Z – 200 VA and ZZ – 400 VA. For metering systems, the VTs must be accurate to 0.3% over their applicable rated output. Similar standard output ranges or burdens as for relay applications apply. For some applications where harmonic waveform capture is required, special VT accuracy limits are required. Such special limits are separately covered in the Standards.

For relay systems, the CTs providing input current to relays must be capable of a nominal accuracy under rated conditions; but must be capable of producing 20 times rated output current, at an acceptable accuracy, under fault conditions. In North America, CTs used for relay systems typically must have a 10% accuracy at an output of 20 times nominal CT current, or 100 A for a 5 A rated CT. The CT must also be capable of a stated voltage output at the 20 times nominal secondary current.

For metering systems CTs must be capable of much higher accuracy than for protection applications; but they do not need to be capable of accurate output at the extreme currents encountered during a fault. For revenue accuracy circuits in Canada, the accuracy of a CT output must be 0.3% at rated current and the CTs must be certified by Measurement Canada. The second portion of the specification of a metering accuracy CT is the rated burden into which the CT must supply its rated current. Standard burdens in North America range between 1 and 3 ohms.

2.5 Station Insulators

Insulators are used in transmission stations for termination of conductors at structures and to support busses or equipment e.g. disconnect switches, circuit breakers, instrument transformers, etc.

Station insulators are subject to both electrical and mechanical stresses at the installation point. The electrical stresses are caused by the high voltage between live parts during normal and abnormal conditions. Abnormal conditions may include lightning strikes and operation in contaminated conditions. Sub-optimal insulator design or deteriorated conditions may result in loss of electrical withstand capability of the insulation leading to flashovers. Mechanical stresses include compression, torsion, tension and cantilever forces.

Corrosion of metal fittings, damage due to vandalism, and cement growth are some of the factors that adversely affect the mechanical integrity of the insulator. Extreme environmental conditions, such as harsh winter weather and industrial pollution, also reduce the mechanical and electrical strength of insulators. Insulator units with resistive glazed (RG) porcelain posts or having a
silicone coating are often used to improve the withstand capabilities under these specific conditions.

The most common materials used in insulators are porcelain, glass and polymeric. The vast majority (over 99%) of the station insulators in the Hydro One system are porcelain type insulators. Glass is used mostly for insulator strain and idler discs or polymeric type insulators are used mostly at lower voltages.

The types of insulators used in transmission stations are:

- Rigid support insulators mostly used for rigid bus support.
- Disc types for strain bus connections and for idler strings associated with strain buses

Rigid Insulators

Rigid insulators consist mostly of the “newer” station post type as shown in Figure 15 or the “older” cap and pin type as shown in Figure 16. These insulators isolate live apparatus from station structures and provide support for electrical conductors and equipment. They are also an integral component of disconnect switches, and capacitor banks etc., and these are also discussed as part of each asset class. Demographic data includes all insulators, irrespective of application.

![Figure 15: Station Porcelain Post Insulator](image1)
![Figure 16: Station Cap and Pin Insulators](image2)

Cap and Pin

The cap and pin insulator forms the majority of the station insulator population. Single units are applied at the low voltage levels below 50kV and cap and pin insulators are capable of modular stacking for use at 115kV and 230kV. Cap and pin insulators were manufactured from the early 1900’s to the 1980’s but this design of insulator is no longer available.
Cap and Pin insulator failure modes include radial cracking, circumferential cracking (also called doughnut cracking), head cracks, and punctures. Radial and circumferential cracks occur in the shed and although very fine, they are usually visible upon close inspection. Radial cracks can extend up into the insulator head. Head cracks and punctures are often hidden beneath the cap, and therefore are not amenable to detection by inspection. In addition, a large percentage of cap and pin insulators manufactured between 1965 and 1980 are experiencing premature end of life due to a condition called “cement growth”, which causes the cement that holds the metal cap to the porcelain skirt to expand when moisture penetrates the cement, thereby separating, or breaking the insulator. Over 17% of the cap & pin insulator population fit into this profile. Failures of cap and pin insulators are of particular concern where they support under-hung buses or disconnect switches since personnel safety and damage to adjacent equipment is a major risk.

**Station Post**

These are one-piece or multi-piece porcelain or polymeric insulators with relatively small but numerous rainsheds and fitted with metal caps and base at the ends. The end caps and bases have tapped mounting holes to facilitate various mounting configurations. The number of insulators used in a stack depends on circuit voltages and design standards. These insulators are available with a variety of voltage ratings and cantilever strengths.

The post type insulator is used as a replacement for aging or defective cap and pin insulators. All new insulators purchased are of the post type. Single post insulators are used from 7.5kV to 115kV and stacked together for use at 230kV and 500kV. Polymeric post insulators are typically only applied at the low voltage level.

Post type insulators are constructed in a variety of ways as described below:

- **Multi-cone** – these insulators were developed as an alternative to cap and pin and station post type insulators. The multi-cone post insulator is an assembly of porcelain cones stacked together to form the desired insulator length and loading characteristics. The porcelain cones are held together with a cement compound. Multi-cone insulators are used at 230kV with BIL ratings of 900kV and 1050kV and 500kV having BIL ratings of 1550kV and 1800kV. One of the problems associated with this type of insulator construction is the effect of cement expansion on the porcelain due to temperature cycling, including freezing and thawing of the insulator. This expansion is caused by moisture being absorbed in the cement during its many years of life. The expansion causes longitudinal cracks to appear and weaken the insulator electrically. The insulator will weaken mechanically as more cracks develop. These insulators are no longer available.

- **Hollow Core** post insulators were developed to improve the firing and curing process during manufacture. Hollow core insulators allow for a more even heating of the porcelain due to its thinner walls. Fusing a porcelain or rubber plug into the hollow post during firing prevents breathing and ensures a clean, dry interior. The sealing process on some of the insulators was substandard and allowed moisture ingress, which caused a reduction in its dielectric properties and ultimately electrical failure. These insulators are
usually installed at the low voltage levels (below 50kV) and were supplied as part of the disconnect switch by some manufacturers. Only a few such hollow core insulators exist on Hydro One disconnect switches. It is not possible to visually distinguish hollow core from solid core insulators. These type of insulators are also used as the support insulators for air blast and live tank SF6 circuit breakers.

- **Solid Core** - this post insulator is solid porcelain with the metal flanges cemented directly onto the porcelain. Because of the size and thickness of the porcelain, curing of this type of insulator is critical to ensure a high quality product. Improperly cured porcelain will allow for some give, which can progress into circumferential cracking which reduces the mechanical strength. To date, few problems have been found with this type of insulator. These units are installed at all voltages from 7.5kV to 500kV and Hydro One is currently purchasing these insulators from several manufacturers.

- **Conductive/Resistive Glaze type** – post insulators can also be supplied with a semi-conductive glaze, which inhibits arcing, and flashover caused by pollution, contaminants and high humidity. These insulators are known as conductive glaze/resistive glaze (RG insulators). A small current flow over the resistor created on the surface of this type of insulator warms the surface to a few degrees above the ambient temperature. This discourages moisture accumulation. Moisture accumulation is usually necessary to make contaminants conductive. These insulators are installed at selected, high contamination locations.

- **Polymeric** – these insulators were developed in the early 1970’s and are used in stations rated between the 15kV to 115kV levels. The insulator is constructed around a fiberglass reinforced resin core rod. The outer shell is made from polymeric or silicone based polymeric material. The polymeric type is equivalent in voltage characteristics, strength and physical size to standard porcelain insulators. Silicone base type is equivalent in withstanding contamination to the RG (resistive glaze) insulators. The silicone based insulator releases silicone from its base polymeric material, which encapsulates any contaminates. This hydrophobic property prevents moisture clinging to the contaminants and reducing the dielectric strength. Polymeric insulators are lighter and less susceptible to damage during installation and maintenance than the porcelain type. These insulators are in limited use at Hydro One stations, primarily being applied at the low voltage levels.

**Strain Insulators**

These are insulators installed on station structures, in either a horizontal or vertical position, and under continuous tension, suspending a flexible wire conductor. Strain insulators may also be installed as mid-span openers. Insulators installed in this manner are not normally electrically stressed, as they are by-passed by a conductor or switch blade and used to sectionalize or isolate sections of a bus or distribution feeder. During the isolation or switching process, the jumper / blade is removed or opened, thereby putting the insulator under electrical stress.
Strain insulator units may be damaged by electrical puncture, cement growth, breakage, or severe deterioration of the porcelain, which weakens the dielectric strength of the insulator string. As the number of defective individual units in the string increases, there is an increased risk of flashover, particularly under stress conditions, e.g. lightning or faults. These insulators may also lose mechanical strength due to cement growth under the cap or around the pin. Mechanical failure can result in the conductor falling on other live conductors or transmission equipment. Because of past failures, mid span porcelain insulators must pass electrical testing before they can be used as electrical isolation. Glass and polymeric insulators installed in this manner do not have to be tested prior being used as isolating points. This makes glass and polymeric the preferred choice for these installations.

Approximately 99% of station strain insulators are porcelain, with the remaining 1% made of glass or a polymeric material. Over 30% of strain insulators in the stations are 50 years of age or greater, and are considered to be at the end of their design life.

- **Porcelain** – these are modular solid heat-treated porcelain insulators with a ceramic glaze surface and metal fittings cemented onto both ends. The metal fittings facilitate connecting individual insulators together to form a string of insulators. The number of units assembled into a string is dependent on the circuit voltage and design standards. The assembled length can vary from 300mm for 7.5kV to 5 meters for 500kV. The strength of the strain insulator is classed as KIP (thousand inch pounds) and is available in 15, 25, 36 and 50 KIP ratings.

- **Glass** These are modular high impact glass insulators with metal fittings cemented onto both ends. Application and rating of glass insulators closely follows that for porcelain but their condition can be more readily assessed. Glass insulators are understood to be in good condition as long as they are visually intact. Glass insulator skirts shatter if there is a defect, making visual inspection a satisfactory test.

- **Polymeric** - these insulators are constructed around a fiberglass reinforced resin core rod. The outer shell is made from polymeric or silicone based polymeric material. Metal end fittings facilitate connecting and mounting of the insulator. The equivalent polymeric must be longer than the glass or porcelain type it replaces. This longer length is required because the polymeric has smaller skirts, which reduces the tracking length and wet/dry creepage distance. Similar to glass, polymeric insulators are understood to be in good condition as long as they are visually intact. The polymeric insulator is much lighter than the porcelain or glass type.

Hydro One and many other utilities have experienced the failure of polymer strain insulators (also called composite or non-ceramic insulators) used as dead-end and as suspension insulators. The root cause of the failures is aging of the rubber material as a result of high electric fields (E-fields) close to the energized end. These failures have raised concern about the health of the insulators remaining in service and stressed the need to determine actions for either life extension or replacement in order to maintain high system reliability. The failure of dead-end insulators poses a larger threat to system integrity than the failure of suspension insulators because failures may result in a downed conductor. In addition, studies have shown that dead-end insulators are exposed to higher E-field magnitudes than suspension insulators. These high E-field magnitudes
may result in corona discharge activity that damages the polymer housing and end fitting seal. In the past, most work focused on insulators installed at 230 kV and above, resulting in the use of corona rings at these voltages. Recent experiences indicate that 115- units may be more susceptible because they are generally installed without corona rings and often on structures with closer phase spacing.

2.6 Station Cables and Potheads

Station cables and potheads are associated with equipment located within the confines of a transmission station, such as station service transformer feeds, transformer to switchgear connections, and capacitor bank connections. Hydro One manages transmission station cables and potheads typically with voltage between 13.8 kV to 44 kV. Cables and potheads are typically used when air insulated bus cannot be utilized, because of space limitations.

Transmission Stations cables are typically short (in length) and are usually enclosed, in ducts. Typically, the cables are inspected visually as part of regular station inspection. The inspections include checking for visual evidence of cracks, corrosion, overheating or distortion of the visible sections of the cables and physical damage or compound leaks from the potheads. These practices are consistent with the practices of other leading electric utilities.

Cables consist of the following systems:
- Cables
- Splices/Joint connections
- Potheads and Terminators.

Station cable systems are subjected to a number of stresses. The type of cable selected for each application must normally consider electric, thermal, mechanical and environmental stresses.

2.7 Capacitor Banks

Capacitors are static devices whose primary purpose in power systems is the compensation of inductive reactance of other system components. They are a static source of reactive power on the transmission system that balance the inductive demand on the system and provide the necessary voltage support needed for efficient power transmission.

In general, system operators try to balance the capacitive and inductive demand on the system at all points on the system. The active power portion of the electricity supply is the portion that allows the power system to do work, for instance turn a shaft in a paper mill. The reactive component is a requisite of the power system; and its instantaneous demand quantity must be met at the load.

Most loads are inductive in nature due to the significant use of induction motors for fans, pumps, compressors and other rotating machines. Most electric motors require an inductive component to perform work. With the volume and universal presence of electric motors in our lives, the
adequate supply of capacitive VARs to balance the needs of induction motors is necessary for the efficient operation of the electric power supply system. Fortunately, it is possible to produce capacitive VARs by adding shunt capacitors to the system at a reasonable cost.

There are basically two ways that the level of VARs generated on a system may be varied. The first is by manipulating the field excitation of synchronous machines, either motors or generators; the second is to obtain the needed VARs from transmission lines. Using synchronous machines to produce VARs can be inefficient, particularly when the loads are remote from the VAR source. Transmission of VARs over a distance has a price because of the increased losses caused by VAR transmission. Further, transmission of VARs in a power system reduces the system’s capability to transmit active power.

All transmission lines produce VARs continuously. Inductive VARs are produced proportional to current levels, and capacitive VARs are produced proportional to voltage. To some extent, voltage levels in lines can be varied to produce the VARs required. During light load hours, e.g. overnight when loads are light and there isn’t much demand for inductive VARs, lines can be run at reduced voltage levels to reduce the capacitive demand on the system; the converse is true during peak load hours when the number of motors connected to the system, and thus the inductive demand, is at its peak. Unfortunately, it is often not possible to meet the inductive demand on the system without the addition of shunt capacitors. Further, given that it is more efficient to balance the inductive/capacitive needs of a system at any given point on the system, shunt capacitors often are added at different voltage levels to balance capacitive and inductive VARs out at each voltage level. The reason for this practice is that the greater the VAR demand at any point on the system, the greater the losses at that point. In most systems most capacitive compensation is installed either at the load, or at the distribution voltage level. In lightly loaded systems the level of VAR transport and thus loss at the transmission voltage level is not sufficiently of concern to justify the addition of transmission level capacitors. Hydro One however has a system that is sufficiently heavily loaded as to justify the addition of shunt capacitors at the transmission voltage level at some of the transmission stations.

A capacitor consists of two conductive plates with a dielectric material in between. The closer the plates approach and the thinner the materials the more efficient the capacitor is at producing VARs, and the lower the real power losses. In modern capacitors the plates are in fact thin gauge aluminum foils separated by thin, but effective polypropylene insulating film, impregnated with a non-PCB fluid with high insulating strength. These capacitor packs or elements are then connected together in an appropriate series-parallel arrangement and installed in a stainless steel can and the bushings are welded into position. The primary objective of the can mechanical design is to avoid fluid leakage and corrosion. Capacitor units can be obtained in the voltage range of 120 volts to 27.6 kV, and at VAR ratings ranging from a few kVAR to 625 kVAR. The most common capacitor cans in the transmission and distribution voltage range is 13.8 kV. The Hydro One capacitor banks consist of capacitor cans and interconnecting buses mounted on racks which are stacked on support insulators which are typically mounted on steel support structures so as to be usable at transmission system voltages such as 115 and 230 kV.

Individual capacitor cans, in the past, were either internally or externally fused to ensure that should a capacitor fail it will not cause a can to rupture or cascading failure of the group of
capacitors. The more recent development of the fuseless design has resulted in simplification of the bank configuration and has been applied successfully at several locations. The fusing alternatives currently on the Hydro One system are described as follows:

**Externally Fused**

This design was the technology of choice in Hydro One for many years. Each can has its own current limiting or expulsion fuse to disconnect a failed capacitor can from the bank. When one or more capacitor units are removed, the remaining parallel capacitors are subjected to an overvoltage which must be limited to a maximum value of 110% of rated voltage. External fuses provide a visual indication of a failure but banks tend to be larger, more costly, subject to animal outages and have higher installation and maintenance costs.

**Internally Fused**

The internal fuses are current-limiting fuses in action. One fuse is connected in series with each element within the capacitor. They are designed and coordinated to isolate internal faults at the element level and allow continued operation of the remaining elements of that capacitor unit. This results in a very small part of the capacitor being disconnected; therefore, the capacitor and the bank remain in service.

**Fuseless**

As a result of the high reliability of today’s all film dielectric, the use of fuseless capacitors (many elements in series), combined with the typical HV banks configuration (many "strings" of capacitor units in series), account for this design’s good performance. Some fuseless designs are based on connecting the internal elements in parallel strings, resulting in limitation of parallel energy inside the unit and not imposing restrictions on bank connections or on capacitor can size. A bank containing failed elements can operate continuously and with reduced risk of can rupture. Advantages are reduced installation and maintenance costs, less space, fewer live parts, small animal resistance and lower losses.

