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May 11, 2020

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Transmission System and Terminal Station Asset Management Execution Report

In its correspondence dated October 13, 2016[1] the Board of Commissioners of Public Utilities ("Board") required Newfoundland and Labrador Hydro ("Hydro") file annual reports on transmission system and terminal station asset management execution, including the status of completion of activities in relation to the annual plan and the following year's plan.

Attached please find Hydro's annual report on transmission system and terminal station asset management. The report includes the completion status of activities in relation to the 2019 annual work plan and information relating to Hydro's 2020 planned activities.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/sk.kd

Encl.

ecc: **Board of Commissioners of Public Utilities**
Jacqui Glynn
Maureen P. Greene, Q.C.
PUB Official Email

Newfoundland Power
Gerard M. Hayes
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[1] Correspondence related to the Board's Phase One Report from the Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System.

Consumer Advocate
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Industrial Customer Group
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Teck Resources Limited
Shawn Kinsella

Transmission System and Terminal Station Asset Management Execution Report

May 11, 2020

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

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1.0 Introduction

On October 13, 2016, the Board of Commissioners of Public Utilities ("Board") requested Newfoundland and Labrador Hydro ("Hydro") provide an annual report on Hydro's transmission system and terminal station asset management execution, including the status of the completion of activities in relation to the Annual Work Plan ("AWP") and information relating to the following year's planned activities.

Transmission system and terminal station assets provide the means by which generated electricity can be delivered directly to high-voltage customers and to the distribution system serving the remaining customers. Hydro maintains equipment for 3,904 km of transmission lines and 69 terminal stations for the Island and Labrador Interconnected Systems. This infrastructure is composed of numerous types of assets in various quantities. Through the application of asset management activities during the life cycle of these assets, Hydro works to provide reliable electricity delivery at least cost. Hydro's asset management activities include:

- Installation of new assets;
- Refurbishment of existing infrastructure and equipment to meet expected operating conditions;
- Execution of maintenance activities to maintain reliable operations; and
- Asset assessments to provide appropriately-timed refurbishment and replacement activities of infrastructure and equipment.

These activities are conducted within an asset management system by personnel in Long-Term Asset Planning ("LTAP"), Short-Term Planning and Scheduling ("STPS"), and Work Execution divisions within Hydro.

This report provides:

- Hydro's Asset Management Life Cycle Model;
- Roles and activities of the personnel in LTAP, STPS, and Work Execution;
- Background on transmission system and terminal station equipment function and asset management practices;
- Background on capital-related interactions;

- Completion status of 2019 AWP maintenance activities and capital transmission system and terminal station projects; and
- Planned 2020 AWP maintenance activities and capital transmission and terminal station projects.

In light of the ongoing COVID-19 pandemic, Hydro is actively reviewing and prioritizing its AWP for 2020. This review and prioritization effort is expected to continue through the year as the situation evolves.

2.0 Life Cycle of Assets

At Hydro, new assets are brought into the system based on: reviews of load growth and new customer requests; configuration changes for improved reliability; and asset refurbishment or renewal based upon condition and/or reduced reliability. Assets are maintained until condition assessments or asset management practices deem they are no longer fit for service, or are no longer of use to Hydro's electrical system. Assets are disposed of as per Hydro's established practices.

3.0 Roles of Asset Management Personnel

3.1 Long-Term Asset Planning

LTAP personnel focus on an asset over its entire life cycle to achieve reliable, least-cost service, and to implement replacement or refurbishment of the asset in a manner that optimizes its service life while avoiding unacceptable failures. To accomplish this objective, LTAP personnel work with Engineering and Technology personnel to: establish standards and practices for equipment and infrastructure installations to meet operating conditions and provide reliable service; and to review the commissioning results of newly installed equipment. LTAP personnel also develop, monitor, and improve maintenance programs and procedures through the implementation and monitoring of condition assessment techniques. These results are then incorporated into asset maintenance regimes or the timing of capital plans for replacement or refurbishment. LTAP personnel also incorporate failure analysis corrective actions into the above activities to improve asset reliability. Additionally, LTAP personnel are responsible for establishing and monitoring spare equipment requirements.

To begin an asset's life cycle, LTAP personnel will ensure assets are entered and configured correctly into the computerized maintenance management system, ensure the correct preventive maintenance ("PM") cycle is communicated to STPS personnel, and ensure the correct check sheet for the maintenance is available. If required, LTAP personnel will update the maintenance manual to reflect any new maintenance tactics that may be required.

3.2 Short-Term Planning and Scheduling

Based upon the maintenance procedures and frequencies determined by LTAP personnel, STPS personnel develop the AWP to execute the asset maintenance activities and schedule execution of the planned and required corrective maintenance ("CM") work. STPS personnel undertake the detailed efforts required to schedule and execute this work by determining the human resources, tools, procedures, and equipment that are required, and subsequently requisition necessary materials, tools, and equipment.

3.3 Work Execution

Work Execution management and LTAP personnel review CM work orders to determine the priority of the work. When approved, STPS personnel will plan and schedule the work, as appropriate.

Work Execution personnel focus on the execution of work orders that result from STPS weekly scheduling activities. STPS personnel assign labour and parts to the work order and also move it to the work execution staff to execute. The work execution personnel are responsible for ensuring the work is completed properly. After completion of the work, the work order is updated with information on activities performed and any completed check sheets are attached. This information is filed and used by LTAP, Work Execution, and STPS groups to improve maintenance practices and to assess the condition of assets.

4.0 Capital-Related Interactions

Resource and Transmission Planning personnel identify new infrastructure required due to load growth, new major customer requests, and electrical system reliability improvements. LTAP personnel identify asset renewal or refurbishment requirements based upon asset condition assessments, asset management practices, and/or reduced reliable operation. Asset condition is normally determined by a review of completed PM and CM work orders as well as formal condition assessments, original equipment manufacturer recommendations, and other asset-specific criteria or legislative criteria.[1] Once capital work on an asset is identified, it is placed in the long-term plan in the appropriate year for

[1] An example would include polychlorinated biphenyl ("PCB") Management.

refurbishment or replacement. LTAP personnel monitor the asset condition, and adjust execution timing as required.

For each annual Capital Budget Application submitted for Board approval, detailed justifications, scopes, and estimates are prepared from the long-term plan preliminary scope statements, justifications, and estimates. Each project is reviewed by various groups within Hydro including Engineering and Technology, asset owners, LTAP, Regulatory Affairs, and Finance.

Once the Capital Budget Application is approved, project execution teams, as part of Hydro Engineering and Technology, are assigned to execute the projects. The teams ensure appropriate design standards are followed, all necessary equipment is procured within the correct specifications, equipment and infrastructure are properly installed, commissioning and energization plans are developed, spare parts are identified for new assets, as-built drawings are completed, and Operation and Maintenance manuals are made available to the LTAP, STPS, and Work Execution groups.

Once the assets from the project are commissioned and placed into service, the assets are transitioned to regional staff for operation and maintenance.

5.0 Terminal Stations Asset Management

Hydro has 69 terminal stations as part of the Island and Labrador Interconnected Systems, with some having assets dating back to the late-1960s. These stations contain electrical equipment such as: transformers; circuit breakers; instrument transformers; disconnect switches; arresters; and associated protection and control relays and equipment required to protect, control, and operate Hydro's electrical system.

Terminal stations play a critical role in the transmission and distribution of electricity. They act as transition points within the transmission system and interface points with the lower voltage distribution and generation systems.

The following sections provide a summary of the maintenance, refurbishment and replacement criteria Hydro uses for terminal station assets. Attachment 1 "Terminal Station Asset Management Overview"[2] included in the Terminal Station Refurbishment and Modernization project in Hydro's "2020 Capital Budget Application," provides additional terminal station asset management information. Appendix A

[2] Also provided in "2020 Capital Budget Application," Newfoundland and Labrador Hydro, August 1, 2020, vol. II, Report 7b.

provides additional information on the maintenance program for various major asset classes for terminal stations.

5.1 Power Transformers and Oil-Filled Shunt Reactors

Power transformers are critical components of the power system. Transformers allow the cost-effective production, transmission, and distribution of electricity by converting the electricity to an appropriate voltage for each segment of the electrical system. On the Island and Labrador Interconnected Systems, Hydro has 118 power transformers and three oil-filled shunt reactors that are 46 kV and above, as well as several station service transformers at voltages lower than 46 kV.

Electrical insulation aging is directly related to transformer operating temperatures, and therefore it is critical that transformers operate as cool as economically possible. The majority of Hydro's high-voltage transformers are filled with oil for electrical insulation purposes. Higher operating temperatures affect the characteristics of the transformer oil which, in turn, lowers the strength of the insulation within the transformer. As a result, transformer oil cooling systems, as well as transformer winding and oil temperatures, are checked regularly. Additionally, it is important for the transformer oil to be tested to ensure acceptable oil quality, strength of insulation, and acceptable levels of dissolved gases. Doble Tests[3] are performed to measure the overall insulation of the transformer, as well as the bushings, and helps provide an overall condition of the unit. A winding resistance test is used to determine if there are any loose connections or shorted turns inside the transformer. Other important tests are also completed for the transformer protective devices such as gas, winding, and oil temperature relays. In the event of a problem within the transformer, these devices provide a warning alarm. For more severe conditions, these protective devices can cause breakers to trip, which will remove the unit from service.

Power transformers of 46 kV and greater are currently replaced for any of the following:

- Degree of polymerization ("DP") less than 400 for network transformers and less than 500 for generator step up transformers (in Asset Criticality A);
- Uncontrollable gassing; an indication of an internal fault; or
- Requirement for major refurbishment in the near-term (to maintain/restore reliability), but replacement is a lower cost alternative.

[3] Doble Tests are high-voltage insulation tests that examine the overall integrity of high-voltage equipment through power factor and capacitance measurements.

Due to the aging nature of the transformer fleet in a maritime environment, Hydro has developed an ongoing refurbishment program to cover bushing replacements, radiator replacements, oil refurbishment, moisture reduction, on-load tap changer overhaul and leak repair, transformer leak repair, protective device replacement, transformer painting, and installation of on-line Dissolved Gas Analysis monitors.

5.2 Circuit Breakers

Circuit breakers operate to complete, maintain, or interrupt current flow under normal or fault conditions. The failure of a breaker to operate properly may affect reliability and safety of the electrical system, resulting in failure of other equipment and electrical outages to customers. Hydro has 230 terminal station circuit breakers in service of 46 kV and greater on the Island and Labrador Interconnected Systems. Hydro utilizes three types of circuit breakers throughout the system. They are Sulphur Hexafluoride ("SF_6"), air blast, and oil-filled circuit breakers.

To ensure reliable operation, breaker operating mechanisms are inspected, lubricated, and tested to ensure low contact resistance and contact opening and closing timing within manufacturer's guidelines.

SF_6 circuit breakers (46 kV[4], 69 kV, 138 kV and 230 kV) are planned for overhaul at 20 years and replacement at 40 years. However, as replacements of SF_6 breakers come due, a further condition assessment will be completed to determine if more life can be achieved through other means such as an overhaul . Replacement can also occur sooner than 40 years if their condition dictates. Oil circuit breakers are not overhauled and all are planned for replacement by 2025 due to the suspicion that bushings contain PCBs greater than 50 parts per million. There is a Federal Government environmental mandate to remove such bushings by 2025. Air blast circuit breakers are no longer overhauled due to execution of a project to have all air blast circuit breakers replaced with SF_6 circuit breakers by the end of 2022.

5.3 Instrument Transformers

Instrument transformers convert high voltage and high current into low voltages and currents for use in protection, control, and metering equipment.

[4] Hydro uses 72.5 kV class breakers for breakers utilized in 46 kV and 69 kV systems.

If the oil contained in the majority of Hydro's high-voltage instrument transformers for electrical insulation purposes were to leak from the device, it could fail. Therefore, visual inspections are required to find oil leaks and Doble testing is also used to confirm the high-voltage insulation integrity of the unit.

Corrosion is also common in instrument transformer junction boxes, which contain secondary wiring and terminal blocks connected to protection, control, and metering equipment. The older designed junction boxes were constructed of mild steel. Severe rusting of these junction boxes could allow water to leak into the junction box, causing corrosion of electrical terminals and affecting the reliability of the protection circuits. Severely corroded junction boxes on transformers are replaced with either aluminum or stainless steel junction boxes.

Instrument transformers are currently replaced for any of the following reasons:

- Deteriorated condition (rust);
- Deteriorated condition as a result of poor Doble results;
- Unit is suspected to contain PCBs greater than 50 parts per million;
- The transformer is a 230 kV Asea IMBA Current Transformer ("CT"), [5,6] or
- Units are targeted for replacement at an age ≥ 40 years.

5.3 Surge Arresters

Surge arresters provide over-voltage protection for equipment resulting from lightning strikes or switching surges. Arrester failure is likely to result in a fault. To ensure the devices are reliable, arresters are visually inspected for contamination or cracking of the insulator. Arresters also undergo Doble testing to confirm overall condition.

Arresters are replaced if:

- Doble testing has indicated a failed unit;

[5] IMBA is a model of current transformer manufactured by Asea AB.
[6] The failure of a 230 kV IMBA-type CT at the Holyrood Terminal Station in 2010 prompted the engagement of a consultant to provide a CT tear-down investigation. One recommendation from the consultant's report was to remove all 230 kV IMBA-type CTs within Hydro's system in a planned approach. Following the consultant's recommendation, all IMBA-type CTs were identified and included in the instrument transformer replacement program. "2013 Capital Budget Application," Newfoundland and Labrador Hydro, August 2012, vol. II, Report 14 "Replace Instrument Transformers Various Locations."