In order to make up shunt capacitor installations at transmission voltage levels individual capacitors cans are connected in series and parallel with each other to form capacitor banks, to achieve suitable ratings of reactive power and voltage. Small banks can be seen on distribution lines directly connected through fuses to the phase conductors. At transmission voltages capacitor banks can run to hundreds of MVAR. These capacitor banks are essentially three phase loads, which vary in reactive power and in voltage levels, ranging anywhere between 5.0 MVAR (18 cans) at low voltage level to one of the highest rating worldwide, 411.6 MVAR (1,300 cans) at 230 kV level. Figure 17 shows a typical Hydro One 230 kV ungrounded wye, shunt capacitor bank.
Capacitor banks are connected to the Hydro One transmission system at various transmission stations, depending on the proximity and size of the inductive load to be compensated. Since the inductive portion of the power level that requires compensation varies throughout the day, the amount of capacitance in the system must also be varied. This variance is for the most part achieved by varying the excitation of synchronous machines, and (more economically) by controlling the operating voltage levels of transmission lines through the switching in of capacitor banks. This means that capacitor banks could be switched daily.
2.8 Station Buses

The air insulated station (AIS) buses carry electrical energy from the incoming transmission line terminations to the substation disconnect switches, circuit breakers, transformers, reactors, capacitor banks, feeders and other associated power equipment. The buses operate at voltages ranging from 500kV down to 5kV and typically at continuous currents of up to 4000A. Normally three stranded or rigid tubular bus conductors constitute a single circuit. In most cases one conductor per phase is adequate but for some situations, such as stranded conductors used at 500kV or for very high continuous current requirements, bundled conductors of up to 4 per phase are required. The bus conductors are insulated from, and arranged on support steel structures with sufficient structural strength and clearance dimensions to prevent normal and abnormal operating currents and voltages from resulting in dielectric, thermal or mechanical failure. Rigid buses of either copper or aluminium tubing are supported on rigid support insulators of either the cap and pin or station post design. Strain buses of either copper, aluminium or aluminium conductor steel reinforced (ACSR) are supported by strain insulators.

The modern outdoor air insulated switchyards typically employs a modular, low profile bay design. This modular design concept is based on the idea of having identical bays mounted together in a manner that accommodates both the single line diagram and the available space requirements. The current design relies on the extensive use of rigid aluminium tubular buses supported by station post insulators on tubular support steel sections. The design philosophy results in a reduction in the number of different structural pieces and allows for easier and safer access to electrical components. All rigid bus connectors and other hardware are welded type to achieve higher ampacity ratings. The older high profile bus arrangement primarily consists of stranded strain bus and employs strain insulators supported on lattice type steel structures.

The conductor spacing, line-to-ground and line-to-line and the bus support intervals are determined by a variety of factors. The spacing must take into account the ability of conductors to gallop or move either vertically or horizontally during short circuit, snow, icing or wind conditions. As current passes through the conductor the resistance of the conductor causes its temperature to rise and expansion of its length. This results in increased sag for stranded conductors and increased mechanical loading of terminals, connectors, hardware and insulators supporting rigid bus conductors. Vertical safety clearances between conductor and ground must not be compromised during any abnormal operating or environmental conditions. The bus conductors must have both tensile and ductile properties in order to withstand longitudinal forces and bending movement without failure. Support intervals as well as the electrical and mechanical characteristics of the support insulators must be selected to provide an adequate safety margin when exposed to these abnormal operating and environmental conditions.

2.9 Station Surge Protection

Surge arresters on the Hydro One transmission network protect equipment costing several magnitudes more than the arresters themselves, from the effects of lightning and switching overvoltages. Surge arrester overvoltage protection is employed on the HV and LV terminals of all power transformers, on capacitor banks, at underground cable terminations and on some
critical overhead transmission lines. Over the past twenty years Hydro One has replaced the majority of the high voltage rod and pipe gap and silicon carbide arrester overvoltage devices by the more reliable and cost effective metal oxide arresters.

When properly selected, manufactured and configured, they are extremely reliable devices and can offer decades of service without causing any problems. Surge arresters constitute an indispensable aid to insulation coordination in the power systems. The overvoltages caused by lightning and switching surges can cause failures of expensive equipment such as power transformers without the use of arresters. The arresters intervene to limit the overvoltages to a safe margin below the rated insulation withstand ratings of the equipment they are protecting.

Arresters being installed today are all gapless metal-oxide (MOA) arresters. The distinctive feature of a MOA is its extremely nonlinear voltage-current characteristic which eliminates the need for the disconnection of the arrester from the line through serial spark-gaps. A leakage current of about 100 μA flows when the normal line-to-ground voltage is applied. Equipment such as power transformers have a standard lightning impulse withstand level (sometimes referred to as "BIL") based on their rated operating voltage, e.g. 900kV BIL for a 230kV rated unit. In accordance with the international standards on insulation coordination, the highest voltage in operation of an oil insulated transformer should stay below this value by a factor of at least 1.15.

The arrester has a rated residual voltage based on a standard lightning impulse test current of 10 kA. This voltage is called the lightning impulse protection level of the arrester. The protective margin of a properly rated and configured MOA located close to the transformer terminal will exceed the minimum international standard requirements by a wide margin. Operating reliability and safety of the MOA has been further enhanced by the adoption of high mechanical strength, explosion and contamination resistant polymeric housings instead of the previous porcelain housings.

Other than the periodic washing required in the more highly contaminated locations, monitoring of leakage current in some special situations and periodic station thermo-vision inspection, there is little or no maintenance required for surge arresters.

Over the past twenty years the failure rate of surge arresters has been considerably reduced by the adoption of the metal oxide technology. The failure prone silicon carbide gapped arresters currently applied on many medium voltage installations are being replaced by the metal oxide technology. Surge arrester replacement is generally integrated with other substation upgrading projects. For surge arresters the issues of degradation and assessment are similar in some respects to those for insulators and some instrument transformers. Methods of assessment and procedures for determining end-of-life based on remnant strength are well established.
2.10 HV/LV Station Structures

The majority of transmission station structures are reinforced concrete, galvanized steel and some wood poles. These are subject to inspection as part of routine substation inspection, typically on a 3-month cycle.

Degradation resulting from corrosion of the reinforcing bars in the concrete can be a very destructive process. Visual inspection can only detect this at a relatively advanced state. Deformation or cracking of the concrete is indicative of an advanced corrosion situation. Treatment is difficult and expensive, involving the removal of the concrete and treatment of the reinforcing bars. In most cases when evidence of such damage is noted the initial reaction is to make short-term repairs. These are not usually very successful and ultimately more significant refurbishment or replacement will be required. End-of-life for these structures can be defined by the presence of widespread damage (cracking of concrete spalling). Other than this, concrete structures would normally only be replaced as part of major substation refurbishment usually initiated by the need for replacement or refurbishment of the major plant or by significant development of the system.

The degradation of steel structures is mainly as a result of corrosion. The rate of degradation is very dependent on the environmental conditions to which the structures are subjected. Industrial pollution is a particular problem for galvanized steel.

For wood poles or structures the issues of degradation and assessment are the same as those for wood poles on overhead lines

2.11 Ancillary Systems - High Pressure Air Systems

Centralized HPA systems are installed at all locations that have a population ABCBs. These breakers employ compressed air as an interrupting and insulating medium. This requires a high-pressure compressed air supply consisting of a centralized HPA compressor/dryer plant as well as an air storage facility. The HPA systems are usually comprised of multi-stage compressors, chemical or heated dryers, numerous air storage receivers, extensive piping and valving arrangements, and controls.

A typical HPA system used by Hydro One is illustrated in Figure 18.
Depending on the particular vintage, manufacturer, as well as the specific design, HPA systems operate from between 600 psi (4,143 kPa) to 3600 psi (24,821 kPa).

In order to ensure reliable operation of ABCBs, it is essential that the compressed air is free from contaminants and that it contains minimal amounts of moisture. Since the air, which exits the compressors is 100% saturated with moisture vapour, a reduction of relative humidity is required to make the air suitable for operation. Filtering and drying of the air during and after compression accomplish this. Chemical dryers are now primarily used to remove moisture vapour from the compressed air. Many of the original dryers were “heated-type”, where heat was used to dry the air instead of chemical desiccant. These dryers had extensive piping and valving arrangements, which had to be switched manually on a regular basis, making them both prone to leaks and breakdowns, and very labour intensive to maintain and operate. These dryers are now older than 25 years and replacement parts and labour skilled in this old technology are no longer available. Most of these dryers have been replaced with the “heatless-type” or desiccant-based dryers. The dryer units consist of dual chambers filled with activated alumina desiccant, which dry the compressed air as it passes through the desiccant.
Storage receivers are located at the centralized compressor buildings, to ensure an adequate supply of air exists at all times. The criterion for volume availability is defined as the adequate supply for 5 C-O operations of each breaker.

The isolating valves allow portions of the air system to be isolated for maintenance, or redirected in case of a system problem. There are three dominant manufacturers that have supplied valves over the last 30 years. Two of the manufacturers have used a valve design whereby the valve seat, seals both the ball and the body of the valve. Due to this dual function of the seat, many of these valves’ body seals leak and need to be replaced.

Storage receivers are located at the individual circuit breakers, to ensure that an adequate supply of air is available to the breaker in the event of multiple, rapid succession operations. Each breaker is provided with enough air for 4 consecutive C-O (close-open) operations. The circuit breaker itself can store 2 C-O operations internally and the local storage receiver holds the other 2 C-O operations. Following the 4th successive C-O operation, the air for the next operation comes from the central air storage.

Protective devices are required to automatically prevent the supply of energy to the prime mover of the compressor when an abnormal condition occurs during the compressor operation. All air compressors are required to have protective devices for the following:

- High discharge air pressure
- High discharge air temperature
- High discharge cooling water temperature
- Low lubricating oil temperature

Hygrometers are used to measure the dew point at the outlet of desiccant air dryers to insure the air is correctly conditioned.

### 2.12 Batteries and Chargers

Circuit breakers, motorized disconnect switches, transformer tap changers, and in particular the communication, protection, and control systems in transmission stations must be provided with a guaranteed source of power to ensure they can be operated under all system conditions, particularly during fault conditions. There is no known way to store AC power thus the only guaranteed instantaneous power source in switchyards must be DC, based on batteries. All Hydro One’ transmission stations are provided with at least one DC system, comprising a battery, battery charger, and a DC distribution system made up of DC breakers, fuses and associated cable distribution system. Battery systems designated as Station Batteries supply all protection and control and other station ancillary DC services while Telecom designated batteries supply communication system DC requirements at selected stations.

Transmission stations typically have two redundant sources of AC station service power. Bulk Electricity Supply (BES) stations have duplicate station chargers and batteries, whereas Dual Element Spot Network (DESN) stations have only one battery-charger system, in compliance
with the requirements of the Northeast Power Coordinating Council (NPCC). The chargers are fed from the AC auxiliary system at 600, 208 volts (3 phase) or 240, 120 volts (1 phase). Typical battery output voltages are 48, 125 and 250 volts. The 48 V battery voltage is usually reserved for communications (Telecom) service, however on the Hydro One system, there is a large number (approximately 70) legacy 48V station batteries used for supply of control panel boards and associated relays. The Station 48V batteries are completely separate and distinct from the Telecom 48V battery systems. The 125V and 250V batteries are used for station protection and control and other ancillary DC services.

A battery charger is an electronically controlled rectifier that is designed to carry the continuous station load over a specified period while simultaneously recharging its battery. The charger has controls that regulate its output voltage to ensure constant voltage irrespective of current output, and current output limits to protect the charger from excessive output demand. It normally also has a boost voltage setting to ensure occasional battery conditioning charging sessions. Chargers are also usually fitted with assorted alarms, including a ground detector alarm for use in ungrounded systems. Figure 19 shows a typical battery charger.

Figure 19: Battery Charger

Transmission stations require rechargeable batteries. There are only two basic types of rechargeable batteries: the nickel–cadmium type and the lead-acid type. In common with most utilities Hydro One use the lead-acid rechargeable cells due to the higher cost and perceived problems with the operation of nickel–cadmium cells.

There are two types of lead-acid cells: lead-antimony and lead-calcium. Hydro One prefers lead-calcium cells due to their longer life, and lower maintenance requirements. Historically, the vented (flooded or wet cell) type battery has been used exclusively by utility users of batteries. A newer type of cell, the valve regulated lead antimony (VRLA) cell was introduced and a number of utilities have migrated to their use because this type of cell has the advantages of a lower space requirement, lower rates of gas evolution, lower safety related costs, and expected lower maintenance requirements. Hydro One has discontinued such installations due to the fact
that the life expectancy of valve regulated cells to be significantly less than that of wet cells. Figure 20 shows a typical wet cell battery installation:

![Figure 20: Typical Battery System](image)

The Hydro One standard for battery sizing is in-line with industry standards and ensures that a single battery can carry the entire station load without any AC feed to the chargers for 6 or 8 hour period depending on the station criticality. Typical protection and control battery sizes for step down transformer stations range from 30 to 900 Ampere Hours (AH) while the BES stations are normally equipped with redundant battery systems that range between 180 and 1495AH.

### 2.13 Station Grounding Systems

Grounding systems are designed to ensure safety of personnel and equipment in and around transmission stations. Grounding systems provide a means of ensuring a common potential between metal structures and equipment accessible to personnel so that hazardous step, touch, mesh and transferred voltages do not occur. In addition, effective grounding systems limit the damage to equipment during faults or surges and they ensure proper operation of protective devices such as relays and surge arresters. The basic design of an effective grounding system is required to:

- Provide grounding of all conductive enclosures that may be touched by public or staff personnel thereby eliminating shock hazards.
- Limit voltage in the electrical system to definite fixed values of step and touch potentials to ensure public and staff personnel safety.
- Limit voltage to within insulation ratings of equipment.
- Provide a more stable system with a minimum of transient over-voltages and electrical noise.
- Provide a path to ground for fault currents to allow quick isolation of equipment with operation of ground fault protection.
- Reduce static electricity that may be generated within the facilities.
- Provide protection from large electrical disturbances (such as lightning) by creating a low resistive path to earth.
The Canadian Electrical Code (Sections 10 and 36) and IEEE Guide for Safety in AC Station Grounding (IEEE STD 80) stipulate the requirements for the design of these systems. Hydro One has followed its own standard “Ontario Hydro Transmission and Distribution Grounding Guide, 1994” for design of these systems at its stations.

Soil resistivity measurements at the station location are required to design an adequate grounding system. Once the grounding system has been installed, it is tested and verified with ‘fall of potential’ measurements.

Over the period that Hydro One’ transmission stations have been in existence there have been some changes in the applicable standards. These, in general, have led to reductions in the permitted maximum potential rise and in step and touch potentials. However, the biggest change during this period has been the ability to accurately model the effectiveness of grounding systems. Traditional “manual” calculations will have been used to design many of the existing stations. These were not able to provide complete definition of potentials and fault conditions. Grounding system installations are typically classified as permanent or temporary systems, as described below.

**Permanent Grounding Systems**

Grounding systems are comprised of predominantly copper conductors connected together into a mesh that is buried and bonded to all station structures. A typical station grounding system is depicted in Figure 21 and consists of the following:

- 4/0 AWG bare copper conductors buried 12 to 18 inches below grade in a grid pattern that are spaced 10 to 20 feet apart.
- At ground conductor crossings, the conductors are securely bonded to each other.
- Ground rods are securely bonded to the grid at corners, and at junction points along the perimeter. Redundancy in these connections is a requirement.
- Fences, buildings (control, maintenance or administration) are tied to the main grid as well as to water service pipes.
- Any outgoing circuit shield wires and cable shields, as well as station fence ground are also bonded to the station ground grid.
All above grade metallic facilities including structures, transformers, breakers, and fencing would be securely bonded to the grid with grounding conductors as shown in Figure 22. Additional ground rods would be securely bonded to the grid at major facilities and particularly at surge arrester locations. One type of service that is normally isolated from the ground grid is telephone service using metallic pair cable. Such cables are typically isolated from ground in order that exterior telephone equipment is not damaged by the high voltage spikes that are observed in ground grids during faults.

The station security fence may, or may not, be bonded to the station ground grid depending on several factors such as the minimum distance from the fence to grounded station equipment,
whether a rail siding enters the station or whether the gates incorporate telephones, card readers or electric gate locks.

**Temporary Grounding Systems**

Temporary grounding and bonding systems are installed for personnel safety when working on de-energized apparatus. These are required to eliminate hazardous induced potential differences caused by adjacent energized conductors, residual charges on capacitive circuits or accidental re-energization of circuits or apparatus.

**2.14 AC/DC Station Service Equipment**

All Hydro One transmission stations are provided with designated AC and DC station service systems. These are the supply systems that provide AC power to the auxiliary equipment in the station such as battery chargers, fans, pumps, HVAC and lighting and DC power from the batteries to control, metering, telecommunication, SCADA, circuit breaker and switch control and operation.

The rating and configuration of these station service systems depends on the function, criticality and rating of the specific transmission station. The stations are categorized as bulk electricity system (BES) stations and dual element spot network (DESN) step down transformer stations. Several of the station service systems are dual feed arrangement to ensure reliability and to minimize the impact of any local supply problems. In all cases, any loss of supply would automatically trigger an alarm.

**DC Station Service**

The DC station service (DCSS) supplies critical transmission station protection, control and annunciation equipment that operate (trip and close) circuit breakers, circuit switchers, motor operated disconnect switches and emergency lighting.

The main components of DC Station Service distribution system (excluding the batteries and chargers which are evaluated in a separate document) are transfer switches, main and subordinate distribution panels, cables, fuses and other service breakers etc. The DC station service must remain functional for a period of time (6-8 hours) after the initial loss of the charger supply, and capable of operating breakers to re-establish AC supply at the end of that period.

Typical battery output voltages are 48, 125 and 250 volts. The 48 V battery voltage is usually reserved for communications (Telecom) service, however on the Hydro One system, there is a large number (approximately 70) legacy 48V station batteries used for supply of control panelboards and associated relays. The Station 48V batteries are completely separate and distinct from the Telecom 48V battery systems. The 125V and 250V batteries are used for station protection and control and other ancillary DC services.
The DC Station Service reliability requirements are determined based on compliance with regulatory and planning requirements. For bulk electricity system (BES) stations, the DC station service design requirements must comply with the TSC, NPCC, and IESO to maintain the adequacy and security of the transmission system. The design of the station service system shall ensure that if either the battery charger fails or the AC supply source fails, the station battery bank shall have enough capacity to allow the station to operate for at least eight hours for a single battery system or at least six hours for each of the batteries in a two battery system.

Hydro One is obligated to comply with various NERC Standards and NPCC Criteria related to emergency operating procedures and system restoration. More specifically, the NPCC Criteria Document A-03 “Emergency Operation Criteria”, section 4.10.1 (System Restoration - Testing Requirements), details a number of tests that must be performed regularly at certain stations to ensure that facilities are available when required. Hydro One has identified a total of 70 stations that are on the list of key facilities needed to initiate restoration following a blackout (Basic Minimum Power System, BMPS).

The DC station service must ensure a high degree of dependability and must ensure that no single contingency or common mode failure results in the loss of critical relay protection or automatic tripping of power circuit breakers. This is achieved by having duplicate battery banks and rectifier/charger sets (“A” and “B”), each capable of supplying the total DC station load, with a DC transfer scheme to switch the supply between the “A” and “B” sources.

For BES stations, this requires that “n-2” system design criteria be applied to the design of the DC station service. That is for pre-contingency planned or forced outage of the station “A” battery or associated charger or AC supply source, loss of a subsequent DC supply element (i.e. “B” battery or associated “B” charger or AC supply source) must not result in loss of critical relay protection or automatic tripping of power circuit breakers.

For Dual Element Spot Network (DESN) transformer stations, a single battery/charger system is to be used. AC supply to the charger is to be from an automatic transfer switch fed from both AC station service panels. The single station battery must have enough capacity to allow the station to operate for at least eight hours following the loss of the charger or the AC supply source.

Where a single battery system is used, the following conditions shall be met:

a. It can be tested and maintained without removing it from service;
b. Each protection system shall be supplied from physically separated and separately fused direct current circuits;
c. No single contingency other than failure of the battery bank itself shall prevent successful tripping for a fault.
d. Critical DC supplies shall be monitored and annunciated such as relay protection circuits and high voltage interrupters (HVIs).
e. For tap transformer stations, one protected (fuse/breaker) monitored DC station battery system is required unless two systems are provided.
The Transmission System Code (TSC) Section 10, “Protection System Requirements” requires that telecommunication battery and DC system design shall ensure that systems are:

(a) designed to prevent unwanted operations such as those caused by equipment or personnel,
(b) powered by the station's batteries or other sources independent from the power system, and
(c) monitored in order to assess equipment and channel readiness.

DC transfer switching refers to the station service level transfer of DC load supply from its “normal” supply source to an alternate source of supply following an equipment outage (and loss of the “normal” supply) or for the purpose of carrying out maintenance. Hydro One currently has three types of DC transfer schemes installed; these are:

(i) **Automatic:** Upon loss of “normal” supply this scheme automatically transfers to an alternate source of DC supply.

(ii) **Semi-Automatic:** Operator intervention is required once to transfer to an alternate source of DC supply.

(iii) **Manual:** Operator interaction is required to transfer load supply to an alternate source of DC supply.

**AC Station Service Systems**

All transmission stations (BES and DESN) have at least two redundant AC station service systems comprising station service transformers, fuses, LV circuit breakers, transfer switches, load centers, panelboards and associated cable distribution system. An additional third source of AC station service such as diesel generators or supply from the local area distribution system must be provided for Bulk Electricity Supply (BES) stations

Hydro One reliability requirements for AC station service systems are established to comply with regulatory requirements of the Ontario Transmission Code, NPCC criteria for bulk power and interconnected system protection, design and operation and also with the requirements of the Independent Electricity System Operator (IESO) of Ontario.

In general requirements for bulk power system facilities are that there shall be two sources of station service AC supply, each capable of carrying at least all the critical loads associated with protection systems.
For existing BES stations there are two common variations of the standard AC Station Service supply configuration. The configuration for the larger existing BES stations, having more than two autotransformers consists of three independent sources of AC supply and LV switchgear configured to provide supply to four main AC load distribution centres/panels. Another variation also incorporates three sources of AC supply but provides supply to two main AC load distribution centres/panels

In the future the new, larger BES stations will be supplied by three independent sources but with a less complex and cost effective switchgear configured to supply three load centers/panels only. For new BES Switching Stations or new BES Stations with two or fewer autotransformers, the standard configuration requires that only two independent AC sources of supply be provided to supply two main AC load distribution centres/panels.

For DESN stations the configuration provides two independent AC station service supplies connected so that an outage to a single element will not result in the prolonged loss of both supplies. An emergency connection between the AC supplies is provided so that either supply can be connected to supply the entire station service load. New DESN stations are being supplied by simpler and more cost effective load transfer switchgear.

AC transfer switching refers to the station service level transfer of AC load supply from its “normal” supply source to an alternate source of supply following an equipment outage (and loss of the “normal” supply) or for the purpose of carrying out maintenance. Hydro One currently has three types of AC transfer schemes installed; these are:

(iv) **Automatic:** Upon loss of “normal” supply this scheme automatically transfers to an alternate source of AC supply.

(v) **Semi-Automatic:** Operator intervention is required once to transfer to an alternate source of AC supply.

(vi) **Manual:** Operator interaction is required to transfer load supply to an alternate source of AC supply.

To comply with regulatory requirements that specifies eliminating the possibility of a single contingency or common mode failure disabling the entire AC system, fully automatic AC transfer schemes are to be avoided or eliminated. Manual only AC transfer schemes are also to be avoided for switching safety reasons.

The standard for all new and replacement installations requires semi-automatic AC transfer schemes to be provided with remote-OGCC and remote-local initiation and full manual mode override capability. Simple, double throw positive action, automatic transfer switches are to be used downstream of the station service supplies and directly for essential/critical AC loads (e.g. transformer cooling, circuit breaker heaters and auxiliaries, battery chargers). All AC transfer switching schemes use "Break-Before-Make" type switching to prevent paralleling of station service sources.
Each DESN TS has two independent AC station service supplies fed from adequately rated station service transformers connected separate buses on the LV switchyard and arranged so that an outage to a single element will not result in the prolonged loss of both supplies.

The station service transformer ratings are selected to cater for the ultimate DESN TS loads. The secondary system is 120/208V, 3-phase, 4-wire. The transformers are typically rated at 200kVA, with a secondary voltage of 120/208V, 3-phase. Typically there is a 600A transfer switch connection between the two AC supplies is provided so that either supply can be connected to supply the entire station service load.

2.15 Station Buildings

Hydro One owns a number of buildings of different types and sizes, located in or adjacent to transmission stations, and spread throughout the province. These buildings can generally be categorized as:

- Control Buildings
- Auxiliary Systems Buildings
- Occupied Buildings
- Ancillary Buildings.

The Control Buildings are used primarily to house protection and metering equipment, batteries, and control and communication systems. Auxiliary Systems Buildings are buildings used for housing technical equipment such as metalclad switchgear, air compressors and dryers, and oil processing and storage equipment. Occupied buildings include maintenance centers, operation centers, and offices. Ancillary buildings include garages, stores etc.

These buildings have been constructed over a long period of time to meet the particular needs of the time and constructed in accordance with required building standards. Thus, the buildings consist of a wide variety of designs and construction materials e.g. size varies from less than 100 sq. ft. to several thousand sq. ft. depending on the application and these may be made from ornamental brick, concrete block, engineered metal or other prefabricated material.
2.16 Fences

It is Hydro One’s practice to erect security fences around their electrical plant facilities, including transmission stations and exposed high voltage cable terminations. This practice is for the purpose of protecting the public from hazardous electrical contacts, and to protect these facilities against intrusion and vandalism.

Types of Fence

The security fences can be of several types such as steel chain link, aluminum chain link, wood, masonry and Durisol. All the above types of fence have been installed at transmission stations owned by Hydro One. Chain link fences are by far the most widely used type of fence and constitute about 99% of the total length of fence installed. This type of fence comprises fence fabric, galvanized support posts and top rail, bottom tensioning wire, barbed wire on top, support brackets, concrete foundations, gates, warning signs and grounding mechanisms. The fence fabric is generally galvanized steel, but aluminum fabric is also used in certain cases.

The other types of fence such as walls of either solid masonry, metal or Durisol may provide an additional degree of security. Solid walls are generally more difficult to breach and also prevent a direct line of sight to equipment inside the station. Solid walls may also prevent vandalism from outside the fence, such as by projectiles (e.g. rocks). The probability of such damage actually occurring depends on a number of variables including the height of the wall, surrounding terrain, and elevation of the equipment inside the station. The material utilized for this type of fence is generally commensurate with the evaluated security risk of the area. As stated earlier, most of the fences at the stations owned by Hydro One are of the chain link type.

Technical and Legal Requirements

The minimum design height of the fence specified by Ontario Electricity Safety Code is 1.8 metres. The standard fence design adopted by Hydro One follows IEEE Standard C2-1997, which requires a minimum chain link fence height of 2.13 metres of fabric, with an additional 0.3 metres extension composed of three-strands of barbed wire at the top. The other important requirements in fence design are: the gap under the fence, between the fence and grade must be less than 25 mm, a 50 mm maximum gap between the gate pipe frame and the gate support posts, and lastly a proper grounding system for the safe grounding of the fence.

Gates are provided at suitable locations around the fence to allow access to authorized persons and vehicles. Depending on security requirements at a particular site, the gate control mechanism is designed to provide one of: automatic vehicular access, manual vehicular/personal access, manual personal access, or manual vehicular access.

In order to warn the public of the danger and to discourage entry by unauthorized persons, approved danger and warning signs are posted at all gates that allow access to transmission stations and other hazardous locations. Such signs are further posted at regular intervals (normally 10 m) along the fence.
2.17 Station Fire and Security Systems

The Security and Fire Protection asset class includes systems for protection of transmission facilities from the threats of fire, break-ins and vandalism. Hydro One owns a large number of transmission stations and buildings of different types and sizes and has installed some form of security and fire prevention measures for protection of the various facilities at each of these locations as described in this Asset Description.

Security Systems

The primary physical barriers provided at all locations to prevent unauthorized entry into Hydro One facilities are the site perimeter fencing or walls. These fences and walls constitute a separate asset class, and thus are not further discussed herein. The security systems in the asset category include additional measures ranging from conventional simple door control security systems to video surveillance facilities.

The form and degree of sophistication of the security systems at these stations/buildings varies widely. The primary reason for this degree of latitude being that, in the beginning, security systems at many locations were installed as a result of ‘reactive after the fact’ approaches following incidents. Another factor to consider is that a significant number of stations in the past were manned thus no extra security arrangements were required. This is no longer the case. Security requirements have therefore changed in recent years resulting in a need to develop a strategy for standardization for security systems. This standardization process is still in the evolving stages.

Generally, three types of security systems have been employed at transmission stations. The simplest types include simple door and gate control systems, often padlocks, to permit entry to authorized personnel only, and motion sensor triggered lighting installations. Note that in many cases, there are third parties that have access to the station premises. Typically, the third party installs its own lock and opening either lock provides access to the site. A first step in enhancement of the security level at transmission and distribution stations is the replacement of the locks and the implementation of a new key management system to control access to the sites. The second types include motion detection and alarm systems within buildings. The third type includes microprocessor surveillance of the motion detection and modern slow scan video surveillance systems, with both of these types of systems wired to supervisory control and data acquisition systems (SCADA) to allow central monitoring. The latter types of systems are installed at only a few sites at present.

At a number of locations, security monitoring is part of the fire detection system or the heating, ventilation and air-conditioning system. Hydro One has control centers at 10 locations; and each of these centers monitors a number of stations. As part of the development of a standardized security policy and system, it is planned to centralize the monitoring function to a master control centre.

Fire Protection Systems
Fire protection systems at transmission facilities are primarily of two types; those associated with buildings and those associated with equipment.

2.18 Buildings and Indoor Equipment

In a manner similar to the practices followed by Hydro One for security systems no standardized practices for fire detection and prevention have been established for general building areas. Buildings constructed after 1985 have fire detection systems installed; whereas some of the older buildings do not have even simple smoke detectors. Other types of systems installed for fire control in buildings include:

- Carbon dioxide based systems
- FM 200 systems. These have replaced the now unacceptable Halon based systems that had been installed at some locations.
- Sprinklers. These are normally installed in all basements with areas over 300 square feet.
- Fire hoses connected to municipal water systems are provided inside some buildings.

Certain indoor equipment, such as oil-filled transformers and oil-filled cable potheads, require dedicated fire protection systems such as water deluge systems with associated hose cabinets. Such systems are provided to meet the requirements of National Fire Protection Association (NFPA) Standard No. 15; and they include fully automatic air supervised, or electrically supervised, cycling type, dry pipe, open head deluge systems for all major indoor fire hazards, such as those noted above.

Deluge systems generally consist of open head spray nozzles attached to a piping system that is connected to a water supply through a deluge valve. The valve is opened by the operation of a fire detection system installed in the same area as the nozzles. When this valve opens, water flows into the piping system and discharges from all nozzles. This type of system uses high-velocity water sprays of a relatively large droplet size directed against convection air currents; and the system is designed to extinguish fires on, under, or immediately around protected equipment.

Outdoor Equipment

Oil filled transformers in outdoor stations are equipped with fire detection systems. The monitoring of heat detectors is handled through SCADA systems to the respective control centres, or through the dedicated fire detection panel to the SCADA system and then to the control centres. Only a few transformers, at attended, rather than unattended, Stations, are without this system. Other outdoor equipment, with the exception of oil filled cable terminations are not considered vulnerable to fire and thus they are not fitted with fire detection systems.
2.19 Station Drainage, Oil Spill Containment and Geotechnical Systems

The Transmission Drainage and Geotechnical asset class includes drainage facilities for the removal of surface and ground water, and civil work facilities such as roads, yard compaction and surfacing, and footings.

Drainage Systems

Transmission and switching stations require drainage facilities for the removal of surface and ground water. Drainage is a practical and economical way of improving and maintaining firm, dry, stable sub grades for support of roads, railways, and foundations for structures and buildings.

The two basic sources of subsurface water are the presence of a high ground water table, and precipitation (rain or snow melt) seepage into the soil. When water seepage encounters an impervious layer of soil, water is retained and forms pools, which increases the ground water table level. Occasionally, subsurface soil formations result in upward water flows, or springs. These, when they occur within stations, must be capped and the water diverted off site to ensure the water doesn’t compromise the subsurface soil integrity, or cause grounding problems. Foundation under-drainage protects basement slabs against hydrostatic uplift and flooding of basements. Road under-drainage helps to minimize frost heaving and frost boils. Inadequate drainage can compromise maintenance and construction access for heavy equipment; and thus can cause a personnel safety hazard.

Many stations have drainage systems, which consist of main drainage and under-drainage. Main drainage is a system of catch basins, buried piping and manholes, including necessary pumps, all as required to suit the station site. The system also includes connections for building rainwater drains and transformer oil spill containment system drains. Under-drainage consists of buried perforated piping connected to the main drainage. This type of drainage pipe is provided to allow drainage of sub-surface water from graded areas, roads, parking areas, railroads and cable trenches. Sumps and sump pumps are included in under-drainage systems, where required.

Many stations exist without a main, or under-drainage systems. In such cases, runoff percolates over the yard surface, which is sloped to ensure drainage, and the water finds its way to a ditch off the station active surface.

Over the past 20 years there has been growing awareness of the need to contain oil spillage from major plant. Growing awareness of environmental issues and tightening of legislation and increased penalties have forced electric utilities to address this issue in a more systematic and consistent fashion. Prior to this period, oil containment was a feature for major transformers but the application was varied and non-uniform. Over the past 20 years, the onus has been on ensuring that the oil containment systems for all major transformers are to a uniformly high and acceptable standard.

Transformer spill containment systems are operated to release runoff to drainage systems, except during oil spills when the containment connection is shut off by a special pump located in a
This sump may be connected to one or several spill containments; and it is not considered part of the drainage system.

Maintenance and ongoing management of oil containment systems is generally limited to visual inspection as part of routine substation inspection with functional checks on pumps used to remove rainwater. As part of the program to ensure that oil containment systems are to a uniformly high and acceptable standard, an overall assessment of their condition would have been undertaken resulting in upgrading or replacement as necessary. As most systems will therefore have been subject to relatively recent assessment, and if necessary upgrade/refurbishment, condition based end-of-life would not normally be considered a significant issue. However, if a major defect or damage was detected during routine inspection a full assessment, and if necessary appropriate repair or replacement, would be undertaken.

Layout of a typical drainage system for a Hydro One station is shown in Figure 23.

---

**Figure 23: Components of Drainage Systems**
2.20 Yards

Transmission station yards, when first constructed must initially be stripped, compacted, and graded. Stripping involves removal of the vegetation including roots and top soil, including all undesirable other soil elements, such as rock, boulders, organic materials, and scrap, as well as items such as bog and quicksand. After the removal of undesirable soils elements is completed, the site is graded to the final design sub-surface elevation(s). This generally involves movement of subsurface soils from some areas of the site to other site areas and occasionally the addition of extra fill, or removal of unneeded fill. Drainage, including ditches around the site would be added at this point in the process. During the process of grading the site is also compacted to ensure soils stability and bearing capability. The last stage in yard preparation is the addition of suitable toppings, such as crushed rock to ensure a high resistance cover over the ground grid.

Guidance during this process is provided by the interpretation of geotechnical tests carried out prior to the start of site works. These tests involve drilling and excavations of soils at site as well as extensive analysis of the soils to determine their suitability for inclusion in the final site subsurface.

2.21 Roads

Roads into and inside station sites are conventionally divided into two types, surfaced and un-surfaced. Both types of road are built in approximately the same manner up to the final surface layer. The sub-surface layers are specially compacted and normally special fill is brought in to ensure sufficient subsurface bearing capacity is provided. Occasionally, special geotechnical fabrics are installed below the road to ensure adequate bearing capability. Un-surfaced roads are finished with gravel to provide a drivable surface. Surfaced roads are conventionally surfaced with asphalt, or sometimes concrete.

2.22 Footings

Footings for equipment support are almost always made out of reinforced concrete. Very occasionally in locations where soils conditions are poor pile foundations are provided, with a variant of this type of foundation provided by the use of screw anchors. It is understood there are very few piled foundations, and no screw anchor foundations used within the Hydro One system. A typical footing is shown in Figure 24.