- Visual inspection identifies severe contamination or insulator cracking;
- The arrester type is prone to failure;
- Deemed necessary during a transformer replacement; or
- They are 40 years of age. This is to reduce the risk of in-service failures and minimize service interruptions.

5.4 Disconnect Switches

Disconnect switches are used as isolating devices to enable other equipment to be removed from service and restored to service safely. It is critical that all electrical contacts open or close properly when required. When high-voltage disconnect switch contacts do not close properly a high resistance connection can occur resulting in overheating of the contacts. This heating can melt the contacts and damage the disconnect switch causing the circuit breakers to operate and, depending on the terminal station configuration, cause a customer outage. Visual inspection and infrared scans are performed to ensure any disconnect switches function, both manually and electrically. Switches are also lubricated and functionally tested annually.

Replacement of a disconnect switch is primarily decided based upon its condition, identified operating problems, issues determined during maintenance, or when there is a requirement for excessive CM. Secondary prioritization for the long-term plan is based on an equipment age of 50 years or obsolescence, which makes it difficult to find replacement parts.

5.5 Protection and Control Relays

The terminal station protection and control system automatically monitors, analyzes, and triggers action by other terminal station equipment, such as opening of breakers, to ensure the safe, reliable operation of the electrical system. The system also initiates operation of equipment when a command is issued by system operators. The protection and control system provides indications of system conditions and alarms and records system conditions for analysis.

Relays are tested and recalibrated to ensure they operate correctly. During 230 kV breaker PM activities, the entire system from relays to high-voltage circuit breakers are operated to ensure the overall protection system functions properly. As well, after a protection operation on the system, engineering personnel review the event data to ensure protective relaying operated correctly. If there was a malfunction of the relaying, corrective actions are implemented.

There are two types of relays used throughout Hydro's system—digital solid-state (new and older vintage) and the older electromechanical design.

Protective relays are replaced based on performance, obsolescence, age, and the inability to provide the desired protection functionality and information required for fault analysis. Hydro has a protective relay replacement program for electromechanical and obsolete solid-state relays. This plan includes the completion of the 230 kV relay replacement by 2028 and further development of the plan to replace the 138 kV- and 69 kV-related relays.

Additionally, there are programs to upgrade alarm systems, breaker failure protection, and transformer tap changer paralleling controls in terminal stations.

The electromechanical and older digital solid-state relays lack features such as data storage and event recording capability; therefore, modern digital multifunction relays are used to replace these older style relays. The modern digital multifunctional relays have increased setting flexibility, fault-disturbance monitoring, communications capability, metering functionality, and offer greater dependability and security, thus enhancing system reliability.

5.6 Battery Banks and Chargers

Battery banks and chargers provide direct current ("dc") power supply to protection and control equipment, circuit breakers, and disconnect switches. Battery banks are visually inspected for leaks and contact corrosion, and are tested annually for contact conductance. Discharge testing is completed for battery banks during factory acceptance testing and is scheduled after 10 years of service and every 5 years thereafter for criticality A and B flooded cell banks and every 2 years on criticality A and B valve-regulated banks.

Based upon experience, Hydro plans replacement of flooded cell battery banks after 20 years of service, valve-regulated lead acid ("VRLA") batteries after 10 years of service, and chargers after 20 years of service. Equipment condition and operating problems are also considered and equipment is replaced sooner, if necessary.

5.7 Capacitor Banks

Capacitor banks are required at various locations on the system to provide voltage control for different system conditions. These banks are typically made up of capacitor modules in series and parallel.

Capacitor banks are visually inspected for insulating oil leaks or insulator cracking. PM activities, conducted on a six-year cycle, will clean the capacitor bank and execute capacitance testing.

Hydro replaces capacitor banks based upon condition and considers replacement after the capacitor bank has been in service for 45 years.

5.8 Air Systems

Air systems consist of both compressors and air dryers. They are used mainly to supply dry air to air blast circuit breakers. For air blast circuit breakers to operate correctly, dry air must be available. Maintenance for compressors and dryers ranges from monthly visual inspections and cleaning to annual performance and function testing. Overhauls are undertaken as warranted by equipment condition.

With the existing condition of the air systems and an ongoing program to replace air blast circuit breakers by 2020, Hydro is not planning to replace air dryers or compressors needed for those breakers.

Some SF_6 and oil-filled circuit breakers use compressed air in the operating mechanism. Any remaining compressors used for those breakers will be assessed for replacement.

5.9 Grounding

The grounding system in a terminal station or distribution substation consists of: copper wire used in the ground grid under the station; gradient control mats for high-voltage switches; bonding wiring connecting the structure and equipment metal components to the ground grid; and a crushed stone layer. In the event of a line-to-ground fault, electrical potential differences will exist in the grounding system. If the grounding system is inadequate or deteriorated, these differences may be hazardous to personnel. These potential differences are known as step and touch potentials. Effective station grounding reduces these potentials to eliminate the hazard.

Hydro will continue with its grounding upgrade program, in which disconnect switch gradient control mats have been replaced, and grounding systems are upgraded in accordance with IEEE,[7] 80-2013, "IEEE Guide for Safety in AC Substation Grounding," 2013.

[7] Institute of Electrical and Electronics Engineers ("IEEE").

5.10 Insulators

Insulators provide electrical insulation between energized equipment and ground. Terminal stations contain solid core, cap and pin, multi-cone, and suspension type insulators.

When an insulator fails and a fault occurs, a safety hazard to personnel and customer outage may occur.

For insulators using porcelain, cement is used in mating the porcelain and metal hardware. Some older insulators have failed by a phenomenon known as "cement growth."[8] In such situations, pieces of falling porcelain are a hazard to personnel and equipment below the insulator. Furthermore, when an insulator failure causes a fault, customer outages may occur. Hydro replaces identified cement-growth insulators in its capital program.

5.11 Steel Structure and Foundations

Reinforced concrete foundations support high-voltage equipment, structures, and bus work. The majority of these foundations were installed during the original station construction and are in excess of 35 years of age. Age, as well as exposure to freeze/thaw cycles and other weather elements, can cause deterioration and impact the foundation's structural integrity. When routine visual inspections identify significant damage, refurbishment or replacement of the foundation is included in Hydro's capital program.

5.12 Control Buildings

The control buildings house protection, control, and supervisory control and data acquisition ("SCADA") equipment, as well as battery banks and chargers. Control buildings are inspected for leaks and general building and life safety condition during 120-day terminal station inspections. Hydro has an ongoing program to address capital deficiencies.

5.13 Synchronous Condensers

Hydro maintains two synchronous condensers located at the Wabush Terminal Station. Each synchronous condenser undergoes major and minor inspections on a three year rotating cycle, with minor inspections performed in both year one and year two of the cycle, and a major inspection performed in year three. Each inspection involves a standard list of checks, tests, and completion of

[8] Cement growth is a phenomenon where cement grout expands due to moisture egress, which leads to radial cracks of porcelain insulators.

general maintenance including any additional items that have been identified for follow-up based on the results of previous inspections.

The minor inspections involve function testing, vibration checks, lube oil system maintenance and oil sampling, disassembly and inspection of top half of bearings, clearance checks, electrical tests, visual inspections, as well as cleaning and general maintenance including replacement of various gaskets, filters and hardware.

The major inspections expand on the same activities performed under the minor inspections by also pulling the rotor for rotor and stator inspection, disassembly and inspection of the bottom half of the bearings, and replacement of the thrust bearings

5.14 Asset Criticality and Spares

Hydro has developed a terminal station asset criticality ranking for selected asset classes based on such things as available alternatives (e. g., parallel transformers), environmental impact, customer impact, likelihood of breakdown, and cost of repairs. This is considered in prioritizing maintenance and capital work. Hydro uses such factors as well as other equipment specific factors to establish asset criticality rankings for power transformers, circuit breakers, battery banks and chargers, and disconnect switches. In 2020, Hydro will continue development of asset criticality rankings for terminal stations as a whole.

In 2020, Hydro plans to continue with procurement of spares for power transformer tap changers and bushings, synchronous condensers at the Wabush Terminal Station, and protection and control relays. Procurement of any identified spares will be completed in 2020 and 2021. Hydro also reviews its spare terminal station equipment on a routine basis and takes action or establishes plans to achieve appropriate spares levels based on the outcome of those reviews.

6.0 Transmission Line Asset Management

Hydro owns approximately 583 km of 69 kV; 1500 km of 138 kV; and 1821 km of 230 kV transmission lines as part of the Island and Labrador Interconnected Systems, for a total line length of approximately 3904 km.[9] Hydro also owns approximately 30 km of 46 kV sub-transmission lines in Labrador West.

[9] L2303 and L2304 from Churchill Falls to Wabush are 230 kV lines which are 215 km in length. These lines are leased by Hydro from Churchill Falls (Labrador) Corporation Limited. Maintenance on these lines is performed by Churchill Falls (Labrador) Corporation Limited through an agreement with Hydro, with Hydro responsible for asset planning.

Hydro's 69 kV-class lines are of wood pole construction and the 138 kV-class lines are primarily comprised of wood pole and aluminum lattice structures. The 230 kV class lines are a combination of wood pole and steel lattice construction. Over half of these assets were constructed in the 1960s and early-1970s.

Transmission lines are a set of conductors supported by structures that carry electrical power from generation plants to terminal stations and link terminal stations together, allowing for the distribution of electricity to customers. A transmission line consists of structures, conductors, insulators, grounding system, and rights-of-way.

The primary subcomponents of a steel structure are the legs, cross members, and grillage foundations which are typically fabricated from structural angle steel. These subcomponents are hot-dip galvanized to ensure extended life. A typical lattice steel structure can last in excess of 70 years.

The primary subcomponents of a wood pole structure are the poles, crossarms, and cross braces. These subcomponents are treated with preservatives to ensure extended life. A typical treated wood pole can last in excess of 60 years. Typically, treated crossarms and cross braces can last in excess of 30 years.

6.1 Wood Pole and Steel Structure Line Management Programs

Wood Pole and Steel Structure Line Management Programs are the primary means by which Hydro maintains and refurbishes its transmission lines. These cyclical programs include structure-climbing inspections, wood pole Resistograph readings and shell thickness measurements, and visual inspections of conductors, guying, and foundations. LTAP personnel establish condition-based assessments to identify and prioritize capital work and CM activities so as to extend line life expectancy. The condition-based data collected is also used to determine when a total line replacement is required. As component replacement quantities increase beyond the budgetary framework of the pertinent line management program, separate capital projects are placed into the long-term plan for line upgrades.

6.2 Helicopter Patrols

Helicopter patrols are carried out twice a year on transmission lines. These patrols conduct visual inspections of the transmission line from the air and look for visible defects and right-of-way deficiencies, such as danger trees. Hydro captures video on all helicopter patrols, which allows for further assessment after completion of the patrol. All deficiencies are documented and scheduled for corrective work.

6.3 Ground Patrols

Ground patrols are generally carried out as part of the Wood Pole and Steel Structure Line Management Programs. Lines exposed to high-loading conditions have annual ground patrols which conduct visual inspection from the ground to identify, assess, and prioritize deficiencies to a transmission line and its right-of-way. Identified deficiencies are documented and scheduled for corrective work.

6.4 Infrared Inspections

Hydro completes infrared scanning of connections on dead end structures on all transmission lines. All deficiencies are documented and scheduled for corrective work.

6.5 Wood Pole Treatment

Preservative treatment is added to the poles to extend their service life through the Wood Pole Line Management ("WPLM") Program.

6.6 Right-of-Way Maintenance

A transmission line runs along a corridor typically referred to as a right-of-way. The width of the right-of-way depends on the voltage class of the transmission line, or if several lines run through the same corridor. Uncontrolled vegetation growth may eventually lead to outages due to conductor contact or travel access restrictions on the right-of-way due to thick brush. During transmission line inspections, tree height and vegetation growth are noted in addition to areas that need repairs, such as washouts. The work to control vegetation is prioritized based on condition. Hydro utilizes a combination of cutting and spraying to control vegetation growth on its rights-of-way. Hydro performs vegetation control on approximately 10% of its rights-of-way per year with 60% of the annual program involving vegetation cutting and the remaining 40% of the vegetation sprayed with herbicide.

6.7 Asset Criticality and Spares

Hydro has developed a transmission line asset criticality ranking based on the health of each piece of equipment, available alternatives (e.g., radial lines), environmental impact, customer impact, likelihood of breakdown, and cost of repairs. These factors are considered in prioritizing maintenance and capital work. Rankings have been established for all transmission lines using this approach.

Hydro reviews its spare transmission materials on a routine basis. From these reviews action is taken or plans are established to achieve appropriate spares levels.

7.0 Status of Planned 2019 Transmission System and Terminal Station Activities

The completion status of the AWP and Winter Readiness ("WR") activities for transmission system and terminal station facilities on the Island and Labrador Interconnected System is summarized in the following sections.

7.1 Transmission System

As shown in Figure 1 to Figure 4, Hydro completed 100% of its planned 2019 transmission system AWP and WR activities.