There are two basic variants for the installation of footings. One involves excavation of the entire site and then the installation of the footings at the base level, with soils installed and graded from this level. The other involves excavation into the compacted sub-grade and installation of the foundations in the sub-grade materials. Footings installed in this manner may either be excavated or they may be augured. Auguring is generally preferred on a cost basis; but both are viable methods of footing excavation. The first type of foundation installation practice is generally only used in granular soils; the second type, the excavated or augured type, is generally used in more cohesive soils, such as clay.
Footings of course must be carefully designed to match the soils in which they are placed and also they must be adequate for the ultimate loads they must carry, under extreme conditions of weather as well as electromechanical loadings. Appropriate safety factors are always applied.

Figure 24: Damaged Footing of a SF₆ Bus Duct
3.0 Stations Asset Demographics

This section provides demographics data for major power system assets that are found at Hydro One Stations excluding Protection and Control assets.

3.1 Oil Circuit Breakers - Demographics

Hydro One Inc. (Hydro One) has 2,001 Oil Circuit Breakers (OCB) in its transmission substations operating at voltages up to 230 kV. Approximately 70% of these are providing service at voltages below 50 kV, 19% at 115 kV and the remaining 10% at 230 kV. The majority of these OCB (60%) are 20 to 40 years old and about 17% are more than 40 years old as shown in Table 2. Table 2 also illustrates the demographics of OCB with respect to age (original installation or refurbishment date).

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>&lt;50 kV</th>
<th>115 kV</th>
<th>230 kV</th>
<th>Total</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Age Group</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0-10yrs</td>
<td>69</td>
<td>34</td>
<td>9</td>
<td>112</td>
<td>5.60%</td>
</tr>
<tr>
<td>11-20yrs</td>
<td>238</td>
<td>138</td>
<td>23</td>
<td>399</td>
<td>19.94%</td>
</tr>
<tr>
<td>21-30yrs</td>
<td>163</td>
<td>16</td>
<td>27</td>
<td>206</td>
<td>10.29%</td>
</tr>
<tr>
<td>31-40yrs</td>
<td>467</td>
<td>73</td>
<td>109</td>
<td>649</td>
<td>32.43%</td>
</tr>
<tr>
<td>41-50yrs</td>
<td>366</td>
<td>73</td>
<td>33</td>
<td>472</td>
<td>23.59%</td>
</tr>
<tr>
<td>&gt;50yrs</td>
<td>105</td>
<td>49</td>
<td>2</td>
<td>156</td>
<td>7.80%</td>
</tr>
<tr>
<td>Unknown</td>
<td>7</td>
<td>0</td>
<td>0</td>
<td>7</td>
<td>0.35%</td>
</tr>
<tr>
<td>Total</td>
<td>1415</td>
<td>383</td>
<td>203</td>
<td>2001</td>
<td>100.00%</td>
</tr>
<tr>
<td>(%)</td>
<td>70.71%</td>
<td>19.14%</td>
<td>10.14%</td>
<td>100.00%</td>
<td></td>
</tr>
</tbody>
</table>

Table 2: Oil Circuit Breaker Demographics

The last oil breakers were purchased in 1983, after which manufacture effectively ceased. In the 1990s, with the assistance of the original manufacturers of the OCB Hydro One began a program of “remanufacturing” some of its oldest OCB. These breakers were designated as “new” from an accounting standpoint and are the group shown as being up to 25 years old in Figure 25. Hydro One remanufactured 431 breakers of various ratings were before the program was ended and the remanufacturing facilities were closed down. Spare parts remain available from third parties but technical support from OEMs is no longer available.
3.2 SF6 Circuit Breakers - Demographics

Hydro One has 1254 SF6 free standing circuit breakers in its transmission stations operating at voltages up to 500 kV. Approximately 64% of these are providing service at voltages below 50 kV, 11% at 115 kV, 22% at 230 kV and the remaining 3% at 500 kV as shown in Table 3.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>0-10yrs</th>
<th>11-20yrs</th>
<th>21-30yrs</th>
<th>31-40yrs</th>
<th>41-50yrs</th>
<th>&gt;50yrs</th>
<th>Unknown</th>
<th>Total</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage Class</td>
<td>&lt;50 kV</td>
<td>115 kV</td>
<td>230 kV</td>
<td>500 kV</td>
<td>Total</td>
<td>(%)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0-10yrs</td>
<td>94</td>
<td>33</td>
<td>115</td>
<td>14</td>
<td>256</td>
<td>20.41%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11-20yrs</td>
<td>328</td>
<td>37</td>
<td>45</td>
<td>12</td>
<td>422</td>
<td>33.65%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>21-30yrs</td>
<td>210</td>
<td>19</td>
<td>45</td>
<td>10</td>
<td>284</td>
<td>22.65%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>31-40yrs</td>
<td>0</td>
<td>10</td>
<td>9</td>
<td>0</td>
<td>19</td>
<td>1.52%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>41-50yrs</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>0.08%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>&gt;50yrs</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unknown</td>
<td>163</td>
<td>42</td>
<td>60</td>
<td>7</td>
<td>272</td>
<td>21.69%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>796</td>
<td>141</td>
<td>274</td>
<td>43</td>
<td>1254</td>
<td>100.00%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(%)</td>
<td>63.48%</td>
<td>11.24%</td>
<td>21.85%</td>
<td>3.43%</td>
<td>100.00%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 3: SF6 Free Standing Circuit Breaker Demographics
3.3 Air Blast Circuit Breakers - Demographics

There are a total of 223 Air Blast Circuit Breakers (ABCB) on the Hydro One’ transmission system representing approximately 5% of all the circuit breakers Hydro One owns. Table 4 show the age demographics of ABCB by voltage class. As can be seen from the table, ABCB are mostly used on 230 kV systems, with more modest applications at 500 kV, 115 kV and at voltages below 50 kV. There are 192 HV (at 115 kV or above) and 31 LV ABCB installed on Hydro One’s system, mostly built between 1950 and 1982.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>&lt;50 kV</th>
<th>115 kV</th>
<th>230 kV</th>
<th>500 kV</th>
<th>Total</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-10yrs</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>11-20yrs</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>21-30yrs</td>
<td>2</td>
<td>0</td>
<td>12</td>
<td>0</td>
<td>14</td>
<td>6.28%</td>
</tr>
<tr>
<td>31-40yrs</td>
<td>0</td>
<td>2</td>
<td>60</td>
<td>50</td>
<td>112</td>
<td>50.22%</td>
</tr>
<tr>
<td>41-50yrs</td>
<td>18</td>
<td>0</td>
<td>68</td>
<td>0</td>
<td>86</td>
<td>38.57%</td>
</tr>
<tr>
<td>&gt;50yrs</td>
<td>11</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>11</td>
<td>4.93%</td>
</tr>
<tr>
<td>Unknown</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>Total</td>
<td>31</td>
<td>2</td>
<td>140</td>
<td>50</td>
<td>223</td>
<td>100.00%</td>
</tr>
<tr>
<td>(%)</td>
<td>13.90%</td>
<td>0.90%</td>
<td>62.78%</td>
<td>22.42%</td>
<td>100.00%</td>
<td></td>
</tr>
</tbody>
</table>

Table 4: Air Blast Circuit Breakers Demographics

3.4 Gas Insulated Switchgear (GIS) - Demographics

There are three 500 kV, five 230 kV and one 115 kV GIS currently in operation on the Hydro One system, with the oldest being commissioned in 1977. In addition, there are four medium voltage GIS installed on the Hydro One system, all within the past three years.

There are 55 LV (50kV<) and 109 HV SF\(_6\) circuit breakers, associated switches, buses and ancillary equipment currently installed in Hydro One gas insulated substations. A circuit breaker bay (CBB) is considered to be the 3-phase assembly of a circuit breaker, and its associated disconnects and ground switches, instrument transformers, and interconnecting buses. Circuit breakers installed on the LV GIS are all of the vacuum technology.
3.5 Metalclad Switchgear - Demographics

As tabulated in Table 5, there are 753 metalclad switchgear installations on the 13.8kV and 27.6kV systems.

<table>
<thead>
<tr>
<th>MetalClad Breaker</th>
<th>Voltage Class</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>13 kV</td>
</tr>
<tr>
<td>0-10yrs</td>
<td>36</td>
</tr>
<tr>
<td>11-20yrs</td>
<td>121</td>
</tr>
<tr>
<td>21-30yrs</td>
<td>223</td>
</tr>
<tr>
<td>31-40yrs</td>
<td>109</td>
</tr>
<tr>
<td>41-50yrs</td>
<td>44</td>
</tr>
<tr>
<td>&gt;50yrs</td>
<td>16</td>
</tr>
<tr>
<td>Unknown</td>
<td>79</td>
</tr>
<tr>
<td>Total</td>
<td>628</td>
</tr>
<tr>
<td>(%)</td>
<td>83.40%</td>
</tr>
</tbody>
</table>

Table 5: Metalclad Switchgear Demographics

Approximately 85% of the Hydro One switchgear population is operated at the 13.8 kV voltage level and the remainder is 27.6kV voltage levels. About 50% of the switchgear assemblies are over 25 years old. Expected life for metalclad switchgear is 40-50 years.

3.6 Transformer - Demographics

Hydro One owns 1,467 transmission transformers. This asset class covers a wide range of transformers, which vary in terms of voltage ratings, power ratings, functions, etc. The following functional groups are included under the transmission transformers asset class. For clarity throughout the document, these groups are consolidated to form three main functional groups.

**Group 1:**
- Autotransformers:
- Two and three winding transformers
- Phase shifting transformers
- Shunt Reactors
- Grounding transformers.

**Group 2:**
- Regulator transformers
- Grounding transformers

**Group 3:**
- Station Service Transformers
- Miscellaneous transformers.

Table 6 shows the demographics of Group 1 transformers.
Group 1 - Transformers

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>0-10yrs</th>
<th>11-20yrs</th>
<th>21-30yrs</th>
<th>31-40yrs</th>
<th>41-50yrs</th>
<th>&gt;50yrs</th>
<th># Unknown</th>
<th>Total</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Autotransformers</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>115kV</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>5</td>
<td>0</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>230kV</td>
<td>7</td>
<td>9</td>
<td>11</td>
<td>17</td>
<td>24</td>
<td>21</td>
<td>0</td>
<td>89</td>
<td></td>
</tr>
<tr>
<td>345kV</td>
<td>0</td>
<td>0</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>500kV</td>
<td>7</td>
<td>9</td>
<td>4</td>
<td>15</td>
<td>8</td>
<td>0</td>
<td>0</td>
<td>43</td>
<td></td>
</tr>
<tr>
<td>Sub-Total</td>
<td>14</td>
<td>18</td>
<td>17</td>
<td>33</td>
<td>34</td>
<td>26</td>
<td>0</td>
<td>142</td>
<td>18.6%</td>
</tr>
<tr>
<td>2-3 Winding Transformers</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>115kV</td>
<td>34</td>
<td>16</td>
<td>18</td>
<td>40</td>
<td>49</td>
<td>144</td>
<td>0</td>
<td>301</td>
<td></td>
</tr>
<tr>
<td>230kV</td>
<td>25</td>
<td>44</td>
<td>42</td>
<td>104</td>
<td>64</td>
<td>8</td>
<td>0</td>
<td>287</td>
<td></td>
</tr>
<tr>
<td>Sub-Total</td>
<td>59</td>
<td>60</td>
<td>60</td>
<td>144</td>
<td>113</td>
<td>152</td>
<td>0</td>
<td>588</td>
<td>76.9%</td>
</tr>
<tr>
<td>Phase Shifters</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>230kV regulator - 230 kV</td>
<td>0</td>
<td>2</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Sub-Total</td>
<td>0</td>
<td>2</td>
<td>0</td>
<td>2</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>5</td>
<td>0.7%</td>
</tr>
<tr>
<td>Shunt Reactors &lt;50kV shunt</td>
<td>0</td>
<td>4</td>
<td>3</td>
<td>7</td>
<td>4</td>
<td>0</td>
<td>12</td>
<td>30</td>
<td></td>
</tr>
<tr>
<td>Grand Total</td>
<td>73</td>
<td>84</td>
<td>80</td>
<td>186</td>
<td>152</td>
<td>178</td>
<td>12</td>
<td>765</td>
<td></td>
</tr>
<tr>
<td>%</td>
<td>9.5%</td>
<td>11.0%</td>
<td>10.5%</td>
<td>24.3%</td>
<td>19.9%</td>
<td>23.3%</td>
<td>1.6%</td>
<td>100.0%</td>
<td></td>
</tr>
</tbody>
</table>

Table 6: Ages and Voltage Breakdown of Group 1 Transformers

The transformers in this group are used on all voltage levels up to 500 kV but a predominant 96% are installed in the 115 kV and 230 kV systems. Not counting the # of unknown age, approximately 23.3% of the transformers in this group are over 50 years old.

Group 2 - Regulator transformers

The second group of transformers includes regulator transformers and grounding transformers. Table 7 shows the age breakdown of these transformers. Not counting the # of unknown age, a total of 54.4% of these Group 2 transformers are over 30 years old.

<table>
<thead>
<tr>
<th>Type</th>
<th>0-10yrs</th>
<th>11-20yrs</th>
<th>21-30yrs</th>
<th>31-40yrs</th>
<th>41-50yrs</th>
<th>&gt;50yrs</th>
<th># Unknown</th>
<th>Total</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulators</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>2</td>
<td>2</td>
<td>13</td>
<td>0</td>
<td>17</td>
<td>10.76%</td>
</tr>
<tr>
<td>Grounding Transformers</td>
<td>2</td>
<td>15</td>
<td>25</td>
<td>39</td>
<td>18</td>
<td>12</td>
<td>30</td>
<td>141</td>
<td>89.24%</td>
</tr>
<tr>
<td>Total</td>
<td>2</td>
<td>15</td>
<td>25</td>
<td>41</td>
<td>20</td>
<td>25</td>
<td>30</td>
<td>158</td>
<td>100.00%</td>
</tr>
<tr>
<td>%</td>
<td>1.27%</td>
<td>9.49%</td>
<td>15.82%</td>
<td>25.95%</td>
<td>12.66%</td>
<td>15.82%</td>
<td>18.99%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 7: Age Breakdowns of Group 2 Transformers

Group 3 - Station Service Transformers

Station service transformers and miscellaneous transformers form the third group of the transmission transformer asset class. Table 8 shows the age breakdown of these transformers. As seen from the table, not counting the number of unknown age, 54% of this group consists of
transformers over 30 years old, however, a significant number of station service transformers do not have age data associated with them.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>0-10yrs</th>
<th>11-20yrs</th>
<th>21-30yrs</th>
<th>31-40yrs</th>
<th>41-50yrs</th>
<th>&gt;50yrs</th>
<th># Unknown</th>
<th>Total</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Station Service</td>
<td>25</td>
<td>73</td>
<td>64</td>
<td>137</td>
<td>91</td>
<td>66</td>
<td>88</td>
<td>544</td>
<td>100.00%</td>
</tr>
<tr>
<td>Misc.</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>Total</td>
<td>25</td>
<td>73</td>
<td>64</td>
<td>137</td>
<td>91</td>
<td>66</td>
<td>88</td>
<td>544</td>
<td>100.00%</td>
</tr>
<tr>
<td>%</td>
<td>4.60%</td>
<td>13.42%</td>
<td>11.76%</td>
<td>25.18%</td>
<td>16.73%</td>
<td>12.13%</td>
<td>16.18%</td>
<td>100.00%</td>
<td></td>
</tr>
</tbody>
</table>

Table 8: Age Breakdowns of Group 3 Transformers

The above demographic data are displayed graphically and in more detail in Figure 26 to 29.
Figure 26: Autotransformer Demographics

Figure 27: 2-3 Winding 115 and 230 kV Transformer Demographics
Figure 28: 2-3 Winding 115 and 230 kV Transformer Demographics

Figure 29: 2-3 Winding 230 kV Transformer Demographics
3.7 HV/LV SWITCH DEMOGRAPHICS

Hydro One currently manages 14,329 switches of different voltage classes and ages as shown in Table 9. About 55% of these are LV switches and the remaining 45% are HV switches. Approximately 29% of the switches are more than 40 years old. However, some caution has to be exercised in the interpretation of the data analysis because of the very poor demographic switch data in the Hydro One databases.

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>LV (%)</th>
<th>HV (%)</th>
<th>Totals (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13.8 kV</td>
<td>10.91%</td>
<td>19.83%</td>
<td>5.39%</td>
</tr>
<tr>
<td>27.6 kV</td>
<td>26.86%</td>
<td>20.83%</td>
<td>10.00%</td>
</tr>
<tr>
<td>44 kV</td>
<td>16.16%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>115 kV</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>230 kV</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>500 kV</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>100.00%</td>
<td>100.00%</td>
<td>100.00%</td>
</tr>
</tbody>
</table>

Table 9: HV/LV Switch Demographics

3.8 High Voltage Instrument Transformers (HVITs) - Demographics

Hydro One currently manages 4297 HVITs. Table 10 shows the breakdown of all HVITs with respect to four nominal voltage classes. As can be seen from the table, HVITs are used throughout the transmission system, but the majority (approximately 59%) are used at 230 kV.

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>69 kV (%)</th>
<th>115 kV (%)</th>
<th>230 kV (%)</th>
<th>500 kV (%)</th>
<th>Total (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-10yrs</td>
<td>0</td>
<td>246</td>
<td>592</td>
<td>31</td>
<td>869</td>
</tr>
<tr>
<td>11-20yrs</td>
<td>0</td>
<td>553</td>
<td>506</td>
<td>59</td>
<td>1118</td>
</tr>
<tr>
<td>21-30yrs</td>
<td>0</td>
<td>91</td>
<td>193</td>
<td>52</td>
<td>336</td>
</tr>
<tr>
<td>31-40yrs</td>
<td>0</td>
<td>112</td>
<td>546</td>
<td>78</td>
<td>736</td>
</tr>
<tr>
<td>&gt;41yrs</td>
<td>0</td>
<td>159</td>
<td>178</td>
<td>3</td>
<td>340</td>
</tr>
<tr>
<td>Unknown</td>
<td>0</td>
<td>139</td>
<td>519</td>
<td>240</td>
<td>898</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>0</td>
<td>1300</td>
<td>2534</td>
<td>463</td>
<td>4297</td>
</tr>
</tbody>
</table>

Table 10: HVIT Demographics (All Types)

Table 10 also illustrates the age demographics of HVITs. This table shows, about 29% of the total population is older than 30 years.
The HVITs are categorized into the following sub-categories based on insulation medium and type:

a) Oil filled Current Transformer (Oil CT)
b) Oil filled Capacitive Voltage Transformer (Oil CVT)
c) Oil filled Voltage (Voltage) Transformer (Oil VT)
d) SF₆ Insulated Current Transformer SF₆ CT)
e) Other or undefined

Table 11 shows the breakdown of HVIT Oil CTs with respect to three nominal voltage classes. This table shows that Oil CTs are used in Hydro One’s transmission system at ≥ 115 kV and the majority of these (approximately 82%) are used at 230 kV.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>115 kV</th>
<th>230 kV</th>
<th>500 kV</th>
<th>Total</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-10yrs</td>
<td>10</td>
<td>24</td>
<td>3</td>
<td>37</td>
<td>2.78%</td>
</tr>
<tr>
<td>11-20yrs</td>
<td>3</td>
<td>257</td>
<td>6</td>
<td>266</td>
<td>20.02%</td>
</tr>
<tr>
<td>21-30yrs</td>
<td>27</td>
<td>82</td>
<td>6</td>
<td>115</td>
<td>8.65%</td>
</tr>
<tr>
<td>31-40yrs</td>
<td>4</td>
<td>389</td>
<td>5</td>
<td>398</td>
<td>29.95%</td>
</tr>
<tr>
<td>&gt;41yrs</td>
<td>12</td>
<td>65</td>
<td>0</td>
<td>77</td>
<td>5.79%</td>
</tr>
<tr>
<td>Unknown</td>
<td>12</td>
<td>276</td>
<td>148</td>
<td>436</td>
<td>32.81%</td>
</tr>
<tr>
<td>Total</td>
<td>68</td>
<td>1093</td>
<td>168</td>
<td>1329</td>
<td>100.00%</td>
</tr>
</tbody>
</table>

Table 11: HVIT, Oil CT Demographics

Table 12 shows the breakdown of HVIT Oil CVTs with respect to three nominal voltage classes. This table shows that Oil CVTs are used in Hydro One’s transmission system at ≥ 115 kV and the majority of these (approximately 60%) are at 230 kV.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>115 kV</th>
<th>230 kV</th>
<th>500 kV</th>
<th>Total</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-10yrs</td>
<td>219</td>
<td>500</td>
<td>25</td>
<td>744</td>
<td>35.33%</td>
</tr>
<tr>
<td>11-20yrs</td>
<td>256</td>
<td>214</td>
<td>41</td>
<td>511</td>
<td>24.26%</td>
</tr>
<tr>
<td>21-30yrs</td>
<td>9</td>
<td>74</td>
<td>42</td>
<td>125</td>
<td>5.94%</td>
</tr>
<tr>
<td>31-40yrs</td>
<td>18</td>
<td>138</td>
<td>67</td>
<td>223</td>
<td>10.59%</td>
</tr>
<tr>
<td>&gt;41yrs</td>
<td>32</td>
<td>105</td>
<td>3</td>
<td>140</td>
<td>6.65%</td>
</tr>
<tr>
<td>Unknown</td>
<td>80</td>
<td>232</td>
<td>51</td>
<td>363</td>
<td>17.24%</td>
</tr>
<tr>
<td>Total</td>
<td>614</td>
<td>1263</td>
<td>229</td>
<td>2106</td>
<td>100.00%</td>
</tr>
</tbody>
</table>

Table 12: HVIT, Oil CVT Demographics
Table 13 shows the breakdown of HVIT Oil VTs with respect to four nominal voltage classes. This table shows that Oil VTs are used throughout the Hydro One’ transmission system and the majority of these (approximately 67%) are used at 115 kV.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>69 kV</th>
<th>115 kV</th>
<th>230 kV</th>
<th>500 kV</th>
<th>Total</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-10yrs</td>
<td>0</td>
<td>50</td>
<td>51</td>
<td>2</td>
<td>103</td>
<td>12.58%</td>
</tr>
<tr>
<td>11-20yrs</td>
<td>0</td>
<td>304</td>
<td>26</td>
<td>0</td>
<td>330</td>
<td>40.29%</td>
</tr>
<tr>
<td>21-30yrs</td>
<td>0</td>
<td>57</td>
<td>34</td>
<td>0</td>
<td>91</td>
<td>11.11%</td>
</tr>
<tr>
<td>31-40yrs</td>
<td>0</td>
<td>100</td>
<td>5</td>
<td>0</td>
<td>105</td>
<td>12.82%</td>
</tr>
<tr>
<td>&gt;41yrs</td>
<td>1</td>
<td>117</td>
<td>8</td>
<td>0</td>
<td>126</td>
<td>15.38%</td>
</tr>
<tr>
<td>Unknown</td>
<td>0</td>
<td>56</td>
<td>8</td>
<td>0</td>
<td>64</td>
<td>7.81%</td>
</tr>
<tr>
<td>Total</td>
<td>1</td>
<td>684</td>
<td>132</td>
<td>2</td>
<td>819</td>
<td>100.00%</td>
</tr>
</tbody>
</table>

Table 13: HVIT, Oil VT Demographics

Table 13 also illustrates the age demographics of Oil VTs. This table shows that about 4% of the total population are greater than 30 years old and that the age of approximately 43% of these is unknown.

Table 14 shows the breakdown of HVIT SF₆ CTs with respect to three nominal voltage classes. This table shows that SF₆ CTs are normally used at 230 kV and 500 kV.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>115 kV</th>
<th>230 kV</th>
<th>500 kV</th>
<th>Total</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-10yrs</td>
<td>0</td>
<td>3</td>
<td>0</td>
<td>3</td>
<td>6.82%</td>
</tr>
<tr>
<td>11-20yrs</td>
<td>0</td>
<td>9</td>
<td>2</td>
<td>11</td>
<td>25.00%</td>
</tr>
<tr>
<td>21-30yrs</td>
<td>0</td>
<td>3</td>
<td>0</td>
<td>3</td>
<td>6.82%</td>
</tr>
<tr>
<td>31-40yrs</td>
<td>0</td>
<td>14</td>
<td>0</td>
<td>14</td>
<td>31.82%</td>
</tr>
<tr>
<td>&gt;41yrs</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>Unknown</td>
<td>0</td>
<td>3</td>
<td>10</td>
<td>13</td>
<td>29.55%</td>
</tr>
<tr>
<td>Total</td>
<td>0</td>
<td>32</td>
<td>12</td>
<td>44</td>
<td>100.00%</td>
</tr>
</tbody>
</table>

Table 14: HVIT, SF₆ CT Demographics
3.9 Station Insulators - Demographics

Combining the results of Hydro One surveys with known quantities of other apparatus which are supported by insulators, such as, switches, capacitor banks and reactors, it is possible to estimate insulator demographic data. The current population of Hydro One station insulators (stacks) is estimated to exceed 170,000, with over 90,000 being cap & pin, and over 78,000 being post type. In addition to these, there are also in excess of 48,000 strain insulator strings within stations. Approximately 99% of station insulators (strain, cap & pin, post) are porcelain, with the remaining 1% made of glass or a polymeric material. About 25% of strain and cap & pin insulators in the stations are 50 years of age or greater, and are considered to at the end of their design life.

As shown in Table 15 it can be seen that the total number of rigid insulators (Cap & Pin and Post) is about 170,000. Approximately 63% of these are installed on disconnect switches, about 2% support capacitors and other apparatus and with the remaining 35% being applied as bus supports.

<table>
<thead>
<tr>
<th>Insulator Type</th>
<th>Total</th>
<th>&lt; 50 Years</th>
<th>&gt; 50 Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Station Post</td>
<td>78134</td>
<td>60000</td>
<td>18134</td>
</tr>
<tr>
<td>Station Cap &amp; Pin</td>
<td>91866</td>
<td>70866</td>
<td>21000</td>
</tr>
<tr>
<td>Station String</td>
<td>48000</td>
<td>35000</td>
<td>13000</td>
</tr>
<tr>
<td>Station Other</td>
<td>2000</td>
<td>1000</td>
<td>1000</td>
</tr>
<tr>
<td>Total</td>
<td>220000</td>
<td>166866</td>
<td>53134</td>
</tr>
</tbody>
</table>

Table 15: Estimated Number and Age of Station Insulators

3.10 Station Cables and Potheads - Demographics

Transformer secondary cable circuits constitute the largest segment of the cable population.

About 73% of these cables are of paper insulated lead covered (PILC) construction with the remaining 27% being cross-linked polyethylene (XLPE). About 4,500 potheads and terminators are applied on these transformer secondary cables. The total number of cables is estimated to be 2,256 and assuming an average length of each cable as 80 m, brings the total length of the cables to be approximately 180 km. Demographics data was available for approximately 72% of cables, providing a basis for a good age estimate of overall cable population.

Cables used to connect the static capacitor banks to the switchgear constitute the next largest segment of the cable population. These cables range in size from 350 kcmil to 3000 kcmil with the average being in the 1000 kcmil size range. It is estimated that there is over 25 km of single conductor cable used to connect the Hydro One capacitor banks to the associated switchgear. The number of associated potheads and terminators is estimated at about 1000. The remainder of the Hydro One cable population comprises of relatively small sized, 2/0 to 500 kcmil range, three conductor cables supplying station service and grounding transformers.
3.11 Capacitor Banks - Demographics

Hydro One currently manages 354 capacitors banks located in transmission stations. Table 16 shows the capacitors demographics with respect to three nominal voltage classes. As can be seen from the table, approximately 84% of capacitors are used at voltages under 50 kV.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>0-10 yrs</th>
<th>11-20 yrs</th>
<th>21-30 yrs</th>
<th>31-40 yrs</th>
<th>41-50 yrs</th>
<th>&gt;50 yrs</th>
<th>Unknown</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>&lt; 50 kV</td>
<td>115 kV</td>
<td>230 kV</td>
<td>Total</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0-10 yrs</td>
<td>66</td>
<td>13</td>
<td>22</td>
<td>101</td>
<td>28.53%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11-20 yrs</td>
<td>161</td>
<td>6</td>
<td>7</td>
<td>174</td>
<td>49.15%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>21-30 yrs</td>
<td>23</td>
<td>2</td>
<td>3</td>
<td>28</td>
<td>7.91%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>31-40 yrs</td>
<td>1</td>
<td>1</td>
<td>0</td>
<td>2</td>
<td>0.56%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>41-50 yrs</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>0.28%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&gt;50 yrs</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unknown</td>
<td>45</td>
<td>2</td>
<td>1</td>
<td>48</td>
<td>13.56%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>297</td>
<td>24</td>
<td>33</td>
<td>354</td>
<td>100.00%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| (%)       | 83.90%  | 6.78%     | 9.32%     | 100.00%   |

Table 16: Capacitor Demographics
3.12 HIGH PRESSURE AIR SYSTEM - DEMOGRAPHICS

Hydro One currently manages 25 HPA systems, including 79 compressors, 70 dryers, and 377 air receivers for HPA systems.

Table 17 shows the age demographics of compressors and dryers. As is shown, approximately 47% of the compressors and 38% of the dryers are over 30 years old. Interesting, only 3 compressors and 2 dryers were installed during the period of 11 to 20 years ago.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>Compressor (%)</th>
<th>Dryer (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-10yrs</td>
<td>2, 2.53%</td>
<td>3, 4.29%</td>
</tr>
<tr>
<td>11-20yrs</td>
<td>6, 7.59%</td>
<td>16, 22.86%</td>
</tr>
<tr>
<td>21-30yrs</td>
<td>3, 3.80%</td>
<td>0, 0.00%</td>
</tr>
<tr>
<td>31-40yrs</td>
<td>29, 36.71%</td>
<td>23, 32.86%</td>
</tr>
<tr>
<td>41-50yrs</td>
<td>15, 18.99%</td>
<td>11, 15.71%</td>
</tr>
<tr>
<td>&gt;50yrs</td>
<td>0, 0.00%</td>
<td>0, 0.00%</td>
</tr>
<tr>
<td>unknown</td>
<td>24, 30.38%</td>
<td>17, 24.29%</td>
</tr>
<tr>
<td>Total</td>
<td>79, 100.00%</td>
<td>70, 100.00%</td>
</tr>
</tbody>
</table>

Table 17: Compressor and Dryer Demographics

3.13 Batteries and Chargers - Demographics

Hydro One currently manages a total of 660 transmission station and communications (Telecom) batteries and a total of 672 battery chargers. As shown in Table 18 approximately 87% of the total transmission batteries and approximately 60% of the chargers were installed in the last twenty years.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>All Batteries</th>
<th>Chargers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>(%)</td>
<td>(%)</td>
</tr>
<tr>
<td>0-10 yrs</td>
<td>341, 51.67%</td>
<td>232, 34.52%</td>
</tr>
<tr>
<td>11-20 yrs</td>
<td>233, 35.30%</td>
<td>169, 25.15%</td>
</tr>
<tr>
<td>21-30 yrs</td>
<td>69, 10.45%</td>
<td>96, 14.29%</td>
</tr>
<tr>
<td>31-40 yrs</td>
<td>2, 0.30%</td>
<td>110, 16.37%</td>
</tr>
<tr>
<td>41-50 yrs</td>
<td>0, 0.00%</td>
<td>27, 4.02%</td>
</tr>
<tr>
<td>&gt;50 yrs</td>
<td>0, 0.00%</td>
<td>0, 0.00%</td>
</tr>
<tr>
<td>Unknown</td>
<td>15, 2.27%</td>
<td>38, 5.65%</td>
</tr>
<tr>
<td>Total</td>
<td>660, 100.00%</td>
<td>672, 100.00%</td>
</tr>
</tbody>
</table>

Table 18: Transmission Batteries and Chargers Demographics
3.14 Station Grounding Systems - Demographics

Hydro One Hydro One Inc (Hydro One) currently manages 281 transmission stations, all of which have their own grounding systems. Approximately 50% of the grounding systems were installed/upgraded in the last 50 years, while only 16% were installed/upgraded within the last 30 years, as shown in Table 19.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>Transmission Station Grounding Systems</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-10yrs</td>
<td>12</td>
<td>4.27%</td>
</tr>
<tr>
<td>11-20yrs</td>
<td>16</td>
<td>5.69%</td>
</tr>
<tr>
<td>21-30yrs</td>
<td>17</td>
<td>6.05%</td>
</tr>
<tr>
<td>31-40yrs</td>
<td>46</td>
<td>16.37%</td>
</tr>
<tr>
<td>41-50yrs</td>
<td>50</td>
<td>17.79%</td>
</tr>
<tr>
<td>&gt;50yrs</td>
<td>134</td>
<td>47.69%</td>
</tr>
<tr>
<td>Unknown</td>
<td>6</td>
<td>2.14%</td>
</tr>
<tr>
<td>Total</td>
<td>281</td>
<td>100.00%</td>
</tr>
</tbody>
</table>

Table 19: Transmission Station Grounding System Demographics

3.15 AC/DC Station Service Equipment - Demographics

Hydro one currently manages AC and DC station service systems at each transmission station. Only limited demographic data is available on certain key components such as the station service transformers and transfer switches.

3.16 Station Buildings - Demographics

Table 20 shows the geographical breakdown of transmission station buildings. As is shown, approximately 74% of the total population are in the southern region of the Hydro One system.

<table>
<thead>
<tr>
<th>Building Type</th>
<th>Number of Buildings</th>
<th>Northern</th>
<th>Southern</th>
<th>Unknown</th>
<th>Total</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Control Building</td>
<td></td>
<td>72</td>
<td>345</td>
<td>31</td>
<td>448</td>
<td>49.1</td>
</tr>
<tr>
<td>Auxiliary Systems Buildings</td>
<td></td>
<td>32</td>
<td>112</td>
<td>0</td>
<td>144</td>
<td>15.8</td>
</tr>
<tr>
<td>Occupied Buildings</td>
<td></td>
<td>40</td>
<td>123</td>
<td>0</td>
<td>163</td>
<td>17.9</td>
</tr>
<tr>
<td>Ancillary Buildings</td>
<td></td>
<td>60</td>
<td>97</td>
<td>0</td>
<td>157</td>
<td>17.2</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>204</td>
<td>677</td>
<td>31</td>
<td>912</td>
<td>100.0</td>
</tr>
</tbody>
</table>

Table 20: Regional Breakdown of Transmission Buildings
4.0 Station Asset Performance

This section provides performance data for major power system assets that are found at Hydro One Stations excluding Protection and Control assets.

4.1 Circuit Breaker Performance

Hydro One keeps outage frequency and outage duration records for its HV circuit breakers. The trends for forced outage frequency are improving slightly based on the data over the period 2003-2009. However average forced outage frequency rates over the period remain higher than the CEA all-Canada average.

Figures 30, 31, 32 and 33 show the frequency of outages of Low Voltage, 115 kV, 230 kV and 500 kV breakers compared to the CEA all-Canada Average. In the figures (1) represents first half of year and (2) represents second half of year.