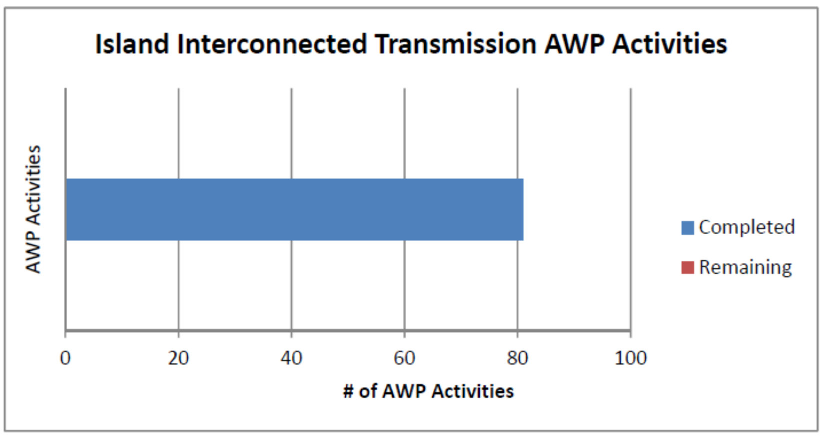

Figure 1: 2019 Transmission System AWP Activities for the Island Interconnected System (December 31, 2019)

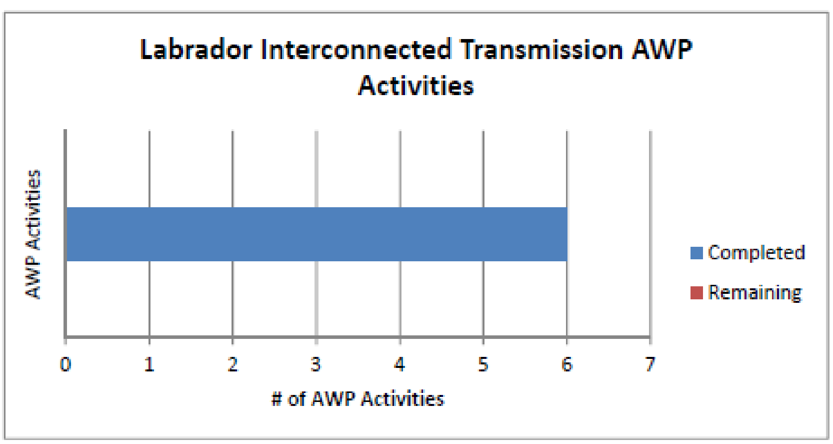

Figure 2: 2019 Transmission System AWP Activities for the Labrador Interconnected System (December 31, 2019)

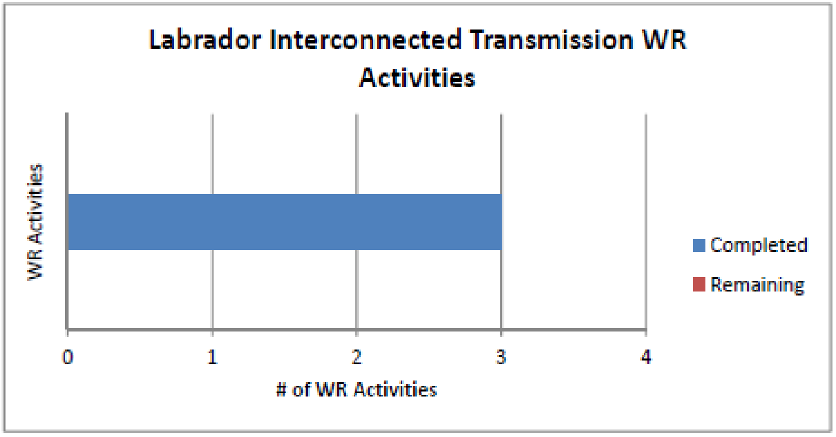

Figure 3: 2019 Transmission System WR Activities for the Island Interconnected System (December 31, 2019)

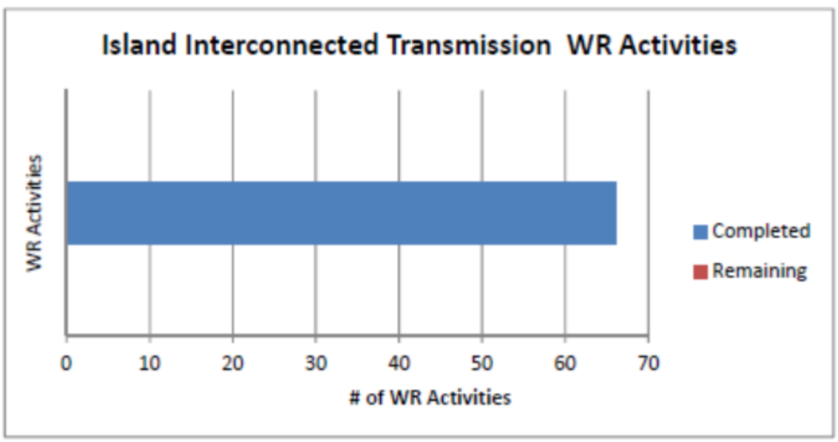

Figure 4: 2019 Transmission System WR Activities for the Labrador Interconnected System (December 31, 2019)

The following is a summary of the transmission system activities completed in 2019:

- TL 267, environmental rehabilitation and project close out, from Bay d'Espoir to Western Avalon;
- Muskrat Falls to Happy Valley interconnection, transmission line build (year 1);
- Completion of the following WPLM inspections and refurbishments; and
  - Inspection on TL 215, TL 219, TL 220, TL 223, TL 226, TL 229, TL 233, TL 239, TL 241, TL 252, TL 256, and TL 257; and

- Refurbishment on TL 203, TL 209, TL 215, TL 218, TL 219, TL 225, TL 227, TL 241, TL245, TL 250, and TL259.

- Completion of Steel Line Inspection Program Inspections, as referenced in Table 1.

Table 1: 2019 Steel Line Climbing/Ground Inspections Completed

Line #	Climbing Inspection (Structures)	Ground Patrol (Structures)
TL 202	104-121, 209-226	131-171 320-355
TL 204	61-70, 198-213	67-88, 101-141
TL 205	126-146	168-208
TL 206	104-121, 212-231	137-172, 326-363
TL 207	16-30	1-30
TL 208	26-46	1-46
TL 211	85-98	112-139
TL 212	296-369	296-369
TL 214	46-91 275-355	223-274
TL 217	226-256	208-256
TL 228	73-90, 201-208	151-187, 189-219
TL 231	88-98, 212-229	22-42, 106-140
TL 236	36-41	1-56
TL 237	37-54	145-179
TL 242	36-42	58-71
TL 247	186-222, 389-402	300-371, 411-445
TL 248	91-109	151-185
L23	43–56, 185–198, 328–341, 471–484	
L24	43–56, 185–198, 328–341, 471–484	
TL 265	6-10	1-50
TL 268	6-10	1-52

7.2 Terminal Stations

As shown in Figure 5 to Figure 8, Hydro completed 94% and 99% of its planned 2019 terminal station Island Interconnected System and Labrador Interconnected System AWP respectively, and 100% of its planned 2019 terminal station WR activities as of December 31, 2019.

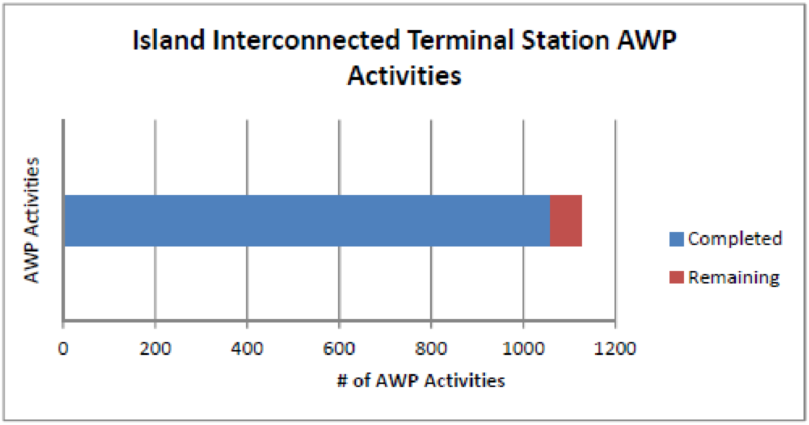

Figure 5: 2019 Terminal Station AWP Activities for the Island Interconnected System (December 31, 2019)

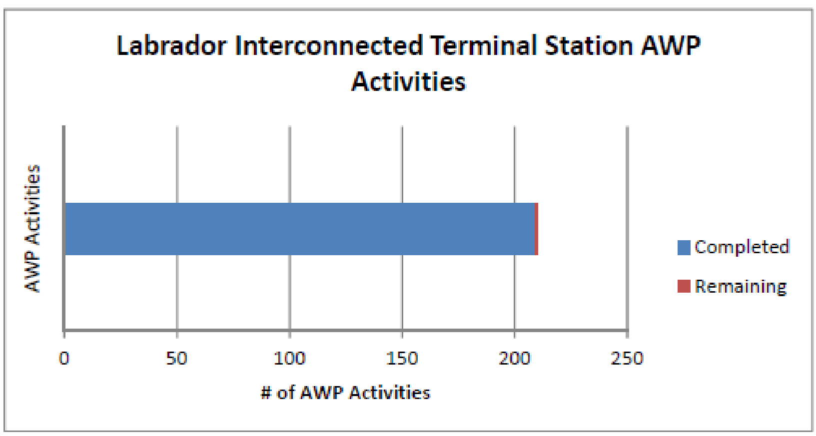

Figure 6: 2019 Terminal Station AWP Activities for the Labrador Interconnected System (December 31, 2019)

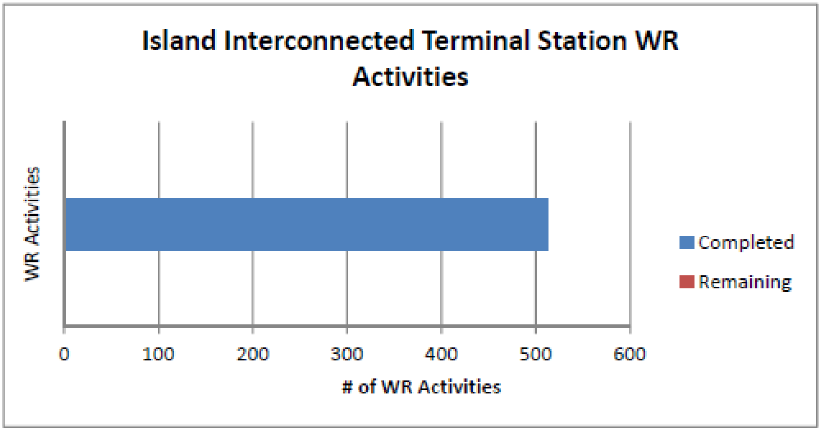

Figure 7: 2019 Terminal Station WR Activities for the Island Interconnected System (December 31, 2019)

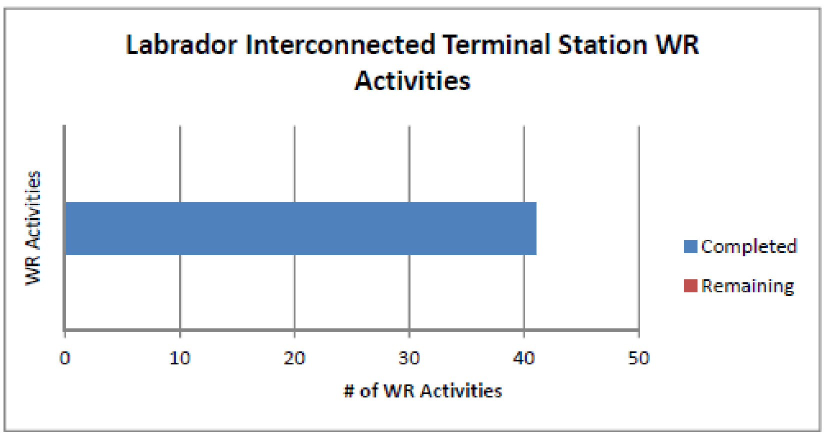

Figure 8: 2019 Terminal Station WR Activities for the Labrador Interconnected System (December 31, 2019)

The following is a summary of the terminal station activities completed in 2019:

- Completed 33 six-year breaker maintenance procedures;
- Operated all 69 kV and above circuit breakers once throughout the year;
- Completed 11 trip from protection breaker maintenance procedures;
- Completed 32 six-year power transformer maintenance procedures and 36 six-year power transformer Doble maintenance procedures;
- Completed Oil Quality and Dissolved Gas Analysis Program for power transformers and tap changers;

- Completed 3 six-year shunt reactor Doble maintenance procedures;
- Completed 164 disconnect switch PM procedures;
- Completed six-year protection and control maintenance procedures at 16 stations;
- Completed 106 six-year instrument transformer Doble maintenance procedures;
- Completed infrared scans at all terminal stations;
- Completed annual battery maintenance at all terminal stations;
- Replaced 3 battery banks;
- Replaced 1 battery charger;
- Purchased 3 mobile dc battery systems;
- Replaced 12 circuit breakers, including 10 air blast circuit breakers and 2 minimum oil circuit breakers;
- Power Transformers: completed 3 oil refurbishments, 3 radiator replacements, and 90 bushing replacements on 16 transformers; installed 1 online oil dehydrator and 7 online gas monitors;
- Replaced 18 surge arrestors;
- Completed oil refurbishment on 3 shunt reactors;
- Replaced 24 disconnect switches;
- Replaced 27 instrument transformers; and
- Replaced protective relays for 6 transmission protection schemes, 4 transformer protection schemes, 5 bus protection schemes, and a terminal station protection scheme;
- Replaced 39 post insulators;
- Replaced 33 suspension insulators; and
- Upgraded 10 terminal station grounding grids.