Figure 30: Frequency of Low Voltage Breaker Outages
115 kV Circuit Breakers

Figure 31: Frequency of 115 kV Breaker Outages

230 kV Circuit Breakers

Figure 32: Frequency of 230 kV Breaker Outages
Figures 34 35, 36 and 37 show the unavailability Low Voltage, 115 kV, 230 kV and 500 kV breakers due to forced outages compared to the CEA all-Canada Average. In the figures (1) represents first half of year and (2) represents second half of year.
Low Voltage Circuit Breakers

Unavailability due to Forced Outages

Figure 34: Unavailability of Low Voltage Breakers Due to Forced Outages

115 kV Circuit Breakers

Unavailability due to Forced Outages

Figure 35: Unavailability of 115 kV Breakers Due to Forced Outages
Figure 36: Unavailability of 230 kV Breakers Due to Forced Outages

Figure 37: Unavailability of 500 kV Breakers Due to Forced Outages
4.1.1 Oil Circuit Breakers - Performance

Hydro One keeps outage frequency and outage duration records for its HV circuit oil breakers. The trends for forced outage frequency are improving slightly based on the data over the period 2003-2009. However average forced outage frequency rates over the period remain higher than the CEA all-Canada average. Nevertheless oil breakers remain the best performing class of breakers on the Hydro One system.

4.1.2 SF$_6$ Circuit Breaker - Performance

There is clear evidence from an increasing trend in forced outages and increasing maintenance costs, of deteriorating performance of the early vintage SF6 breakers over the last 5 years. These failure prone SF6 breakers represent less than 10% of the HV breaker population about 44% of the worst performing HV breakers (based on forced outage frequency) are SF6 CBs.

A large proportion (about 30%) of the SF6 breaker population is applied for the most onerous, special purpose duties, such as reactor and capacitor bank switching, some involving several hundred operations per year thus accelerating the mechanical and electrical wear out of the breaker. The complex control and operating mechanisms installed in almost all of these early vintage breakers resulted in increased operating problems and significant maintenance and refurbishment expenditures. Most of these very poor performing breakers have reached or surpassed their mechanical design life of 2000 switching operations.

Heaters are required on many of these breakers to prevent liquefaction of the SF6 gas at the low temperatures prevailing in Ontario. Heaters and control equipment, contactors, thermostats, and wiring degrade at an accelerated rate under these extreme conditions.

Gas seals leak at an increased level at low temperature putting increased pressure associated apparatus. Generally, earlier models have more problems than later ones, since modern equipment has improved seal and valve designs.

4.1.3 Air Blast Circuit Breakers - Performance

ABCBs are no longer manufactured, and as of 2010, are not supported with parts or technical expertise by two of the original three manufacturers. It is expected that the third vendor will cease technical support in the near future. Replacement parts, if they can be obtained are prohibitively expensive.

The utility industry has identified degradation of gaskets, seals, and valves as the critical long-term issues related to EOL of ABCBs. Experience has shown that gasket and seal deterioration is time-related with major performance problems being experienced when gaskets and seals are 20-25 years old. To deal with these in the past Hydro One has undertaken a major rebuild of each ABCB after approximately 20-25 years of service. The last rebuild program was completed in
There is clear evidence from forced outage data and increasing maintenance costs, of poor ABCB performance:

- The 5-year average forced outage frequency for Hydro One 230kV ABCBs is 0.39 occurrences per breaker per year.
- The 5-year average forced outage frequency for Hydro One 230kV ABCBs is 2.6 times the all-Canada average for 230 kV breakers.

### 4.1.4 Gas Insulated Switchgear (GIS) - Performance

Early GIS designs experienced many problems and failures. Over the past ten years many of the more failure prone designs have either been replaced or refurbished, however the transmission system still contains a significant number, representing about 60% of the total SF6 breaker population, of these early designs.

The initial high voltage GIS installations consisted typically of first generation European sourced components which in most cases were mechanically complex and relatively unproven for the operational duties encountered on the system, particularly at the then higher than standard operating voltages and short circuit interrupting requirements. As with all new developments, there was a relatively high early life failure rate, due primarily to prototype design problems and manufacturing /site assembly deficiencies. Failure rates and sustainment costs over the first five years of operation were in some cases five times higher than comparably rated, conventional air insulated substations. In addition, the complex hydraulic and other operating mechanisms installed in almost all of the 1970’s and 1980’s vintage GIS circuit breakers resulted in operating problems and significant sustainment expenditures.

Hydro One has now replaced one of the poorest performers, which was a double-pressure design manufactured in the mid 1970s and early 1980s and supplied by ITE (USA) who are no longer in business. Recent improvements in the single pressure design have resulted in relatively simple, low energy and more reliable operating mechanisms.

Apart from the circuit breakers, many of the other GIS components performed poorly; primarily disconnect switches solid epoxy cone insulators, SF6-air bushings and instrument transformers. GIS disconnect switches have turned out to be very critical components of a GIS, second only in importance to the circuit breakers. The purpose of the disconnect switch is to provide safe electrical isolation of associated circuit breakers, buses and line exits during maintenance activities as well as during normal service. Disconnect switches whether in AIS or GIS have very little rated interrupting capability because they are only opened off-load, i.e. the associated breaker is opened first. GIS disconnects operated reasonably well at 138 and 230 kV levels but performance at 500 kV was very poor. After many years of problems, a new standard and test procedure was developed in the early 1990s to eliminate this issue. For the more problematic 500 kV GIS disconnects placed in-service in the late 1980’s, measures such as operating
restrictions or field modification of contact geometry and shielding, have been employed to mitigate the risk of failures.

Metal enclosed, concentric, SF₆ insulated buses are used to interconnect other live GIS components such as circuit breakers, disconnect switches and interfaces with overhead lines, cables and transformers. Within the bus, aluminum conductors are supported on epoxy resin insulators. About 30% of the failures which have occurred since the late 1970s have been on these epoxy resin insulators. The current failure rate is considerably lower and Hydro One has developed diagnostics and monitoring procedures to detect potential failures. Figure 38 shows the number of 500 kV GIS failures over the last 30 years.

Figure 38: 500kV GIS failures per year

Failure rates and sustainment costs over the first five years of operation were in some cases several times higher than comparably rated, conventional air insulated substations. A combination of design improvements, field modifications and upgrades and more recently replacement by modern technology at one site has resulted in a significant improvement, bringing the failure rate more in line with conventional equipment.

The fact that failure rates increase as the voltage level increases has been borne out by many studies and by individual users experience, including that of Hydro One, over the past 30 or more years. The Hydro One population of 500 kV GIS has experienced a higher than expected number of major failures over its lifetime. The 550 kV GIS major failure rate, was extraordinarily high over the first five years of service and only dropped to about 12% in the early 1990’s. As teething problems diminished and corrective action was taken on a number of inherent design defects, the failure frequency has tended towards the global average of about 3 – 5% for this voltage class. There has been only one major failure on the 550 kV GIS family installed in the 1992/3 period, indicating the efficacy of the design and quality improvements implemented in
the late 1980s. The 500kV GIS population has been stable since 1994 and failure rates on average are comparable with the global average. Similarly 230kV failure rates are comparable with the global average

However, lingering problems persist at several sites, the most significant being the Merivale 230kV GIS which still retains failure prone outdoor ITE bus and line terminations having a high leakage rate to atmosphere.

**4.1.5 Metalclad Switchgear - Performance**

Major failure rates for Hydro One Inc. medium voltage conventional metalclad switchgear assemblies, comprising about 1200 cells are estimated to average about 0.0015 per cell-year over the past 10 years, translating to an average of 1.8 major failures per year. However there is no formal Hydro One process for recording the performance of low voltage circuit breakers (including metalclad switchgear)
4.2 Transformers - Performance:

Hydro One keeps outage frequency and outage duration records for its HV transformers.

Figures 39, 40 and 41 show the frequency of outages of 115 kV, 230 kV and 500 kV transformers compared to the CEA all-Canada Average. In the figures (1) represents first half of year and (2) represents second half of year.

Figure 39: Frequency of 115 kV Voltage Transformer Outages
Figure 40: Frequency of 230 kV Voltage Transformer Outages

Figure 41: Frequency of 500 kV Voltage Transformer Outages
Figures 42, 43 and 44 show the unavailability Low Voltage, 115 kV, 230 kV and 500 kV transformers due to forced outages compared to the CEA all-Canada Average. In the figures (1) represents first half of year and (2) represents second half of year.

**Figure 42: Unavailability of 115 kV Transformers Due to Forced Outages**
Figure 43: Unavailability of 230 kV Transformers Due to Forced Outages

Figure 44: Unavailability of 500 kV Transformers Due to Forced Outages
All transformers performed worse than other CEA jurisdictions in frequency and 500 kV in unavailability. It is notable that H1N’s 500 kV transformers performed many folds worse than both CEA All-Canada average performance measures.

4.3 HV/LV Switch - Performance

It is highly unusual for a disconnect switch to fail in the closed position. Switch deterioration is typically detected when a switch is called upon to operate to isolate or reconnect the device (circuit breaker, line, etc) with which it is associated. Hydro One typically experiences between 40 to 60 forced outages of other equipment per year as a result of switch defects. About 90% of switch defects do not result in an outage, because the switch can be immediately repaired or bypassed.

4.4 HVIT - Performance

Capacitive Voltage Transformers (CVTs) have some inherent design weaknesses, which relate to the high probability of resonant circuits being formed between the capacitive and inductive components of the VT. This propensity to resonance can be increased through interaction with external secondary circuits. CVTs comprise capacitors connected in series and are sensitive to overvoltages. Failure of one of the series units will impose higher than designed voltages on the remaining units leading to accelerated aging and destruction of the entire CVT. A voltage increase also exposes the connected metering and protection system to overvoltages which can result in equipment failure.

There are some significant differences between power transformers and oil filled instrument transformers with respect to degradation, failure and end-of-life. The design of instrument transformers is more complex and less conservative than with large power transformers. Consequently, the dielectric and thermal stresses on the insulation tend to be greater and degradation of the insulation can occur more rapidly. The overall result of this is that for HVITs reliability tends to be poorer and lifetime shorter than for large power transformers.

The most significant failure mode of instrument transformers is internal dielectric breakdown. These failure rates are higher than for power transformers and some patterns of failure related to specific types of equipment have emerged.

4.5 Station Insulators - Performance

Most of the data required for assessing the condition of insulators is being collected via maintenance activities. This is the most cost effective and practical method for collecting asset condition information. Hydro One has also carried out a detailed inventory and condition survey of its insulators at a cross-section (48 out of 281) substations in the province to provide a reliable and consistent basis for the ongoing management and replacement of insulators. A review of
over 140 equipment trouble reports in 2003 indicated that 43% of the troubles were found during station inspection and 20% during routine maintenance for a total of 63% found during planned maintenance or inspections. Over 20% were found during routine switching of equipment in or out of service which imposed added safety risk to personnel. Only 15% of the reports indicated that a safety problem was created by the failure.

Porcelain strain insulators within the station are usually in strings consisting of between 5 and 20 individual units. The insulator string can continue to be functional with a number of cracked units. End-of-life for a string of insulators is normally defined by a given number of cracked units.

4.6 Capacitor Bank - Performance

Capacitor banks are a composite asset consisting of capacitors, fuses, insulators and the support structure. Inrush current limiting reactors are also mounted on many of the Hydro One banks, especially for back-to-back configurations. As these are all essentially static devices, their maintenance requirements are minimal and are usually confined to visual inspection and other non-invasive checks such as infrared surveys.

External corrosion of the can at the bushing and other weldment locations are relatively common, even on the current designs of capacitors. This usually leads to leakage of the dielectric fluid and ultimately to can failure. In the recent past such failures have occurred on batches supplied by certain manufacturers, leading to accelerated EOL.

Internal degradation of fuses and capacitors can occur, primarily as a result of failure of seals and ingress of moisture. Detection of such degradation is normally carried out by visual inspection looking for signs of leakage and any abnormal heating effects. Internal degradation is also caused by operation at excessive steady state and transient voltages leading to dielectric failure. Transient overvoltages can be caused by the restriking of circuit breakers (e.g. bulk oil circuit breakers) still being used for the switching duty.

For insulators, internal degradation processes can occur, however, they are extremely difficult to detect. Assessment is normally limited to visual inspection to detect cracked insulators. The more reliable station post insulators have been applied on all capacitor banks for the past 20 or more years. The support structure will deteriorate primarily as a result of interaction with the environment due to corrosion. This can also be effectively assessed by visual inspection.

4.7 High Pressure Air - Performance

The quality of the air supplied by the HPA system is vital for the safe and effective operation of ABCBs. It is essential that contamination and moisture levels in the air be kept within very tight limits. If this is not the case serious deterioration and ultimately catastrophic failure of the circuit breaker may occur.
In most applications, air blast circuit breakers operate infrequently. In these cases the compressor is only called upon rarely for short bursts of activity to top up the stored air pressure. However, most of the compressor run time is not for breaker operation, but for making up air lost due to leaks. These leaks are usually associated with the breakers or with the isolating valves especially during long periods of cold weather or significant temperature swings. As with other mechanical devices with many moving parts, the degradation of a compressor is expected to be related to the number of hours of operation. Corrosion, wear and deterioration of internal components such as valves and seals are the most significant degradation processes. These can be addressed by regular inspections, minor overhauls and occasional major overhauls, if considered cost effective.

Another specific issue for HPA systems is that some components are classified as pressure vessels. In such cases they are subject to specific testing and regulation in accordance with pressure vessel legislation. The costs associated with fulfilling these requirements in a deteriorating system may give rise to an overall decision to replace the system.

Hydro One has well developed detailed maintenance procedures for HPA systems with a separate set of inspections and tests for the compressor, the dryer, air receivers, piping and condensate collection systems. Particular attention is paid to the quality of the air supplied, with frequent measurement (or on-line monitoring) of moisture levels. This process ensures the effective performance of the systems.

Those parts of the HPA systems which are covered by the Boilers and Pressure Vessels Act are subject to 3-year testing and approval in accordance with The Technical Standards and Safety Authority (TSSA) registration requirements.

4.8 Battery and Charger - Performance

Condition information for all batteries and chargers comes from maintenance activities. For batteries and chargers the maintenance cycle, depending on the activity is from 3 months to 5 years.

Effective battery life tends to be much shorter than many of the major components in a station. For traditional wet batteries, most electric utilities report a typical lifetime of 15 - 20 years and for the more modern sealed batteries, lifetimes are half of this.

The deterioration of a battery from an apparently healthy condition to a functional failure can be rapid. This makes condition assessment very difficult. However, careful inspection and testing of individual cells often enables the identification of high risk units in the short term.

It is well understood in the utility industry that regular inspection and maintenance of batteries and battery chargers is necessary. In most cases the explicit reason for carrying out regular maintenance inspection is to detect minor defects and rectify them. However, critical examination of trends in maintenance records can give an early warning of potential failures.
Despite the regular and frequent maintenance and inspection of battery systems, failures in service occasionally occur.

Although battery deterioration is difficult to detect, any changes in the electrical characteristics or observation of significant internal damage can be used as sensitive measures of impending failure. Batteries consist of multiple individual cells. While the significant deterioration/failure of an individual cell may be an isolated incident, detection of deterioration in a number of cells in a battery is usually the precursor to widespread failure and functional failure of the total battery.

Because batteries have relatively short lifetimes (<20 years), there is a need for continuous replacement. Utilizing information available from regular maintenance and inspection programs and responding to battery alarms results in a high overall reliability for batteries.

Battery chargers are also critical to the satisfactory performance of the whole battery system. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the batteries themselves (35-40 years). Nevertheless, problems do occur. As with other electronic devices, it is difficult to detect deterioration prior to failure. It is normal practice during the regular maintenance and inspection process to check the functionality of the battery chargers, in particular the charging rates. Where any functional failures are detected it is normal practice to replace the battery charger.

4.9 Station Grounding Systems - Performance

The condition of grounding connections above ground are routinely checked during routine maintenance and station inspections. Continuity tests or other tests on the grounding system are not routinely carried out to determine the grounding condition below grade.

Hydro One has a continuing program to evaluate the adequacy of station grounding facilities at all high risk stations. The criteria used to select these sites were age, fault levels, history of faults, phase arrangement, soil resistivity, station size, location(urban or rural) and redevelopment of adjacent properties.

To date more than 100 stations have been completed, at the rate of about 10 stations per year. These evaluations consist of soil resistivity measurements, full determination of the ground network, fall of potential measurements and application of a software based model to assess the potential rise, and step and touch potentials for a maximum fault level.

Almost all of the stations evaluated between 1999 and 2009 were found to be in need of some grounding improvements.

Approximately 25% of the grounding systems assessed was found to be in “Very Poor” condition and at a very high risk of failure. Major refurbishment of these was required as soon as possible to remove potential safety hazards. All safety related items of an urgent nature which are uncovered by the grounding evaluations are addressed and repaired immediately they are
reported. Also, approximately 40% of the grounding systems assessed were found to be in either “Fair” or “Poor” condition and at a risk of failure requiring refurbishment within the next five years to remove potential safety hazards. The remainder of the evaluated grounding systems assessed was found to be in “Good” or “Very Good” condition.

The below grade grounding evaluations generally found deficiencies in the implementation of present station grounding practices and in some stations deterioration of the surface stone barrier was identified. In general it was found that mesh, structure and fence tough potentials coordinated with safe body withstand potential for summer and winter conditions at the majority of the stations except for some specific fence locations within certain stations. Remediation of the crushed stone installation by replacement or removal of grass, clay, sand was required in some areas within many of the stations evaluated, in order to coordinate touch potentials with the safe body withstand potentials.

Serious below grade deficiencies, such as pedestal bus support structures in the switchyard found to be disconnected from the rest of the station grounding system, were discovered at several of the locations evaluated. Poor condition of the fence grounding was found at several of the stations.

The grounding problems identified above grade mainly deal with the need to keep the station facilities in line with present grounding practices and standards.

### 4.10 AC/DC Station Service Equipment - Performance

Generally while the AC and DC station service systems must comply with regulatory requirements regarding performance and reliability they are treated as part of the station infrastructure and are inspected and functionally tested during routine station inspections, typically on a quarterly basis.

For critical stations the NPCC Criteria Document A-03 “Emergency Operation Criteria”, section 4.10.1 (System Restoration - Testing Requirements), details a number of tests that must be performed regularly at certain stations to ensure that facilities are available when required. Hydro One has identified a total of 70 stations that are on the list of key facilities needed to initiate restoration following a blackout (Basic Minimum Power System, BMPS).

Except for a few significant system events and problems related to a limited number of certain key components over the past 10 years performance of these systems has been generally acceptable. The most significant event was the July 20, 2002 Bruce “B” Switchyard incident that resulted in loss of total station DC supply caused by the automatic DC transfer scheme.

As with other infrastructure components, observation of significant damage or deterioration or any loss of functionality detected from inspection or as a result of alarms are addressed by appropriate remedial action. Consideration for more significant intervention, i.e. refurbishment or replacement of systems would normally only occur if the level of ongoing work was high or if
a specific report indicated serious degradation or performance issues such as in the case of transfer switches for both the AC and DC systems.

In these cases a systematic condition assessment is carried out since the company became aware of widespread problems via the incident reporting, routine inspection and referral processes. Other than in these circumstances, end-of-life would normally be related to other activity in the substation, i.e. major development, renovation or replacement of major plant and equipment.

5.0 Protection System Asset Descriptions

This section provides descriptions of Protection and Control assets that are found at Hydro One Stations. Protection systems consist of either a single or multiple primary measuring relay units and a host of auxiliary devices that provide logic functions. Primary measuring relays are complex devices with predictable expected life spans. Auxiliary devices such as simple relays and timers are considerably more robust.

The major components in protection system are:

- Primary measuring relays - Electromechanical, Solid State, Digital
- Auxiliary devices - Simple relays, Timers, Logic Controllers
- Panels or Racks - 19 inch rack, Steel panel, Ebony asbestos
- Mounting hardware - Primary relay cases, Auxiliary relay cases

5.1 Protection Relays

Protective relays and their associated systems are devices connected throughout the transmission system for the purpose of sensing abnormal conditions. They detect and isolate in conjunction with circuit breakers any abnormal conditions resulting from natural events, physical accidents, equipment failure or mal-operation due to human error. Protective relays and their associated protection systems are therefore indispensable for the safe and healthy operation of the transmission network.

The maximum time allowed for power system protection to correctly sense and isolate faulted equipment whether a transmission line, power transformer etc. is measured in a fraction of a second. High-speed isolation is necessary to protect and mitigate damage to expensive system equipment, reduce the health and safety risks to public/personnel and to maintain power system security/reliability.

Both failure to operate and incorrect operation can result in major power system upsets involving increased equipment damage, increased personnel hazards and possible long interruption of service. These stringent requirements with high potential consequences make it imperative that protection systems be extremely reliable. Protective devices come in three forms or technologies described as follows.
**Electromechanical:** Utilizes the principles of electromagnetic induction to convert electrical energy to mechanical movement to provide fault detection. An example of this type is shown in Figure 45.

![Figure 45: Electromechanical Relay Panel](image)

**Solid State:** Transistor and integrated circuit technology provide the means of fault detection. An example of this type is shown in Figure 46.

![Figure 46: Solid State Relay Panel](image)
**Digital:** The latest microprocessor based technology provides advanced fault detection capability. An example of this type is shown in Figure 47.

![Digital Primary Schweitzer Relays](image)

**Figure 47: Digital Primary Schweitzer Relays**

Protection relays may be either rack mounted, or located in the instrument compartment of switchgear. Older style electromechanical primary measuring relays are also mounted in cases specifically made for them that then mount on panels or racks.

### 5.2 Auxiliary Devices

Auxiliary devices include relays and timers that are usually mounted in auxiliary cases that in turn are mounted on panels or racks.

Three broad categories of auxiliary devices exist.

Type 1: Auxiliary relays and timers manufactured by ASEA used in their modern combliflex method of case mounting known as RX. This type is shown in Figure 48.
Type 2: Auxiliary relays and timers manufactured by ASEA used in their original method of case mounting known as RR. This type is shown in Figure 49.

Type 3: Auxiliary relays and timers directly panel mounted which include, Westinghouse, General Electric and English Electric type.
The vast majority of these auxiliary devices are either RX or RR.

5.3 Panels or Racks

Protection systems are assembled with the various components such as primary measuring relays, auxiliary devices, terminations and isolation devices mounted on panels or racks. Panels may be 24 inch painted steel, or ebony asbestos. Racks are 19 inches free standing painted steel. A typical installation is shown in Figure 50.

![Figure 50: 24 Inch Steel-Type Panels with Protection, Auxiliary Relays, Flexitest Switches and Current Links](image)

5.4 Mounting Hardware

Auxiliary devices such as relays and timers are usually mounted in auxiliary cases that in turn are mounted on panels or racks. Older style electromechanical primary measuring relays are also mounted in cases specifically made for them that then mount on panels or racks.
5.5 Control System: Remote Terminal Units (RTUs)

RTUs are located at all transformer stations to allow operating control from a centralized master control centre where the operators are located. The RTU provides status indication, alarm and control of all equipment located at the local station. The RTU transmits telemetry quantities such as Watts, VArs, Amps and Voltages used for indicating metering. The RTU may also perform certain control functions such as voltage regulation and breaker synchro-check depending on the station operating requirements.

Most RTUs are microprocessor or PC based and self-diagnosing. Microprocessor based RTUs may be single or dual-redundant depending on the reliability required in each installation. Dual redundant RTUs are also multi-ported to support communications to other electronic devices including Human-Machine Interfaces (HMI) used for local station control. Redundancy is provided in the processors only, since the input and output RTU architectures may be concentrated or distributed depending on the economies related to space constraints and cabling. The PC based installations will have a shorter life cycle and lower reliability than the microprocessor based devices as they have electromechanical data storage mechanisms and a relatively short obsolescence cycle. In some cases, the RTU function is performed as part of a distributed system, or integrated as a secondary function into another P&C system.

Distributed systems consist of networked stand-alone microprocessor-based IEDs that are dedicated to the control metering and annunciation function. In some cases, a protection IED provides a subset of the RTU data as a secondary function as shown in Figure 51.

![GE D25 Distributed RTU Installation - 1999](image)

Most RTUs are not subject to regular maintenance intervals and are only serviced upon failure. The new generation of RTU uses non-volatile memory that must be secured in order to operate
reliably. The non-volatile memory (NVRAM) will have a life expectancy as short as eight years, and, in some cases, as long as the service life of the equipment. Devices with NVRAM with a service life that is less than the RTU will be scheduled for preventative maintenance to ensure that failures do not occur.

5.6 Protection System Monitoring

Protection system monitoring devices, including annunciators, digital fault recorders (DFRs) and sequence of events recorders (SERs) are widely deployed in transmission stations to provide detailed information on protection operation. The annunciators currently in use are solid-state electronic devices and the DFRs and SERs are microprocessor and PC based. The capability and sophistication of these devices has been rapidly developing over the past 15 years. As a result of this rapid development, issues of obsolescence, functionality, spare parts and support, particularly related to compatibility with modern IT and communication systems, are the main end-of-life factors. Condition is not normally a significant issue.

Fibre Optics

In the 1990s many electric utilities installed fibre optic links using either a wrap around on the overhead groundwire of their transmission lines, an underslung self-supporting cable or fibres integral with the overhead groundwire. In some cases these were comprehensive systems linking all the main sites in the company, in others it was limited to a few experimental links. There were some initial problems related to the installation processes causing damage to the fibres and some difficulties with splices, but subsequently we believe that the systems have proved reliable and effective.

Metallic Cables (Pilot Cables)

These are used to provide telecommunication channels for protection and control purposes. Based on UK and North American company experience, these are subject to periodic insulation resistance tests and continuity checks. These measures enable degradation to be detected and monitored, with unacceptable levels stipulated in the maintenance manuals. In many cases metallic cables are self-monitored, any indication that they are outside specified limits would trigger an alarm.
Site Entrance Protection Systems

This category consists of equipment required to protect metallic telecommunication cables (Hydro One and those of the telephone companies) that enter high voltage transmission facilities. The predominant equipment type is the neutralizing transformer; other types include isolating transformers and optical isolators. The most important functions performed by this equipment are safety of people and sustaining the operation of teleprotection systems during power system faults.

Teleprotection Tone Equipment

This equipment is a system utilizing telecommunication systems (usually owned by telecommunication companies) to send blocking or tripping signals to remote locations for protection purposes. The equipment owned by the electric utility is typically limited to the ‘send and receive’ multi-channel electronic devices in the transmission stations. The system is quite widely used as an alternative to metallic (pilot) wires.

Timing tests are carried out during commissioning and on watchdog monitors once the system has been commissioned. Some utilities carry out regular ‘timing’ tests to check the performance and functionality of the system. As with other electronic equipment these are repaired or replaced when failures occur. As they are multi-channel devices there is often some built in redundancy allowing flexibility in managing failures.

6.0 Protection and Control - Demographics

This section provides demographic data for Protection and Control assets that are found at Hydro One Stations.

There are approximately 10,300 relay systems in Hydro One, which are made up of approximately 70,000 individual relays. Technology changes over the years have lead to the adoption of three basic classes of relays. Prior to the emergence of solid state electronics relays used analogue electromechanical mechanisms. While this technology is relatively dated these relays have performed well for many decades and are still amongst the most reliable. With the emergence of solid state electronics in the sixties and seventies electronic/digital were adopted to meet the increasing demands of the power system and the need for more complex protections following the blackouts of 1965. More recently computerized relays are increasingly being used to replace aged and failed relays. Figure 52 shows the distribution in ages of all types of relays. Clearly substantial portions of the population have service lives well in excess of what might be expected of electronic or electromechanical devices.
The demographics of the Hydro One’s protection systems broken down by voltage classes are shown in Table 21 below. Approximately 24% of these are more than 30 years old.

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>&lt;50kV</th>
<th>115kV</th>
<th>230kV</th>
<th>500kV</th>
<th>Total</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-10yrs</td>
<td>1005</td>
<td>516</td>
<td>515</td>
<td>76</td>
<td>2112</td>
<td>21%</td>
</tr>
<tr>
<td>11-20yrs</td>
<td>942</td>
<td>325</td>
<td>517</td>
<td>165</td>
<td>1949</td>
<td>19%</td>
</tr>
<tr>
<td>21-30yrs</td>
<td>1347</td>
<td>885</td>
<td>1304</td>
<td>224</td>
<td>3760</td>
<td>37%</td>
</tr>
<tr>
<td>31-40yrs</td>
<td>745</td>
<td>626</td>
<td>631</td>
<td>11</td>
<td>2013</td>
<td>20%</td>
</tr>
<tr>
<td>41-50yrs</td>
<td>111</td>
<td>166</td>
<td>35</td>
<td>0</td>
<td>312</td>
<td>3%</td>
</tr>
<tr>
<td>&gt;50yrs</td>
<td>49</td>
<td>98</td>
<td>0</td>
<td>0</td>
<td>147</td>
<td>1%</td>
</tr>
<tr>
<td>Total</td>
<td>4199</td>
<td>2616</td>
<td>3002</td>
<td>476</td>
<td>10293</td>
<td>100%</td>
</tr>
<tr>
<td>(%)</td>
<td>41%</td>
<td>25%</td>
<td>29%</td>
<td>5%</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

Table 21: Protection Profile

The total count of 519 RTUs is comprised of various generations of electronic devices. Approximately 45% of these are less than 5 years old as shown in Table 22.
### Remote Terminal Units

<table>
<thead>
<tr>
<th>Age Classes</th>
<th>Total</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-5yrs</td>
<td>232</td>
<td>45%</td>
</tr>
<tr>
<td>6-10yrs</td>
<td>159</td>
<td>31%</td>
</tr>
<tr>
<td>11-15yrs</td>
<td>93</td>
<td>18%</td>
</tr>
<tr>
<td>&gt;15yrs</td>
<td>35</td>
<td>7%</td>
</tr>
<tr>
<td>Total</td>
<td>519</td>
<td>100%</td>
</tr>
</tbody>
</table>

Table 22: Control Systems Profile

#### 7.0 Protection and Control Asset Performance

With adverse demographic data as discussed above performance data, not unexpectedly, are showing signs of problems in the P&C category. For example Figures 53 and 54 show the causes of 230 kV transformer outages and 230 kV circuit breaker outages. The focus here is on the proportion of failure causes attributed to protection failures and to control failures. While these data are a small sample, they illustrate how relay and control system failures can have significant impacts on other critical assets and underline the importance of developing plans to maintain and improve performance in the face of the demographic problem.

![230 kV Transformer Forced Outages](image-url)
Dominant Cause for Forced Outage Occurrences

Figure 54: 230 kV Breaker Forced Outages
8.0 Lines Asset Descriptions

This section provides descriptions of Overhead and Underground Transmission assets that are found at Hydro One Stations.

8.1 Overhead Transmission Lines

The primary elements of overhead transmission lines include conductors, supporting structures, insulators, shieldwire hardware and the rights-of-way upon which they are constructed. The bulk of Hydro One’s overhead lines are constructed using aluminum conductors reinforced with a steel core. The conductors are supported by steel structures, porcelain insulators and connecting hardware. The lines are protected from lightning strikes by shield wires mounted above the conductors.

Conductors

Transmission line conductors carry electrical energy from generating stations to transformation stations where the transmission voltage is lowered and the energy is redistributed to customers through distribution line conductors, generally of smaller capacity than the transmission conductors. Normally three conductors (one for each phase) constitute a single circuit, with an operating voltage on the circuit that results in phase-to-phase voltages between the conductors.

Figure 55 shows the Aluminum conductor, steel reinforced (ACSR) in a cut view. ACSR is the most prominent type of conductor used on transmission systems.

Figure 55: ACSR Conductor
In ACSR conductor the steel core strands supply the majority of the conductor’s strength, which enables it to withstand the forces applied from wind, snow and ice as well as its own weight. The steel strands have both tensile and ductile properties so that they are able to withstand longitudinal forces and bending movements respectively, without failure. Individual aluminum strands of wire are laid over the core of galvanized steel wires, with a pitch length that is dependent on the diameter of the core over which it is arranged. Subsequent additional layers of aluminum wire strands are then applied with a reverse pitch, alternating with each additional layer.

The alternating pitch of the aluminum layers create a design that has some capability to reduce movement of the conductor as a result of the friction between the layers of aluminum strands. Some conductors are constructed with flat segmented aluminum strands that result in a smaller diameter for the same cross-sectional area and, as an added bonus, also increases the frictional surface areas between layers of the strands thus improving resistance to conductor swing and vibration. This design also has a reduced tendency for radio and television interference, as the corona discharges are less on a smooth round outer conductor surface.

The determination of the number of steel wires in the core is dependent on the strength of conductor required whereas the number of layers of aluminum is dependent on the amount of current the conductor is designed to carry.

Conductor sizes used in the transmission system range in diameter from 1.43 cm (just over half an inch) to 4.069 cm (just over one and a half inches).

The conductors are supported from structures at intervals (175 metres to 325 metres depending on operating voltage and height of supporting structures) and at tensions up to 222 kN that result in the conductor being elevated a minimum safe distance above the ground at its lowest point between structures at its design operating temperature, with a safety factor.

Conductors are arranged on the supporting structures with sufficient clearance from the structures, ground, overhead shieldwire and other phase conductors to prevent the operating voltage from flashing over between the various elements. The spacing arrangement also takes into account the ability of conductors to gallop (move in an up and down and/or sideways motion) during icing and wind conditions. Insulators with adequate strength to support the physical loads that will be encountered during anticipated weather conditions support the conductors. Between the supporting structures (spans) the insulating medium is air and this insulating quality is taken into account in the separation of the conductors along the route of the circuit.

As load current passes through the conductor the resistance of the conductor causes its temperature to rise. The change in temperature is proportional to the square of the load current passing through it. This rise in temperature causes the conductor to lengthen and to sag between the points of support, thus reducing the height of the conductor above ground. This factor can easily result in a reduction of clearances from ground in the order of 3 metres or more depending on the temperature increase of the conductor, the ambient temperature, wind and solar conditions.
and the distance between points of support. It is critical, therefore, to limit the amount of load carried by each transmission circuit to a level that is within its design capability.

The energy transported on the conductors consists of electrons that have a tendency to travel through the outer layers of the current carrying aluminum strands (skin effect). This results in the inner layers of the aluminum strands not being utilized to their full extent. To overcome this phenomenon the 500 kV system, a design is used where each phase consists of two or more individual conductors of smaller diameter that are held close to each other (approximately 45 cm apart) by means of mechanical connectors. Not only is this type of construction more efficient, it has better (reduced) corona performance and an ability to reduce the amount of conductor movement during wind and ice conditions.

The design most commonly used by Hydro One in the above situations is where four individual conductors form one phase conductor and are held apart in the shape of a 45 cm square which is shown in Figure 56. The surface area available for the current (energy) to flow in this design is now much greater than in a single conductor of equivalent size and thus the efficiency in transporting energy is enhanced.

![Figure 56: Four conductor bundle with spacer](image)

**Shieldwires**

Shield wires are either smaller ACSR conductors or galvanized steel stranded conductors mounted above the phase conductors and solidly connected to ground through the tower steel or ground conductor. Their function is not to carry load current but rather to shield the current carrying conductor from lightning strokes and safety dissipate the energy to ground.

### 8.2 Supporting Structures

A transmission line represents a mechanical system made of components such as conductors, ground wires, supporting structures (including wood poles, steel towers, and steel poles) with
foundations, insulators, hardware and fittings. These transmission lines transport electrical energy from the generating facilities to transformation stations, large industrial customers and to municipal electric utilities.

The wood poles are harvested from various species of trees grown naturally in many parts of Canada. The tree species in use include Western Red Cedar, Jack Pine and Georgian Yellow Pine. These different species of trees have different strength and performance characteristics that are considered in the overall design of a transmission line. The mechanical and structural designs of overhead transmission lines are based on safety, reliability and security requirements. Wood has been a popular material for use in building transmission lines because of its cost effectiveness and reliability over the life of the asset, i.e. low capital and maintenance costs and ease of construction. Wood is a renewable resource and Canada has traditionally had a large supply of suitable trees for this purpose.