7.3 Status of 2019 Terminal Station and Transmission Line Capital Projects

Appendix B identifies the capital projects that included planned construction completion in 2019 for assets in terminal stations and on transmission lines, and indicates the completion status of each. Table 2 summarizes the completion status of these projects by asset category.

Table 2: Status of Capital Projects with Planned Construction Completion in 2019

Asset Category	Complete	Partially Complete/ Deferred	Incomplete	Total
Transmission Lines	1	2	0	3
Terminal Stations	10	5	0	15
Total	**11**	**7**	**0**	**18**

Some elements of work in the transmission lines and terminal station asset categories have been deferred to 2020. These are mostly a result of unforeseen events including reprioritization of work, availability of internal engineering and construction resources, and unavailability or shortening of outage windows required to execute work. The deferred work included:

- Muskrat Falls to Happy Valley interconnection, transmission line build (year 1). Line was constructed but has not been placed in service as planned.
- WPLM scope (non-WR) including:
  - TL 220: 1 pole, 1 suspension clamp, 4 hardware, 1 damper;
  - TL 221: 9 cross arms;
  - TL 226: 1 cross arm;
  - TL 227: 1 cross arm;
  - TL 229: 8 cross arms, 6 insulators;
  - TL 241: 1 cross arm, 1 foundation, 12 sets of eyebolts, 4 hardware, 1 guy;
  - TL 250: 2 poles, 2 cross arms, 1 insulator, 2 sets of eyebolts, 1 guy;
  - TL 251: 3 poles, 4 cross arms;
  - TL 252: 1 pole, 1 cross arm, 1 foundation, 2 insulators, 1 conductor repair;
  - TL 253: 20 cross arms; and
  - TL 257: 2 conductor repairs.

While this work has been deferred, Hydro has determined that these deferred activities would not significantly impact the reliability of the Island and Labrador Interconnected Systems for winter 2019–2020. Details regarding the cause of the deferrals, as well as the risk and mitigation through the winter, are provided in the Notes Section of Appendix B.

8.0 Planned 2020 Transmission System and Terminal Station Activities

In light of the ongoing COVID-19 pandemic, Hydro is actively reviewing and prioritizing its AWP for 2020. This review and prioritization effort is expected to continue through the year as the situation evolves.

8.1 Transmission System

As shown in Figures 9 to 12, as of April 17, 2020 Hydro has completed 16.9% of its planned 2020 transmission system AWP activities and 18.5% of its 2020 WR activities for the Island Interconnected System and has not yet commenced work on the Labrador Interconnected System.

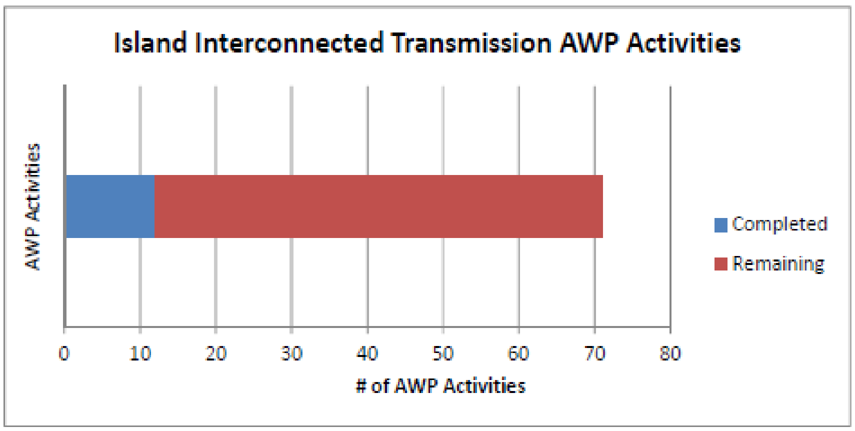

Figure 9: 2020 Transmission System AWP Activities for the Island Interconnected System (April 17, 2020)

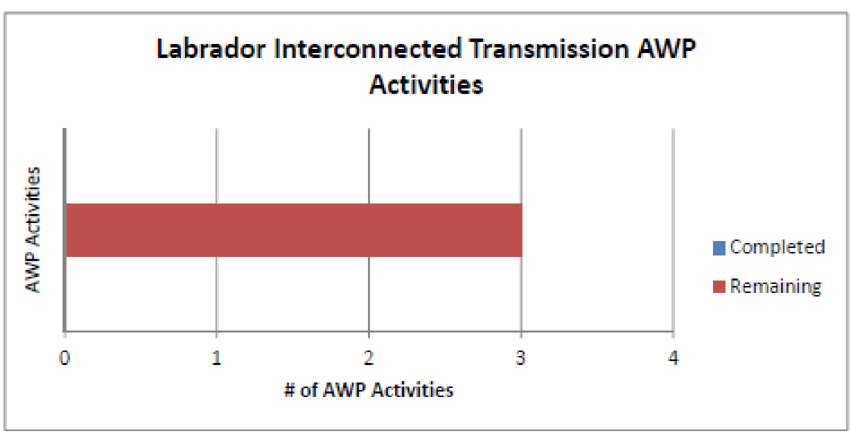

Figure 10: 2020 Transmission System WR Activities for the Island Interconnected System (April 17, 2020)

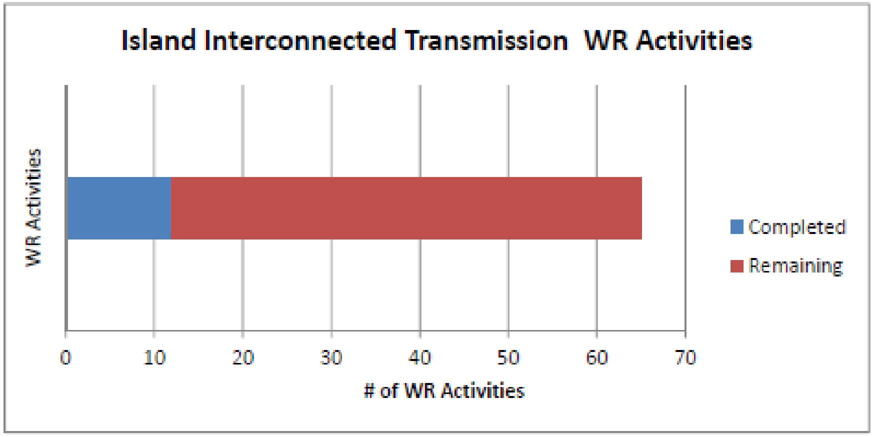

Figure 11: 2020 Transmission System AWP Activities for the Labrador Interconnected System (April 17, 2020)

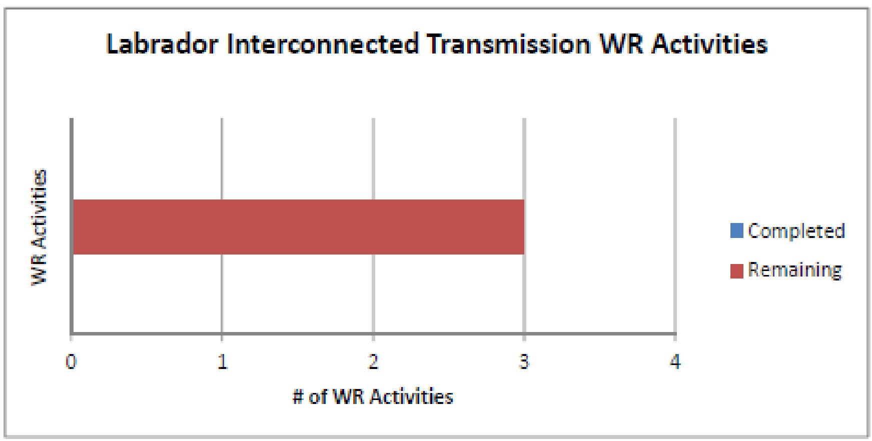

Figure 12: 2020 Transmission System WR Activities for the Labrador Interconnected System (April 17, 2020)

The following is a summary of the transmission system work plan activities scheduled for 2020:

- Muskrat Falls to Happy Valley interconnection, transmission line tie-in L1303 to L1302;
- WPLM inspections and refurbishments:
  - Inspect: TL 209, TL 219, TL 220, TL 226, TL 227, TL 233, TL 238, TL 243, TL 251, TL 254, and TL 257; and
  - Refurbish: TL 215, TL 219, TL 220, TL 221, TL 223, TL 226, TL 227, TL 229, TL 233, TL 239, TL 241, TL 250, TL 251, TL 252, TL, 253, and TL 257.

- Steel Line Inspection Program Inspections, as referenced in Table 3.

Table 3: 2020 Steel Line Climbing/Ground Inspections

Line #	Climbing Inspection (Structures)	Ground Patrol (Structures)
TL 202	122-138, 227-244	1-34, 173-209
TL 204	71-80, 214-230	89-101, 236-264
TL 205	147-167	1-41
TL 206	122-138, 232-249	1-34, 173-211
TL 207	1-15	1-30
TL 208	1-25	1-46
TL 211	99-112	1-27
TL 212	222-295	222-295
TL 214	138-183, 275-355	1-55
TL 217	1-25	1-51
TL 228	91-108, 209-217	1-37, 220-249
TL 231	99-106, 230-247	1-21, 246-278
TL 236	42-47	1-56
TL 237	55-72	1-36
TL 242	43-49	1-14
TL 247	223-260, 372-388	1-74, 372-410
TL 265	11-15	
TL 268	11-15	
TL 248	110-127	1-37
L23	23-33, 56-66, 57-70, 199-212, 342-355, 485-498	
L24	23-33, 56-66, 57-70, 199-212, 342-355,485-498	

8.2 Terminal Stations

As shown in Figure 13 and Figure 14, Hydro has completed 18.0% of its planned 2020 terminal station AWP activities and 23.4% of its 2020 WR activities for the Island Interconnected System as of April 17, 2020. As shown in Figure 15 and Figure 16, Hydro has completed 18.0% of its planned 2020 terminal station AWP activities and 9.0% of its 2020 WR activities for the Labrador Interconnected System as of April 17, 2020.

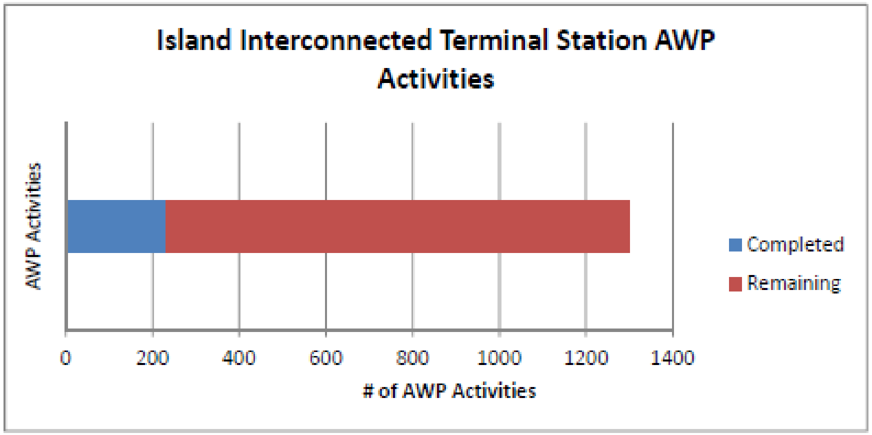

Figure 13: 2020 Terminal Station AWP Activities for the Island Interconnected System (April 17, 2020)

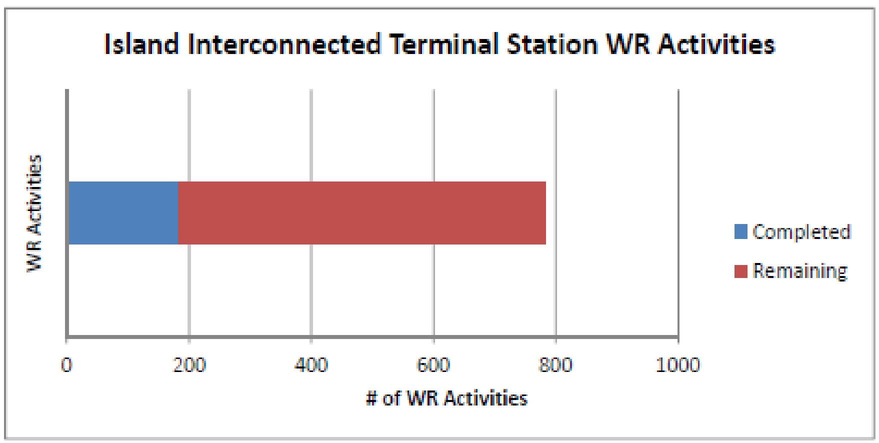

Figure 14: 2020 Terminal Station WR Activities for the Island Interconnected System (April 17, 2020)

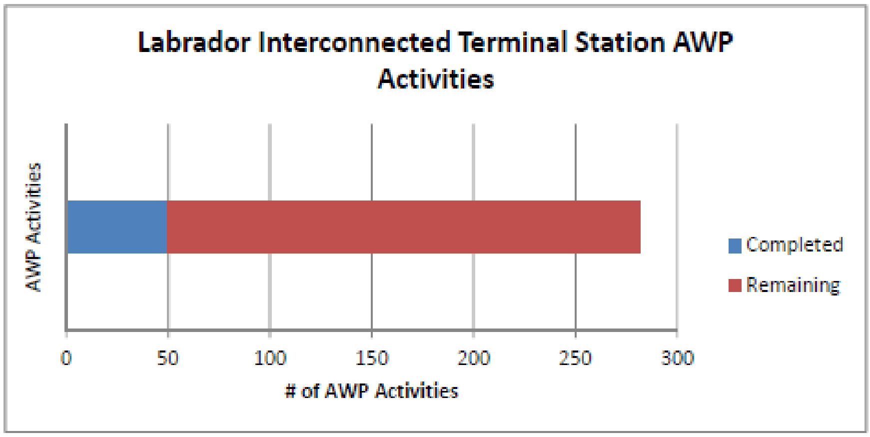

Figure 15: 2020 Terminal Station AWP Activities for the Labrador Interconnected System (April 17, 2020)

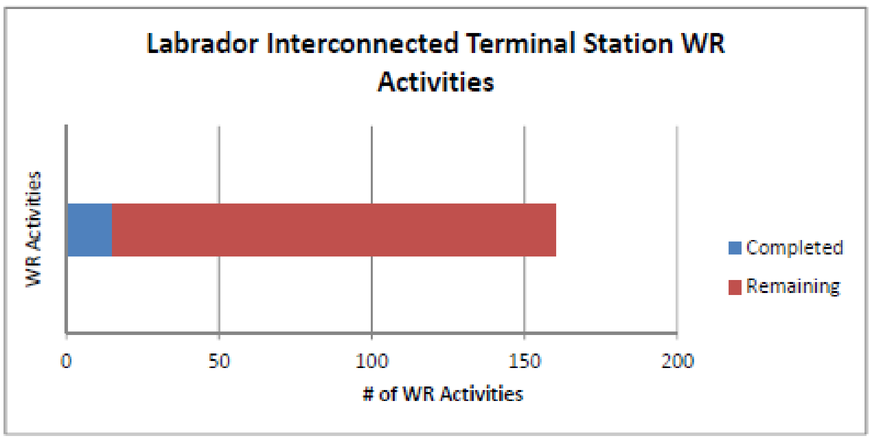

Figure 16: 2020 Terminal Station WR Activities for the Labrador Interconnected System (April 17, 2020)

The following is a summary of the terminal station work plan activities scheduled for 2020:

- Complete 28, six-year breaker maintenance procedures;
- Replace 12 breakers, 7 of which are air blast circuit breakers;
- Operate all 69 kV and above breakers once;
- Complete 14 trip from protection breaker maintenance procedures;
- Complete 37, six-year power transformer maintenance procedures and 23 six-year power transformer Doble maintenance procedures;

- Complete Oil Quality and Dissolved Gas Analysis Program for power transformers and tap changers;
- For power transformers, complete: 1 major refurbishment, 2 radiator replacements, 2 tap changer upgrades, 38 bushing replacements on 6 transformers, and install 8 online gas monitors;
- Replace 9 surge arrestors;
- Replace 1 power transformer;
- Complete annual maintenance on all terminal station battery banks;
- Replace 2 battery banks;
- Complete PM activities on 161 disconnect switches;
- Replace 16 disconnect switches;
- Replace 18 instrument transformers;
- Replace protective relays for 8 power transformer and 3 bus protection schemes;
- Complete 17, six-year protection and control maintenance procedures at 12 terminal stations;
- Complete 74, six-year instrument transformer Doble maintenance procedures;
- Complete infrared scans at all terminal stations;
- Replace 67 post insulators; and
- Upgrade 17 terminal station grounding grids.

Appendix A

Details of Terminal Station Preventive Maintenance Overhaul and Replacement Criteria

Introduction

The following outlines Hydro's PM program and overhaul and replacement criteria for the various major asset classes within terminal stations.

Power Transformers and Shunt Reactors

- 120-day PM: cooling fan function testing, operational data collection, and visual inspection;
- Oil Sample PM (one year by default, more frequently as needed): dissolved gas analysis ("DGA"), oil quality, and moisture;
- Furan PM (four years by default, one year as needed): to test the DP of the paper;
- Six-Year PM: electrical testing (Doble testing, winding resistance, winding insulation resistance, protective device insulation resistance, surge arrester grounding continuity), protective device function testing, tap changer function testing, cooling fan function testing, and visual inspection; and
- Hydro's current replacement criteria for power transformer replacement (46 kV and above) is based upon one of the following:
  - Condition based upon DP <400 for network transformers and <500 for generator step-up transformers in Asset Criticality A;
  - Uncontrollable gassing which is an indication of an internal fault; or
  - Requirement for major refurbishment in the near-term (to maintain/restore reliability), but replacement is a lower cost alternative.

Due to Hydro's aging transformer fleet, Hydro has developed an ongoing refurbishment program to cover bushing replacements, radiator replacements, oil refurbishment, moisture reduction, on-load tap changer overhaul and leak repair, transformer leak repair, protective device replacement, transformer painting, and installation of online DGA monitors. The following sections provide the details for each.

Power Transformer Bushing Replacement

Power transformer bushings are currently replaced for either of the following:

- Condition (bad Doble test results as identified by Doble Engineering, unobservable oil level, non-removable tap caps, or visual damage allowing moisture ingress); or

- Suspected of containing PCB-contaminated oil (All sealed equipment containing >50ppm must be removed from service by 2025).

Prioritization: poor condition first (by condition severity), PCB-contaminated next.

Power Transformer Radiator Replacement

Hydro's replaces power transformer radiators based upon the condition of the radiator (rust) from a visual inspection and ranking by an asset specialist.

Power Transformer Oil Refurbishment

Hydro's oil refurbishment criteria is based upon oil being IEEE Class III or IEEE Class II. Class III units will have their oil either reclaimed or replaced. If the oil has PCB content greater than 2 ppm the oil will be replaced, otherwise it will be reclaimed to improve the oil quality. Class II units will have their oil processed to improve the oil quality.

Power Transformer Moisture Reduction

Hydro's moisture reduction criteria is based upon having paper >3.5% moisture, or paper is >2.5% with inferred DP is <1100, and replacement is not forecasted within ten years of current year.

Prioritization: equal weighting of paper moisture severity and asset criticality.

Power Transformer On-Load Tap Changer Leak Repair

Hydro's criteria to complete leak repair for on On-Load Tap changers is based upon having stable acetylene and other combustible gases in the transformer, and a proven leak test. Units testing positive to leak tests are planned for refurbishment.

Power Transformer On-Load Tap Changer Overhaul

Hydro's criterion for tap changer overhaul is either of the following:

- An annual oil sample to measure dissolved gases and particle count. Hydro uses a Tap Changer Analysis Signature Assessment to provide a ranking of very good (1) to very poor (4). A rank >3 is the criteria for overhaul;
- Stenestam Ratio > 5.0; or

- Number of operations (based upon original equipment manufacturer recommendation for contact maintenance).

Power Transformer Leak Repair

Hydro's criteria to complete leak repairs is based upon:

- Identified leaks.
- Major refurbishment will include gasket replacements to prevent future leaks.

Power Transformer Protective Device Replacement

Hydro will complete transformer protective relay replacements if condition warrants as determined by 120-day or six-year PM. Protective devices and associated cabling is also changed as required during other transformer refurbishment work.

Power Transformer Online DGA Monitors

Hydro's criteria for online DGA monitors is to install full monitoring of all combustible gases for Criticality A and B transformers (GE Transfix) and install GE Hydran units on Criticality C and D units. All data is brought back to a GE Perception Software that is remotely accessible by engineers and asset specialist.

Power Transformer Painting

Hydro's criterion for rust removal and painting is based upon a visual inspection for rust. As well transformers undergoing major refurbishment will have painting considered.

Circuit Breakers

- 120-Day PM: visual inspection, check pressures for air and/or SF_6, record heater amps;
- Annual: operate breaker PM is completed to confirm operation once per year;
- Oil sample from oil circuit breakers every three years;
- Every four years the following is completed for Air Blast Circuit Breakers: Conductor; timing; trip coil measurement; check auxiliary contact; check pressure switches; function test breaker; and measure trip coil resistance;

- Every six years the following is completed for SF_6 Circuit Breakers: check SF_6 pressure; check operating mechanism pressure; check conductor; measure trip coil resistance; check pressure settings; check primary connections; lubricate mechanism; and measure timing and function test breaker;
- Every six years the following is completed for oil circuit breakers: change oil in compressor; check dash pot oil level, breaker in open position; check pressure switches and record, if applicable; inspect contactors; lubricate operating mechanism; measure and record run time of compressor from cut-in to cut-out; measure interrupter resistors (138 kV KSO only), check bushings and wipe down, if required; complete a dielectric test ASTM D877 of the oil; perform megger of each phase to ground with breaker; and perform doctor and timing;
- 69 kV, 138 kV, and 230 kV SF_6 breakers are planned for overhaul at mid-life (20 years) and replaced at 40 years or sooner if condition dictates. 69 kV SF_6 circuit breakers are not overhauled but are planned to be replaced at 40 years or sooner if condition dictates;
- Oil circuit breakers are not overhauled and are being planned for replacement by 2025 due to the bushings being suspect to contain PCBs $\geq$ 50 ppm; and
- Air blast circuit breaker are no longer overhauled and a plan is in place to have all air blast circuit breakers removed from service at the end of 2020.

Protective Relays

- Six-Year PM Inspection: function test each protective relay one at a time—clean, dust, and inspect connections; connect the relay test equipment to the relay; configure the relay test equipment settings to those required for the relay; function test each in-service function of the relay using the relay test equipment; troubleshoot the relay if it fails any function tests; record and save the results in the relay testing software; and return relay to service;
- For electromechanical relays, perform the additional steps: remove glass and clean inside and out; pull biscuit(s) and check for oxidation (tarnished); clean with a white eraser; unlock relay and gently pull out of case; check for iron filings on operating disc, if equipped; clean contact surfaces with a burnishing tool; and manually move disc to look for smooth operation and to ensure it resets properly;

- Every six years, function test 230 kV circuit breakers from the protection during the scheduled 230 kV breaker PM;
- Historically protective relays were replaced based on age, performance, obsolescence, and their inability to provide the desired protection functionality and information required for fault analysis. Following the events of January 2014, Hydro formalized a protective relay replacement plan which will see protective relay systems (which had not already been previously replaced) replaced for all major equipment on the 230 kV system during the period from 2015 to 2026. Further plans will be developed for 138 kV and 69 kV equipment. Additionally, as a result of the events of January 2014 plans have been put in place to upgrade alarm systems and breaker failure protection in major terminal stations.

Current Transformers

- 120-Day General Inspection, the following is checked: bushings; tanks; oil leaks; rust/paint condition; concrete base; primary connections; conduits; cabinets; and grounding.
- Every six years the following is done:
  - Wiring connections checked;
  - Secondary connections checked;
  - Heater amperage checked;
  - Touch-up painting done, as required; and
  - Doble test performed.
- Current transformers are currently replaced based upon either:
  - Condition as determined through visual inspection for rust and leaks;
  - Condition as determined by Doble testing;
  - If the unit is suspected to contain PCBs > 50 ppm;
  - If the unit is a 230 kV IMBA; or
  - Age > 40 years.

Potential Transformers/Capacitive Voltage Transformers

- On 120-Day General Inspection, the following is checked: bushings; tanks; oil leaks; rust/paint condition; concrete base; primary connections; installed heater amperages; conduits; cabinets; voltages at each secondary winding; and grounding;
- Every six years the following is done:
    - Connections for position and tightness checked;
    - Grounding device checked;
    - Coupler box internally inspected;
    - Gaskets and gap clearances checked;
    - Heater amperage checked;
    - Touch-up painting done, as required;
    - Perform Doble test;
    - Surge protection device in capacitor voltage transformer junction box checked/tested, if fitted for wave-trap;
    - Ground switches cleaned and lubricated; and
    - Surge gap checked.
- Potential transformers and capacitive voltage transformers are currently replaced based upon either:
    - Condition as determined through visual inspection for rust and leaks;
    - Condition as determined by Doble testing;
    - If the unit is suspected to contain PCBs > 50 ppm; or
    - Age > 40 years

Surge Arresters

- 120-Day Power Transformer inspection, a visual inspection is performed; and
- Every six years, a visual inspection and a Doble Test are performed;
- Arresters are replaced for either of the following reasons:

- Doble Testing indicates a failed unit;
- Visual inspection identifies severe commination or insulator cracking;
- Arrester type is prone to failure;
- A transformer is being replaced (consideration will be given to installing arrester replacement); or
- Arrester 40 years old.

Disconnect Switches

- 120-Day inspection is completed, which includes: visual check for alignment and signs of overheating; insulator conditions; and heater;
- Annual Infrared scans to look for hot spots. The following guidelines shows temperature difference between phases and outlines response time required to address identified hot spots:

Priority	Temp. Difference (ΔT Phase to Phase)	Respond Within
1 (Emergency)	Visually Hot	24 Hours
2	Above 50°C	1 week
3	20°C to 50°C	1 month
4	Below 20°C	1 year

- Every six years (one or three years as well if located in severe environmental contamination) the following is checked: All connections and contacts; switch operation; contacts are greased; and linkages and operating mechanism are lubricated. On motor operated disconnect switches the motor operation is checked and if load break, interrupter modules are checked; and
- Disconnect switches are replaced based primarily on: condition and operating problems and issues as determined by issues found during PMs; problems encountered during operation; excessive corrective maintenance required; etc. Secondary prioritization for the long term plan is based on equipment age being at least 50 years.