Wood poles are graded according to strength by class numbers (i.e. Class 1, 2, 3,...), where the smaller the number, the stronger the pole. Transmission wood pole lines are usually constructed with Class 2 or stronger poles to meet the design loading requirements of the transmission line.

Wood poles and cross-arms are normally treated with preservatives (e.g. creosote, pentachlorophenol or most recently, chromated copper arsenate) in order to prevent premature decay and extend their useful lives.

Wood structures also have a copper or aluminum wire installed across the cross-arm and down the length of the pole to connect all metallic materials and hardware to a metallic ground rod. This arrangement conducts any stray leakage currents to ground to prevent a wood pole or cross-arm fire.

The two basic transmission wood pole design types in use by Hydro One are “H Frame” design and “Single Pole” design. These are used for all tangent (in line) and small angle applications. For larger angles and dead-ending, a 3-pole semi-strain or dead-end structure design is used.

- H-Frame Structures (Figure 57) consist of two poles and a cross-arm. In some cases there are guy wires attached to the poles near the cross-arm and then attached to ground anchors located at 90 degrees from the direction of the line. Other means of reinforcing such structures incorporate cross-braces installed in an X configuration between the vertical poles. Due to the design of such structures they require more materials, occupy more right-of-way and are stronger than single pole structures.
The “Single Pole” design uses a single pole of suitable height, in the range of 17 to 30 metres. Conductors are then suspended using steel arms with suspension insulators (Figure 58); the older “wishbone” design using two cross-arms attached at different points on the pole and slanted to provide spacing for the attachment of the three phase conductors they support (Figure 58; or standoff insulators (Figure 59). These structures are less expensive due to the use of less material, are not as strong and occupy less right of way than the H-frame structures.
Figure 59: Single Pole Design, “Standoff”
8.3 Rights-of-Way

An overhead transmission line right-of-way (Tx-ROW) is a continuous, urban or rural land corridor with an established legal right for Hydro One to construct, operate, and maintain electrical utility transmission lines. The primary function of these corridors is for the transmission of electrical energy in a safe and reliable manner. The Tx-ROW asset provides the land base for building and/or installing structures and stringing conductors at a variety of voltage levels with appropriate access for operating and maintaining those facilities.

The Tx-ROW corridor is required as part of the transmission system whereby conductors at voltage levels of 115 kV, 230 kV and 500 kV are used to transmit electrical energy to customers from the various generation and supply sources throughout its service territory. Engineering and Design standards and the type of supporting structures determine Tx-ROW corridor width requirements. Conductors energized at voltage levels of 115 kV, 230 kV, and 500 kV require Tx-ROW widths averaging 30 m, 46 m and 64 m respectively. Tx-ROW corridors may contain one or more circuits. These circuits may form a single or multi-circuit line and they may or may not be at the same voltage levels. Multi-circuit line corridors vary in width and may require Tx-ROW clearing as wide as 220 m.

All new high voltage transmission line projects are required to go through an Environmental Assessment and approval process. This is to ensure that the potential social and economic impact of transmission line facilities and corridors have been addressed and have been dealt with in a satisfactory manner. The steps of the Environmental Assessment and approval process ensures that the selection of a preferred route for the new transmission line is determined after considering all environmental, cultural, social and economic impacts. This process may also rely on public hearings to assess alternative routes and to determine the final preferred route. The outcome of this process is an Order in Council (OIC) from the government that gives Hydro One the rights to acquire property and/or easements for the purpose of constructing the transmission line facilities. The OIC gives Hydro One the right to clear property of woody vegetation; to acquire and construct access; to erect or install overhead and underground conductors.

The OIC also gives Hydro One the authority to operate and maintain the equipment and the Tx-ROW within prescribed guidelines. Operation and maintenance of the transmission line includes the requirement to maintain clearances between vegetation and the transmission facilities and the rights of access.

Hydro One’s Tx-ROW properties occupy Crown Lands, (through License of Occupation), patent lands, (through easement rights), First Nation Lands (through easements), and lands owned outright by Hydro One.

All agreements governing Tx-ROW must have rights to conduct vegetation maintenance activities on the Tx-ROW and the right to manage trees on adjacent lands that pose a threat of falling into the line or growing into the minimum allowable side clearances thereby interfering with the safe operation and reliability of the line. Where vegetation has been allowed to encroach on the originally constructed width of the Tx-ROW, re-establishing the Tx-ROW to design width is an important aspect to the successful and safe operation of the transmission system.
Managers of vegetation programs are dealing with a biological system that is constantly changing. If a Tx-ROW is not maintained, in short time, through natural succession, it will revert back to the original forest cover.

**Tx-ROW in Rural Areas**

Tx-ROW in rural areas traverse both long narrow paths (single transmission lines with one or two circuits on one line) and wider Tx-ROW and shorter distances (multiple transmission lines on one corridor). However, some of the multi line corridors traverse long paths such as the lines between Otto Holden to North Bay to Sudbury to Missisauga.

The Tx-ROW system touches on many of the geological landforms found in Ontario as well as all forest regions ranging from deciduous to boreal to tundra. Local topography associated with any one Tx-ROW can range from low to high relief, from poorly drained bogs to well drained eskers, and from bedrock ridges to sand flats. Extreme topography, rivers, streams, wetlands, lakes and lack of road development can restrict Tx-ROW access. The adjacent land uses can also vary widely from rural residential developments, agriculture, managed woodlots, orchards, and mining to remote wilderness.

On Tx-ROW in rural areas, additional management constraints can apply in response to land owners when dealing with Tx-ROW located on First Nations lands, Federal lands, railway lands, Provincial lands and patented lands. The change in vegetation species mix through each of the Forest Regions in the Province results in different maintenance cycle requirements and a need for a variety of methods and tools for managing vegetation.

**Tx-ROW in Urban Areas**

Hydro One has transferred all its urban transmission corridors to Provincial ownership but still remains responsible for their maintenance. These urban corridors have essentially become grassed open areas, designated green belt and industrial or commercial lands. Urban corridors support a wide range of vegetation ecosystems associated with stream valleys, steep slopes, naturalized areas, maintained grasslands, un-maintained grasslands, scrub lands, recreational/park lands and industrial lands. Urban corridor land uses range from leases to cover commercial parking lots, transportation and industrial uses to agriculture, golf courses and landscaping nurseries to areas of “quiet enjoyment” and green belts. All urban Tx-ROW must be managed to the conditions and standards of the community within the bounds of local municipal bylaws and approvals. These owned properties total approximately 9,300 hectares in large population centres such as Metro Toronto and Greater Toronto Area, Ottawa, and Niagara Falls and 10,900 hectares in smaller population centres.

However, the high cost of lands in urban areas also provide an opportunity for compatible secondary land uses that generate revenue and, when successfully pursued, also reduces the total land area requiring maintenance expenditures by Hydro One. These factors lead to a different
strategy for conducting ground maintenance and vegetation control on urban Tx-ROW, than rural Tx-ROW.

### 8.4 Underground Cables

Transmission underground cables are typically extensions to, or links between, portions of the Networks’ overhead transmission system operating at 115 kV and 230 kV. There are no underground cables in the 500 kV system. Underground cables are mainly used in urban areas where it is either impossible, or extremely difficult to build overhead transmission lines due to legal, environmental and safety reasons.

The initial capital cost of a transmission underground cable circuit is about 10 times higher than the cost of an overhead transmission line of equivalent capacity and voltage. Transmission underground cables are also more costly to maintain/repair than an overhead transmission line and they pose environmental risks not present with overhead transmission lines as some are filled with pressurized insulating/cooling liquids.

Depending on the cable design the three phase conductors may be contained together within a steel pipe or each phase conductor is self-contained in its own sheath and installed separately underground. Transmission underground cables are systems, similar to transmission lines, made up of numerous components, all of which need to integrate and function properly in order to deliver the electric power with the reliability that is demanded.

There are several different types of high voltage underground cables in use on the Networks’ transmission system:
- Low-Pressure Liquid-Filled (LPLF) Cables
- High-Pressure Liquid-Filled Pipe-Type (HPLF) Cables
- Extruded Cross Linked Polyethylene (XLPE) Cables:

#### Low-Pressure Liquid-Filled (LPLF) Cables

This design features a hollow core conductor to carry insulating liquids, which saturates and maintains the dielectric strength of the lapped paper insulating layers over the cable core. The cable is mechanically protected by an aluminium or lead shield, which in turn is protected from corrosion by an insulating polyethylene or rubber jacket.

The cable system is maintained continuously under positive liquid pressure from liquid reservoir tanks, either gravity fed or pressurized tanks situated at the terminal ends, and occasionally along the cable route. In unusual situations, due the cable route, elevations and length, a low pressure pumping plant may be used.

This type of cable is almost invariably installed as three individual phases in a horizontal configuration with a separation of 15-20 cm directly in an excavated trench or in a concrete encased duct bank. The trench is backfilled with material that retains moisture and conducts heat away from the cables.
An example of this type of cable is shown in Figure 60.

![Figure 60: Low-Pressure Liquid-Filled (LPLF) Cables](image)

**High-Pressure Liquid-Filled Pipe-Type (HPLF) Cables**

This cable design features the three phases of a cable circuit installed within a steel pipe. The pipe not only holds the cable phases, but also liquid maintained under high pressure (200 psi) by pumping plants located at the cable terminations. The pipe is a welded carbon steel pipe, coated on the exterior with protective coatings, and cathodically protected to prevent corrosion. The three phase conductors contained within the pipe are each wrapped with lapped paper taped insulation and an outer metallic foil tape to control voltage gradients between the conductor and the outer layers of paper insulation.

The free space surrounding the phase conductors is pressurized with insulating liquid supplied from an electrically controlled pumping plant located at the cable terminal end. Some of these pumping plants are now equipped with PLC and computer control systems, which improve operational efficiency, and have an early leak detection system.

An example of this type of cable is shown in Figure 61.
Extruded Cross Linked Polyethylene (XLPE) Cables

This cable type is a simple design which consists of an extruded polyethylene insulation covering the phase conductor, mechanically protected by a lead sheath and covered with a polyethylene jacket to provide corrosion protection. Similar to LPLF installations, XLPE cables are installed as three individual phases in an excavated trench or concrete encased duct bank. An example of this type of cable is shown in Figure 62.

Figure 61: High-Pressure Liquid-Filled Pipe-Type (HPLF) Cable

Figure 62: Extruded Cross Linked Polyethylene (XLPE) Cables
9.0 Lines Asset Demographics
9.1 Overhead Transmission Lines Demographics

Transmission lines comprise one of the primary components in electric power systems. They are designed to transmit power over long distances and they provide the multiple interconnections between generation and load that makes up the power grid. Hydro One has 542 overhead transmission circuits having a total length of 28,438 km and 120 underground transmission cable circuits having a total length of 270 km. In the following sections we describe Hydro One’s asset sustainment plans for these two types of transmission lines.

The age distribution of transmission phase conductors shown in Table 23.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>Circuit Length (Circuit -km)</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 - 10yrs</td>
<td>1,015</td>
<td>3.57%</td>
</tr>
<tr>
<td>11 - 20yrs</td>
<td>1,760</td>
<td>6.19%</td>
</tr>
<tr>
<td>21 - 30yrs</td>
<td>2,070</td>
<td>7.28%</td>
</tr>
<tr>
<td>31 - 40yrs</td>
<td>5,600</td>
<td>19.69%</td>
</tr>
<tr>
<td>41 - 50yrs</td>
<td>3,113</td>
<td>10.95%</td>
</tr>
<tr>
<td>&gt;50yrs</td>
<td>14,880</td>
<td>52.32%</td>
</tr>
<tr>
<td>Total</td>
<td>28,438</td>
<td>100.00%</td>
</tr>
</tbody>
</table>

Table 23: Transmission Line Population by In-Service Year

The amount of energy demand in southern Ontario resulted in fairly large amounts of energy being transmitted in a north-south direction and a very large quantity being transmitted in an east-west direction. Although the distances are shorter in Southern Ontario, the large loads being supplied along the phase conductors has meant a higher density of line construction in southern Ontario with larger conductors.

In addition, there are several points on the borders of Ontario where transmission lines are connected to neighbouring utilities in Manitoba, Minnesota, Quebec, New York and Michigan. These connection points are used for transferring energy into or out of the province as required to meet the needs of the overall area.
There are a total of 41,112 transmission wood pole structures installed on the transmission system. Of this total approximately 85% are installed on 115 kV transmission system and approximately 15% are installed on the 230 kV system, as shown in Table 24.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>Voltage Level</th>
<th>Total</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>115 kV</td>
<td>230 kV</td>
<td></td>
</tr>
<tr>
<td>0 - 10yrs</td>
<td>4,102</td>
<td>12</td>
<td>4,114</td>
</tr>
<tr>
<td>11 - 20yrs</td>
<td>1,168</td>
<td>81</td>
<td>1,249</td>
</tr>
<tr>
<td>21 - 30yrs</td>
<td>337</td>
<td>105</td>
<td>442</td>
</tr>
<tr>
<td>31 - 40yrs</td>
<td>3,205</td>
<td>3,854</td>
<td>7,059</td>
</tr>
<tr>
<td>41 - 50yrs</td>
<td>2,077</td>
<td>639</td>
<td>2,716</td>
</tr>
<tr>
<td>&gt;50yrs</td>
<td>23,701</td>
<td>1,841</td>
<td>25,542</td>
</tr>
<tr>
<td>Total</td>
<td>34,590</td>
<td>6,532</td>
<td>41,122</td>
</tr>
</tbody>
</table>

Table 24: Wood Pole Age Demographics

Hydro One manages approximately 81,579 hectares of rights of way for transmission lines. In addition, approximately 2000 hectares are retained for possible future transmission use and transformer stations occupy 2421 hectares. The individual Tx-ROW land areas vary in width based on the voltage level of the conductors and type of construction, with a larger portion of the lower voltage narrower corridors occurring in the North. Generation plants that supply electrical energy are located in both Northern and Southern areas of the province. With the greater industrial base and human population located in the south, there is a need to augment the southern supply with energy generated in the north. The land area for Tx-ROW in northern Ontario is 32,704 ha and 48,875 ha in the south (Tables 25). The length of the Tx-ROW in the province for different voltage levels is shown in Table 26.

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Geographic Area of Ontario</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Northern (Hectares)</td>
<td></td>
</tr>
<tr>
<td>115 kV</td>
<td>15,314</td>
<td>8,787</td>
</tr>
<tr>
<td>230 kV</td>
<td>12,881</td>
<td>26,719</td>
</tr>
<tr>
<td>500 kV</td>
<td>4,509</td>
<td>13,369</td>
</tr>
<tr>
<td>Total</td>
<td>32,704</td>
<td>48,875</td>
</tr>
</tbody>
</table>

Table 25: Transmission ROW Land Area
Hydro One currently manages approximately 270 circuit-km of 115 kV and 230 kV high voltage cable systems that are primarily located in the urban centres of Toronto, Hamilton and Ottawa, with some minor systems in Windsor, London, Sarnia, Picton and Thunder Bay. The first cables were installed in 1951. Table 27 shows the age demographics of underground cable circuits presently in service.

<table>
<thead>
<tr>
<th>Age Group</th>
<th>HPLF Cables</th>
<th>LPLF Cables</th>
<th>XLPE Cables</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>No. of Circuits</td>
<td>Circuit Length (Circuit-km)</td>
<td>No. of Circuits</td>
<td>Circuit Length (Circuit-km)</td>
</tr>
<tr>
<td>0 - 10yrs</td>
<td>9</td>
<td>12.1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>11 - 20yrs</td>
<td>6</td>
<td>25.1</td>
<td>7</td>
<td>3.3</td>
</tr>
<tr>
<td>21 - 30yrs</td>
<td>17</td>
<td>42.6</td>
<td>7</td>
<td>5.4</td>
</tr>
<tr>
<td>31 - 40yrs</td>
<td>24</td>
<td>66.5</td>
<td>1</td>
<td>1.8</td>
</tr>
<tr>
<td>41 - 50yrs</td>
<td>7</td>
<td>18.8</td>
<td>23</td>
<td>40.8</td>
</tr>
<tr>
<td>&gt;50yrs</td>
<td>3</td>
<td>6.3</td>
<td>21</td>
<td>42</td>
</tr>
<tr>
<td>Total</td>
<td>66</td>
<td>171.4</td>
<td>59</td>
<td>93.3</td>
</tr>
<tr>
<td>(%)</td>
<td>63.1%</td>
<td>34.3%</td>
<td>2.6%</td>
<td></td>
</tr>
</tbody>
</table>

Table 27: Transmission Underground Cable Demographics

Table 28 shows that the majority of cables installed on the system are of the HPLF / LPLF type.
<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Cable Type</th>
<th>No. of Circuits</th>
<th>Circuit Length (Circuit-km)</th>
<th>Total No. of Circuits</th>
<th>Total Circuit Length (Circuit-km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>115 kV</td>
<td>HPLF</td>
<td>52</td>
<td>137.9</td>
<td>95</td>
<td>221.4</td>
</tr>
<tr>
<td></td>
<td>LPLF</td>
<td>42</td>
<td>78.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>XLPE</td>
<td>5</td>
<td>4.7</td>
<td></td>
<td></td>
</tr>
<tr>
<td>230 kV</td>
<td>HPLF</td>
<td>14</td>
<td>33.5</td>
<td>38</td>
<td>49.8</td>
</tr>
<tr>
<td></td>
<td>LPLF</td>
<td>21</td>
<td>14.4</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>XLPE</td>
<td>3</td>
<td>1.9</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 28: Voltage Breakdown of Underground Circuits

10.0 Lines Asset Performance

Line performance trends and comparisons with CEA and Canadian averages is provided in Figures 60 to 62 below.

![Figure 60: 500 kV Circuit Performance](image-url)
While the frequency of sustained outages is relatively good and trending towards further improvement, the duration of sustained outages is high in comparison with other utilities.