Batteries and Chargers

- 120-Day inspection includes: voltmeter checks; ammeter checks; and visually checking battery condition as well as electrolyte levels for flooded cells. Distilled water may be added to flooded cells and completion of equalize charge procedure if required;

- Batteries and chargers are inspected and cleaned annually. During this inspection a conductance test is performed on all the cells and straps with a Midtronics battery tester. For flooded cells the specific gravity is also checked on all cells;
- Discharge testing is completed for all battery banks during factory acceptance testing and is scheduled to be completed on Criticality A and B flooded cell banks after 10 years of being in service and then every five years thereafter. Criticality A and B VRLA banks are discharge tested every two years; and
- Flooded Cell battery banks and chargers are recommended to be replaced after 20 years and VRLA batteries after ten years. Equipment condition and operating problems are also considered and equipment is replaced sooner if required.

Air Systems

- Compressor Annual PM: change deteriorated disposable parts; cleaning; record operational data; performance testing; protective device function testing, and visual inspection;
- Monthly Air System PM: cleaning; record operational data; performance testing; protective device function testing; and visual inspection; and
- Compressor overhauls: overhauls are based on the inspections performed, as well as experience. Factors considered for compressor overhauls are: excessive oil consumption; change in inter-stage pressure/back pressure; excessive time to bring system up to pressure; oil leaks; broken valve spring/overheating; excessive noise; and vibration, etc.

Many of the air systems have been upgraded prior to the decision to replace all air blast circuit breakers and as a result there is no longer a plan in place to replace air dryers or compressors. Any remaining compressors used in a different application will be assessed by the each for replacement.

Grounding

- 120-Day PM: visual inspection; and
- Grounding is upgraded as a result of visual inspections and grounding analysis completed in accordance with IEEE 80-2013.

Capacitor Banks

- 120-Day PM: record operational data, blown fuse replacement, and visual inspection; and
- Six-Year PM: record operational data, electrical testing (capacitance, insulation resistance), blown fuse replacement, cleaning, and visual inspection.

Hydro will plan replacement of capacitor banks based upon condition, or consider replacement as banks approach 45 years in service.

Synchronous Condensers

- Minor inspections, performed on year one and year two of a three year cycle, include:
  - Check/monitor operating parameters (bearing temperatures, vibration, etc.) prior to unit coming offline and after inspection (prior to being released back to service);
  - Drain oil system and sumps. Inspect oil sump, replace filters and refill. Run oil through filter press when refilling. Repair and/or report any issues. Replace any required gaskets;
  - Remove and Visually Inspect outer end covers and inner baffles including mounting hardware. Repair or note any issues;
  - Take oil samples before and after oil filtering;
  - Remove the bearing pedestal cap and top half of the bearing. Inspect and check clearance and cap pinch;
  - Inspect piping connections, oil fittings, oil flinger rings, bearing cap, upper half of the bearings;
  - Inspection of the fan blades and shrouds;
  - Check high pressure lift system. Take shaft lift measurements at start and after inspection before returning unit to service and check oil filters. Replace filters if required;
  - Verify speed sensor clearance by rotating unit by hand before returning to service;
  - Replace intake air filters;
  - Complete electrical tests on stator, rotor, and bearing pedestals including Insulation Resistance (IR), Polarization Index (IR) and rotor field pole voltage drop;
  - Visually inspect rotor V-blocks, pole windings and collars;

- Inspection of damper winding ring assembly for signs of movement, bolts loosening, or copper cracking;
- Tap-test stator wedges;
- Inspect surge caps and lightning arrestors;
- Inspect slip rings. Disassemble brush rigging and inspect and cleaning. Install new brushes, as required;
- Complete general cleaning and maintenance of components;
- Perform any required maintenance items identified for follow up on previous inspection; and
- Reassemble unit, test-run and complete vibration and other operational checks.

- Major inspections, performed on year three of a three year cycle, include:
  - Complete items performed as part of the scope of the minor inspection;
  - Pull rotor and inspect the rotor and stator (further details below);
  - Remove bottom halves of bearings and complete set of checks;
  - Clean inside bearing pedestals;
  - Replace thrust bearing and install new seals/gaskets; and
  - Drain oil from reservoir and check screens, replace if required.

Stator and rotor inspections, performed as part of the scope of the major inspections, include the following checks, as well as any additional items identified for follow up on previous inspections:

- Stator:
  - Complete a thorough inspection of Stator Including windings, frame, end covers, etc. Tap-test stator wedges;
  - Inspect frame hold down bolts, soleplates, grout and dowels for looseness or evidence of movement;
  - Check oil coolers for mechanical damage to tubes, corrosion and leakage;
  - Check for any evidence of fretting on stator frame;

- Visually inspect stator core for damage and looseness to laminations, dirt, oil, foreign obstacles, overheating and corona activity. Note findings and clean stator as required; and
- Clean Stator Core.

- Rotor:
    - Check Rotor V blocks, coil braces and coil tightness. Check for damage and erosion;
    - Check Rotor field poles for insulation fretting and migration;
    - Check Rotor Field coils for damage and signs of overheating;
    - Check Damper Bars and resistance rings for damage and tightness;
    - Clean Rotor; and
    - Check for looseness, vibration, or movement of assembling hardware. Check for improper locking or peening of locking devices.

Appendix B

2019 Terminal Station and Transmission Line Project Status

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Table B-1: Terminal Station Projects

Project Description	Status of 2019 Planned Construction Completion
In-Service Failures - Various Sites	Complete (See Note 1)
Replace Insulators – (MY19)[10]	Complete
Additions For Load – Distribution System (Wabush)	Complete
Upgrade Data Alarm Management (CO)[11] – Stony Brook	Complete
Implement T.S. Flood Mitigation – Springdale	(See Note 2)
Replace Transformer T1 – Buchans	Complete
Replace Mobile DC Power Systems – Various Sites	Complete
Upgrade Terminal Station For Mobile Substation – St. Anthony Airport	(See Note 9)
Replace 66kV Station Service Feed – Holyrood	Complete
Replace Substation - Holyrood	Complete
Upgrade Circuit Breakers (MY20)[12] – Various Sites	(See Note 3)
Upgrade Cables (SY19)[13] – Various Sites	Complete
Terminal Station Refurbishment and Modernization Various Sites (Carryover)	
• Replace Protective Relays	Complete
• Perform Grounding Upgrades	Complete
• Replace Disconnects	Complete
• Install Breaker Failure Protection	Complete
Terminal Station Refurbishment and Modernization Various Sites (Multi-Year 2019)	
• Replace Surge Arrestors	Complete
• Refurbish and Upgrade Power Transformers	(See Note 4)
• Replace Protective Relays	(See Note 5)
• Install Fire Protection in 230kV Stations – Western Avalon	Complete
• Perform Grounding Upgrades - HPD	Complete
• Replace Instrument Transformers	Complete
• Upgrade Breaker Failure Protection	(See Note 6)
• Upgrade Fault Recorders	Complete
• Upgrade 230kV Terminal Station – Wabush	(See Note 7)
• Upgrade Data Alarm Systems – Sunnyside	(See Note 8)
• Replace Disconnects	Complete

[10] MY19 represents a 2018-2019 multi-year project.
[11] CO is a project that was carried over from a previous year
[12] MY20 represents a 2019-2020 multi-year project.
[13] SY19 represents a single-year project planned for 2019.

Project Description	Status of 2019 Planned Construction Completion
Terminal Station Refurbishment and Modernization Various Sites (Multi-Year 2020)	
• Replace Surge Arrestors (SY19)	Complete
• Refurbish and Upgrade Power Transformers	(See Note 9)
• Replace Protective Relays	(See Note 9)
• Install Fire Protection in 230kV Stations – Oxen Pond	(See Note 9)
• Perform Grounding Upgrades	(See Note 9)
• Replace Instrument Transformers	(See Note 9)
• Upgrade Breaker Failure Protection	(See Note 9)
• Upgrade Fault Recorders (SY19)	(See Note 10)
• Upgrade 230kV Terminal Station – Wabush	(See Note 9)
• Upgrade Terminal Station Equipment Foundations (SY19)	Complete
• Upgrade Data Alarm Systems – Holyrood	(See Note 9)
• Replace Disconnects	(See Note 9)
• Upgrade Reclosing Circuit Breakers – Holyrood	(See Note 9)
• Insulator Replacement – Various Sites	(See Note 9)
• Refurbish Control Buildings – Various Sites	Complete
• Upgrade Transformer Paralleling – Western Avalon	(See Note 9)

Table B-2: Transmission Line Projects

Project Description	Status of 2019 Planned Construction Completion
Perform WPLM Program	(See Note 11)
Muskrat Falls to Happy Valley interconnection, transmission line build (year 1)	(See Note 12)
TL 267, environmental rehabilitation and project close out, from Bay d'Espoir to Western Avalon	Complete

Notes

1) In 2019, the Terminals In-Service Failures project executed three 230 kV circuit breaker replacements; four instrument transformer replacements; one 69 kV breaker overhaul; one station service transformer replacement; one 138 kV disconnect switch replacement; one air compressor replacement; and four surge arrestor replacements. Additionally, two spare non-standard instrument transformers were purchased for Churchill Falls.

2) As engineering progressed for the original project alternative to mitigate flood risk, it was determined that the estimated cost to build the flood berm in the original location exceeded the budget. This resulted in a pause on the project to re-evaluate project alternatives. A more cost effective location of the flood berm structure was identified and a new schedule has been developed. The project has resumed and will carry over for construction in 2020, following engineering and environmental assessment.

3) Six circuit breaker replacements planned for 2019 were moved to be included in a future project. Three circuit breaker replacements were completed from other planned years, along with seven originally planned for 2019, for a total of ten replacements completed in 2019. Five circuit breaker replacements planned for 2019 were moved to 2020. One circuit breaker refurbishment was completed in 2019.

4) Parsons Pond transformer T1 bushing replacements were deferred to 2020 under the MY20 Terminal Station Refurbishment and Modernization Project due to mobile substation issues that resulted in the cancellation of the planned outage. South Brook transformer T1 bushing replacements were cancelled because they did not contain PCBs. Material issues with some transformer bushing replacements caused deferrals to 2020 under MY20 Terminal Station Refurbishment and Modernization Project. Bay D'Espoir T10 bushing replacements were deferred to 2020, under MY20 Terminal Station Refurbishment and Modernization Project, due to unavailability of an outage. Hawke's Bay transformer T3 and Oxen Pond transformer T2 moisture reduction system installations were deferred to 2020 moved to MY20, under MY20 Terminal Station Refurbishment and Modernization Project, due to unavailability of contractor.

5) Several project scope items were carried over mostly due to unavailability of outages: Holyrood transformer T8 protection, Upper Salmon transformer T1 protection, Holyrood bus B11/B13 protection, Holyrood bus B12 protection, HRD transformer T10 protection, Bay D'Espoir transformer T10 protection and Bay D'Espoir generator G7 protection.

6) Work is carried over to 2020 due to insufficient engineering and field resources.

7) All work was completed in 2019 except one of the three breakers and its protection system. Upon review of the outage requirements for this work, it was agreed with IOCC to defer the work to 2020 when they could better manage the impact of the outage. A portion of the communications scope was also carried into 2020.

8) Delay in engineering completion and material procurement resulted in carryover into 2020.

9) No planned 2019 construction.

10) Moved to 2020 construction due to lack of field resources.

11) WR scope for WPLM was completed in 2019. The 2019 scope of work for the WPLM included the inspection and treatment of 2,351 poles and the replacement of approximately 32 poles, 7 sets of kneebracing, 26 cross arms, and 9 sets of cross bracing. Work that carried over into 2020 included the replacement of 7 poles across lines TL 220 (1 pole), TL 250 (2 poles), TL 251 (3 poles), and TL 252 (1 pole), and the replacement of 47 cross arms across lines TL 221 (9 cross arms), TL 226 (1 cross arm), TL 227 (1 cross arm), TL 229 (8 cross arms), TL 241 (1 cross arm), TL 250 (2 cross arms), TL 251 (4 cross arms), TL 252 (1 cross arm) and TL 253 (20 cross arms).

12) Line constructed but not placed in service in 2019.

Attachment 1

Terminal Station Asset Management Overview

LICENSED PROFESSIONAL ENGINEER
08906
MATTHEW P. HALLORAN
SIGNATURE
2019/07/22
DATE
NEWFOUNDLAND & LABRADOR

2020 Capital Budget Application
Terminal Station Asset Management Overview

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") has developed an ongoing capital program to replace or refurbish assets as they reach the end of their design life or require attention due to obsolescence or anticipated failure.

Before 2017, Hydro's terminal station projects could be divided into two categories: (1) stand-alone and (2) programs. Programs included projects that are proposed year after year to address the upgrade or replacements of deteriorated equipment, such as disconnects or instrument transformers, and have similar justification each year. Stand-alone would include projects that do not meet the definition of a program. Hydro has typically had as many as 15 separate program-type terminal station projects in its capital budget applications, with each program based upon a particular type of asset.

Starting with the "2017 Capital Budget Application" ("CBA"), Hydro implemented a change to how the terminal station projects are submitted for consideration by the Board of Commissioners of Public Utilities ("Board"). Hydro has consolidated the programs into the Terminal Station Refurbishment and Modernization project ("Project"), thereby improving regulatory efficiency and easing the administrative effort for both the Board and Hydro and allowing Hydro to look for opportunities to realize efficiencies by improving coordination of capital and maintenance work in terminal stations.

In 2019, Hydro submitted a revised Terminal Station Asset Management Overview ("Asset Management Overview") to provide an updated overview of Hydro's asset maintenance philosophies in one document. Hydro will submit the Project within annual CBAs going forward, proposing required terminal station work and referencing this Asset Management Overview document.

Contents

1.0 Introduction

Hydro has 70 terminal stations that contain electrical equipment such as transformers, circuit breakers, instrument transformers, disconnect switches, and associated protection and control relays and equipment required to protect, control, and operate Hydro's electrical grid.

Hydro's Asset Management System governs the life cycle of its terminal station assets. This system monitors, maintains, refurbishes, replaces, and disposes of assets with the objective of providing safe, reliable electrical power in an environmentally responsible manner at least cost. Within this system, assets are grouped such as breaker, transformers, grounding systems, buildings, and sites. This allows the asset managers to establish consistent practices for equipment specification, placement, maintenance, refurbishment, replacement, and disposal. These practices mean that the monitoring, assessments, action justifications for capital refurbishment and replacement for asset sustaining projects are consistent. Hydro established programs which enact these practices for groups or sub groupings of assets, for example High Voltage Switch Replacements.

Part of Hydro's annual capital program is a sustained effort to ensure the safety and reliability of terminal station assets. Historically, the Board's approval for this effort has been requested by Hydro submitting either individual projects for particular assets, or programs for Station sustaining work in its CBA. This approach can result in a segmented view of the expenditures to sustain Station assets. For example in the 2016 CBA, there were 15 separate program-type projects submitted. The expenditures detailed in these projects according to the Board's classifications are normal capital expenditures. This situation provides an opportunity to increase regulatory efficiency.

With the 2017 CBA, Hydro consolidated planned terminal station sustaining work into the Project. Additionally, Hydro submitted a project titled "Terminal Station In-Service Failures" to cover the replacement or refurbishment of failed equipment, or incipient failures. Hydro is utilizing the Asset Management Overview as a reference for both projects to streamline and focus information submitted. The Asset Management Overview provides supporting information which was, historically, annually presented for similar classification projects in the CBA. The remainder of this document provides information as to the assets involved, an overview of each asset program, and how this document will be updated in the event of changes to Hydro's asset management philosophies.

Hydro will provide an updated Asset Management Overview as it implements changes to its asset management philosophies appropriate for inclusion in the Asset Management Overview.

1.1 Changes in Version 4

Hydro submits Version 4 of this document with the 2020 CBA. All material updates in this version are shaded in grey, and are summarized below:

- Addition of section 4.1.11: Replace Station Lighting;
- Addition of age-based replacement criteria for instrument transformers;
- Addition of hot oil dry-out as a means of addressing high moisture content for power transformers;
- Extension of the 2016–2020 Circuit Breaker Replacement Program to 2022;
- Addition of 66 kV breakers to 20-year refurbishment requirement for SF_6 circuit breakers
- Place a hold on plans for breaker bypass switches; and
- Addition of replacement of breaker failure protection upgrades in 230 kV stations for breaker failure protection.

Minor changes to syntax have been made to improve readability. These minor changes have not been shaded.

2.0 Background

2.1 Newfoundland and Labrador Hydro's Terminal Stations

Terminal stations play a critical role in the transmission and distribution of electricity. Terminal stations contain electrical equipment, such as transformers, circuit breakers, instrument transformers, disconnect switches, and associated protection and control relays and equipment required to protect, control, and operate the Hydro's electrical grid. Stations act as transition points within the transmission system, and interface points with the lower voltage distribution and generation systems. Hydro has 70 terminal stations throughout Newfoundland and Labrador.

2.2 Terminal Station Infrastructure

Stations contain the following infrastructure, which is described throughout this report:

- Transformers;
- Circuit breakers;
- Instrument transformers;
- Disconnect, bypass, and ground switches;
- Surge arresters;
- Grounding;
- Buswork;
- Steel structures and foundations;
- Insulators
- Control buildings;
- Protection and control relays;
- Yards, fences, and access roads;
- Battery banks; and
- Terminal station lighting

Many of Hydro's terminal stations were constructed in the 1960s. Annual capital commitment is needed to sustain terminal station assets to ensure that Hydro can continue to provide customers with reliable electrical service.

3.0 Terminal Station Capital Projects

3.1 Historical Terminal Station Capital Projects

In the 2016 CBA there were 22 individual terminal station projects which accounted for $30 million, or 16% of the capital budget. Historically, Hydro’s terminal station projects were divided into two categories: (1) stand-alone and (2) programs. Programs include projects that are proposed year after year to address the required refurbishment or replacement of assets such as disconnects or instrument transformers, and have similar justification and other information presented each year. Of the 22 individual terminal station projects proposed in 2016, 15 were program-type projects. In the 2017 CBA, Hydro consolidated the historical station projects into the Project.

3.2 Hydro's Approach to Terminal Station Capital Project Proposals

The programs now included in the Project are:

- Upgrade Circuit Breakers (Beyond 2020);
- Replace Disconnect Switches;
- Install Fire Protection ;
- Replace Surge Arresters;
- Upgrade Terminal Station Foundations;
- Refurbish Control Buildings;
- Replace Station Lighting;
- Replace Battery Banks and Chargers;
- Upgrade Terminal Station for Mobile Substation;
- Install Breaker Bypass Switches;
- Protection and Control Refurbishment and Upgrades;[1]

The Project excludes:

- Transformer replacement and spares: although transformer replacement fits within the description of a terminal station program, these projects often have unique justification and a high project cost and, therefore, are proposed separately.
- Accelerated circuit breaker replacement: Hydro proposed the accelerated replacement of 230 kV circuit breakers as part of the 2016 CBA "Upgrade Circuit Breakers" project. This project involves the replacement of high-voltage circuit breakers through the year 2020 and is now moved to 2022. As this project has already been approved, it is not included in the Project.

[1] As noted in the 2017 version of the Asset Management Overview, the 2016 Upgrade Terminal Station Protection and Control Upgrade, Upgrade Protective Relays, Upgrade Fault Recorders, Upgrade Data Alarm Systems and Install Breaker Failure Protection projects were combined in the Asset Management Overview and the Project as the Protection and Control Refurbishment and Upgrades Program.

However, future breaker replacements not captured in the 2016–2020 "Upgrade Circuit Breakers" project will be included in future CBAs, and, therefore, the justification for such programs is included in this report.

- Activities which cannot be scheduled for inclusion in a CBA as these will be submitted as either supplemental to the CBA or executed in the Terminal Stations In-Service Failures project.
- Activities in response to additional load or reliability requirements. As these projects generally have unique justification, and will be proposed separately.
- Activities in response to significant isolated issues in a particular station, such as replacement of a failed power transformer. As these projects generally have unique justification, the projects will be proposed separately.

Hydro continues to maintain individual records with regards to asset capital, maintenance, and retirement expenditures and performance, which will be queried to support the development of the annual capital plan.

This document is submitted to the Board as part of the 2020 CBA. Hydro will annually submit proposals for the Terminal Station Refurbishment and Modernization project and Terminal Station In-Service Failures project referencing the most recent Asset Management Overviews. Future CBAs will not include a copy of the Asset Management Overview unless Hydro revises its contents. When the Asset Management Overview is revised, Hydro will clearly denote such changes, highlighted in gray, for review and approval by the Board.

3.3 Benefits of This Approach

As supporting information for programs changes infrequently, referencing the Asset Management Overview in the Project documentation will eliminate the preparation and review of repetitious information. Hydro estimates that this approach could save up to $120,000[2] annually, not including time and costs for review by the Board and Intervenors.

[2] If the work undertaken in the 2017 Terminal Station Refurbishment and Modernization project had been submitted as 12 individual projects, it is estimated preparation would be approximately $10,000 per project.

Hydro has a proactive Asset Management System which strives to anticipate future failures so that refurbishment or replacement can be incorporated into a CBA. However, there are situations were immediate refurbishment or replacement, which has not be included in an CBA, has to be undertaken due to the occurrence of an unanticipated failure or the recognition of an incipient failure so as to maintain the delivery of safe, reliable electricity at least cost. These situations seldom include extenuating or abnormal circumstances and costs. With aging terminal station assets unanticipated failures may increase. This increase will require additional future efforts to provide and review regulatory documentation. By introducing a Terminal Station In-Service Failures project, there will be a reduced need for that documentation and change management processes. Each year, Hydro will provide a concise summary of the previous year's work.

Hydro expects the Project will provide opportunities whereby Hydro can further optimize capital and maintenance work so as to minimize outages to customers and equipment as personnel look to further coordinate work by location.

4.0 Asset Management Programs

4.1 Electrical Equipment

4.1.1 High-Voltage Instrumentation Transformer Replacements

The metering protection and control devices such as protective relaying, power quality monitors, and kWh meters used in generation and transmission systems are not manufactured to handle the currents and voltages inherent to those systems. Measurement of the electricity's currents and voltages are provided to these devices through a CT and a PT respectively. CTs and PTs are collectively known as instrument transformers. Hydro has approximately 900 individual high-voltage instrument transformers within the Island and Labrador Interconnected Systems.

A high-voltage Instrument Transformer consists of an insulated electrical primary and secondary winding, tank, and bushing components. The insulation system involves the use of insulating oil or dry type insulation and a high-voltage porcelain bushing which allows the safe connection of the winding to high-voltage conductors. The winding is enclosed in a steel tank.

Figure 1: 69 kV CT (Left) and PT (Right)

Hydro manages planned budgeted Instrument Transformer replacements in four categories:

1) Condition
2) PCB Compliance Replacements
3) Manufacturer and model (not required after 2019)
4) Age

Condition

Deterioration or damage to the various Instrument Transformer components can result in the failure of the unit to provide accurate measurements to metering, protection, and control devices, which may affect the safe and reliable operation of the generation and transmission systems. Failure could also result in an oil spill. Also, in some situations pieces of the Instrument Transformer may be forcibly projected resulting in a safety risk for personnel in the area, or damage to other infrastructure.

Damage to an Instrument Transformer normally results from vandalism, impacts from catastrophically failed equipment, or accidental contact of mobile equipment. Upon such incidents, Hydro assesses the electrical and physical integrity of Instrument Transformer to determine if replacement is required.

Hydro monitors instrument transformers for physical and electrical deterioration by conducting regular visual inspections of the units as part of its station inspection program plus regularly scheduled station infrared inspections and electrical insulation testing.

Physical deterioration involves conditions such as oil leaks, rusting, or small chips and cracks in the insulation. Figure 2 shows an example of rusting on a PT tanks.

Figure 2: Rusting PT

Electrical deterioration is identified by conducting power factor testing at intervals which is used to establish the rate and level of insulation degradation. Hydro uses Doble Engineering Company to provide assistance with assessment of the test results as required.

On an ongoing basis, Hydro's asset management personnel review the unit deterioration information and determine when corrective maintenance or unit replacement is required. Hydro conducts minor Instrument Transformer corrective maintenance such as painting and small bushing chip treatment. External services to economically undertake major corrective maintenance or unit refurbishments do not exist, so units requiring major corrective maintenance or refurbishments are replaced.

PCB Compliance Replacements

Environment Canada's polychlorinated biphenyl ("PCB") Regulations requires that by 2025 all instrument transformers will not have a PCB concentration greater that 50 mg/kg. Instrument transformers are sealed oil filled units, where the oil, which acts as an electrical insulator, has been known to contain PCBs for equipment prior to 1985. Due to the age of the units and the risk of introducing contamination such as air into the unit, which could impact the electrical integrity of instrument transformers, Hydro does not sample instrument transformers. Therefore, establishing the actual PCB concentration in an Instrument Transformer is not possible. Hydro, in consultation with manufacturers, has established that units manufactured before 1985 are suspected to contain PCBs in concentration levels greater than or equal to 50 mg/kg. Thus Hydro has a program to replace all suspect oil-filled instrument transformers before 2025.

Manufacturer and Model

In 2010 Hydro experienced a failure of a 230 kV ASEA IMBA Current Transformer. The failure analysis recommended this manufacturer and model be replaced over time. These replacements are included in this program. The last of these replacements was completed in 2019 and hence this criterion will be removed from this program.

Age

Hydro targets replacement at 40 years of age to reduce the risk of in-service failures and minimize service interruptions. Original Equipment Manufacturers ("OEM") recommend that the life of an instrument transformer is approximately 30 to 40 years. Recent in-service failures occurred between 20–39 years of life (three of which occurred between 29–39 years of life).

Exclusions from Instrument Transformer replacement program

Modern-day circuit breaker technology includes CTs embedded in the circuit breaker bushings. Therefore, where possible, external CTs will be displaced by bushing CTs as circuit breakers are replaced, and such CTs are not included in this program.

4.1.2 High-Voltage Switch Replacements

High-voltage switches are used to isolate equipment either for maintenance activities or for system operation and control (disconnect switches). Switches are also used to bypass equipment to prevent customer outages while work is being performed on the equipment. Disconnect switches are an important part of the Work Protection Code as they provide a visible air gap (i.e., visible isolation) for utility workers. Work protection is defined as "a guarantee that an ISOLATED, or ISOLATED and DE-ENERGIZED, condition has been established for worker protection and will continue to exist, except for authorized tests." Proper operation of disconnect switches is essential for a safe work environment and for reliable operation.

The basic components of a disconnect switch are the blade assembly, insulators, switch base and operating mechanism. The blade assembly is the current carrying component in the switch and the operating mechanism moves it to open and close the switch. The insulators are made of porcelain and insulate the switch base and operating mechanism from the current carrying parts. The switch base supports the insulators and is mounted to a metal frame support structure. The operating mechanism is operated either manually, by using a handle at ground level to open and close the blade, or by a motor operated device, in which case the switch is known as a motor-operated disconnect. A disconnect and its associated components are shown in Figure 3.

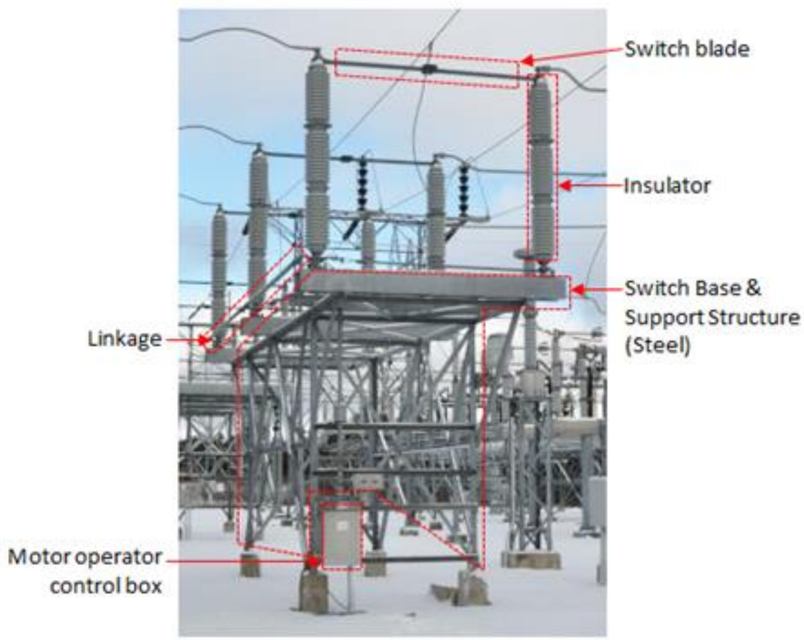

Figure 3: Various Components of a High-Voltage Disconnect Switch

Hydro monitors the condition of its switches by conducting regular visual inspections of the units as part of its station inspection program and its infrared inspection program and by reviewing reports from the

JDE E1 work order system or staff who operate the switch, outlining problems such as inoperable mechanical linkages, misalignment of switch blades, broken insulators, and seizing of moving parts. Asset management personnel determine the timing of corrective maintenance or switch replacement. If the required parts are available then repairs are undertaken as part of on-going maintenance. Switches that have operating deficiencies and have reached a service life of 50 years or greater are designated for replacement. Switches that have no replacement parts available due to obsolescence, damaged beyond repair, or cannot be economically repaired and do not require immediate replacement are designated for replacement under this program.

Figure 4 shows an example of a badly damaged disconnect switch.

Figure 4: Broken Insulator on 69 kV Disconnect Switch

4.1.3 Surge Arrester Replacement

Surge arresters (also known as lightning arresters) are used on critical terminal station equipment to protect that equipment from voltage due to lightning, extreme system operating voltages, and switching transients, collectively called “overvoltages.” In these situations, voltage at the equipment can rise to levels which could damage the equipment’s insulation. The surge arresters act to maintain the voltages within acceptable levels. Without surge arresters, equipment insulation could be damaged and faults could result during overvoltages. Hydro typically has surge arresters installed on the high side and low voltage sides of power transformers rated 46 kV and above.

Figure 5 shows the arresters on a 230 kV power transformer.

Figure 5: Western Avalon Terminal Station Transformer T3 230 kV Surge Arresters

Surge arresters can fail because of the cumulative effects of prolonged or multiple overvoltages. When a surge arrester fails, it is not repairable and must be replaced immediately otherwise the major equipment maybe exposed to damaging overvoltages. The older arrester designs have a higher incidence of failure than the newer designs.

Hydro’s surge arrester asset management program replaces surge arresters based upon the following criteria:

- Removal of gapped type arresters with zinc oxide design due to enhanced performance;
- Replacement of units due to a condition identified through visual inspections for chips or cracks or electrical testing such as power factor testing;

- If failures occur on a given transformer, all arresters on both the high and low side are considered for replacement either immediately or in a planned fashion; and
- If transformers are being planned for maintenance or other capital work, consideration is given to changing aged arresters on a common outage. Hydro targets replacement at 40 years of age, to reduce the risk of in-service failures and minimize service interruptions.

4.1.4 Insulator Replacement

Insulators provide electrical insulation between energized equipment and ground.When an insulator fails and a fault occurs, a safety hazard and/or customer outages may occur.

Insulators consist of insulating material such as glass, porcelain and metal end fittings to attach the insulator to the structure and the conductor. The metallic hardware is mated with the porcelain or glass insulator using cement. There are different styles of insulators. An example of a station post insulator is shown in Figure 6.

Terminal stations contain post type, cap and pin-top, multi-cone, and suspension type insulators.

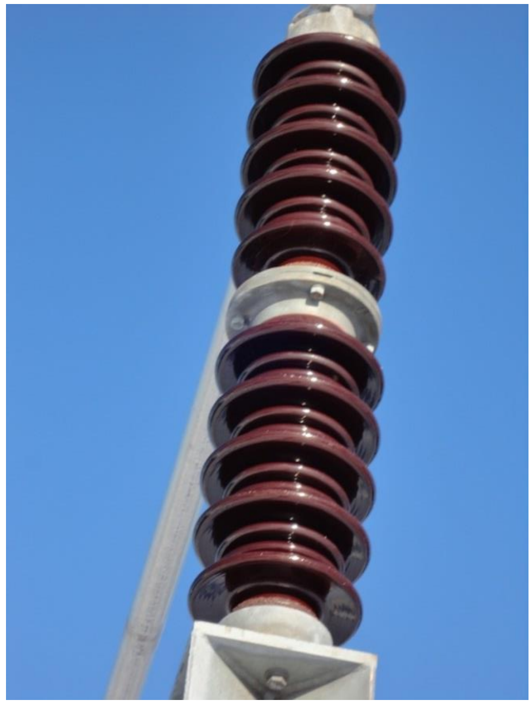

Figure 6: Multi-Cone Type Insulator Prone to Failure due to Cement Growth

For insulators using porcelain, cement is used in mating the porcelain and metal hardware. Some older insulators have been damaged by a phenomenon known as cement growth. This is a common problem in the utility industry. In such situations, water is absorbed into the concrete, during freeze/thaw cycles, causing swelling of the cement placing stress upon the porcelain. Over time, the increasing pressure caused by cement growth will crack or break the porcelain resulting in insulator failure. In such situations, porcelain may fall presenting a safety hazard to crews or damaging equipment below. Also faults resulting in outages to customers often occur, when insulator failure leads to flash-over. Some time ago, insulator manufacturers identified and researched cement growth problems and have improved their cement quality to eliminate this problem.

Hydro carries out detailed insulator surveys by geographical area. Hydro identifies any insulator types known to be prone to failure due to cement growth, and replaces these insulators under this program.

4.1.5 Grounding Refurbishment and Upgrades

The grounding system in a terminal station or distribution substation consists of copper wire used in the ground grid under the station, gradient control mats for high-voltage switches, and bonding wiring connecting the structure and equipment metal components to the ground grid. In the event of a ground fault, electrical potential differences will exist in the grounding system. If the grounding system is inadequate or deteriorated these differences may be hazardous to personnel. These potential differences are known as step and touch potentials. Effective station grounding reduces these potentials to eliminate the hazard.

Figure 7: Typical Grounding Connection on Terminal Station Fence

To determine whether grounding upgrades are required, Hydro performs a step and touch potential analysis of the terminal station or distribution substation. Step and touch potential analysis involves the gathering of field data and conducting analysis in order to determine if ground grid modifications are required to eliminate step and touch potential hazard. This engineering is conducted in accordance with the Institute of Electrical and Electronics Engineers ("IEEE") Standard 80-2000. Grounding systems with hazardous step and/or touch potentials are upgraded, by adding additional equipment bonding, gradient control mats, or copper wire to the station grounding grid. In the case where the terminal station grounding infrastructure has deteriorated with age, or is damaged due to accidental contact or vandalism, the grounding system is refurbished by repairing damage or replacing missing infrastructure. Upgrades and refurbishments are made in accordance with Hydro's Terminal Station Grounding Standard.

4.1.6 Power Transformer Upgrades and Refurbishment

Power transformers are a critical component of the power system. Transformers allow the cost-effective production, transmission, and distribution of electricity by converting the electricity to an appropriate voltage for each segment of the electrical system and allow for economic construction and operation of the electrical system.

Hydro has over 130 power transformers 46 kV and above, as well as several station service transformers at voltages lower than 46 kV.

The basic components of a power transformer are:

- Transformer steel tank containing the metal core and paper insulated windings; oil which is part of the insulating system, and a gasket system which keeps the oil from getting into the environment;
- Bushings mounted to the top of the transformer tank, which connects the windings to the external electrical conductors;
- Radiators and cooling fans, which remove heat for the transformer's internal components;
- On-Load tap changer, which is a device attached internally or externally through which transformer voltages are maintained at acceptable levels; and
- Protective devices to ensure the safe operation of the transformer, such as gas detector relays, oil level and temperature relays, and gauges.

Figure 8 shows a picture of a 75 MVA, 230/66 kV power transformer at the Hardwoods Terminal Station.

Figure 8: Power Transformer

Transformers are expensive components of the electrical system. Hydro, like many North American utilities, is working to maximize and extend the life of its transformer by regularly assessing their condition; executing regularly schedule maintenance and testing and undertaking refurbishment or corrective actions as required. Transformers regularly undergo visual inspection as part of Hydro's terminal station inspection and scheduled preventive maintenance and testing, to identify concerns regarding a the following transformer conditions:

- Insulating oil and paper deterioration;
- Oil moisture content;
- Oil leaks;
- Tank, radiators, and other component rusting/corrosion;

- Tap changer component wear or damage;
- Damaged/Deteriorated and PCB contaminated bushings;
- Failure of the protective devices; and
- Cooling fan failures.

Details on the assessment procedures and corrective action for each of these concerns are provided below.

Transformer Oil Deterioration

The insulating oil in a transformer and its tap changer diverter switch is a critical component of the insulation system. Normal operation of a transformer will cause its oil to deteriorate. Deterioration results from a number of causes such as heating, internal arcing of electrical components, or ingress of water moisture into the transformer. Deterioration of the oil will affect its function in the insulation system and may damage the paper component of the insulation system. Unacceptable levels of deterioration can affect the reliable operation of the transformer. To ensure that the oil in a transformer is of an acceptable quality, Hydro has an oil monitoring program, in which an oil sample is obtained annually from each transformer and analyzed by a professional laboratory. The test results are assessed to determine the level of deterioration. If an unacceptable level of deterioration is identified, required corrective action is identified by asset management personnel. This action entails either the refurbishment of the oil to improve its quality or the replacement of the oil.

Moisture Content

Oil samples are also analyzed to determine their moisture content. Moisture in a power transformer may be residual moisture, or may result from the ingress of atmospheric moisture. Oil and insulating paper with high moisture content has a reduced dielectric strength, and therefore its performance as an electrical insulator is diminished. To address transformers with high moisture content, Hydro will either install an online molecular sieve dry-out system (which circulates and dries the transformer oil without requiring an equipment outage) or perform a hot oil dry-out (which circulates and dries the transformer oil and requires an equipment outage).

Oil Leaks and Corrosion

Transformer oil leaks are an environmental hazard and as oil is part of the insulation system, unchecked leaks can affect the safe and reliable operation of a transformer. Leaks can be caused by a number of factors, including failed gaskets or severely corroded radiators, tank piping and other steel components. Transformers are visually inspected for leaks as part of the regularly scheduled terminal station inspection program and assessed by asset management personnel to determine the level of corrective action. Minor action, such as small repairs, patching, and minor painting is undertaken as part of the maintenance. Work requiring major refurbishments and replacements such as radiator or bushing replacements, gasket replacements and tank rusting refurbishment are undertaken under this program.

On-Load Tap Changer

On-Load tap changer diverter switches, which are externally mounted on the tank, adjust the voltage by changing the electrical connection point of the transformer winding. This involves moving parts, which are subject to wear and damage. Additionally, in older non-vacuum designed diverter switches, arcing occurs during the movement, leading to deterioration of the insulating oil. This wear and deterioration can lead to failure of the tap changer. Oil testing techniques have been developed by professional laboratories which provide assessments of the condition of the parts and oil. Oil samples are obtained annually from each on-load tap changer to perform a Tap Changer Activity Signature Analysis by the laboratory. This analysis provides a condition assessment of the tap changer oil and components. Hydro typically implements the laboratory’s sampling interval recommendations. This ranges from continued or increased annual sampling, planned refurbishment, or immediate removal from service, inspection, and repair. The latter two activities are covered by this project. Another component covered by this project is to correct leaking seals between tap changer diverter switches and the transformer main tank. Currently Hydro has several transformers that show low levels of combustible gases such as acetylene, due to gasses migrating from the tap changer diverter switch compartment to the main tank.

Bushings

In addition to the aforementioned leaking bushings, Hydro must also address suspected bushings to have PCB levels not compliant with the latest PCB regulations, as well as bushings with degraded electrical properties.

The latest regulations state that all equipment remaining in service beyond 2025 must have a PCB concentration of less than 50 mg/kg. Hydro has approximately 450 sealed bushings that were manufactured prior to 1985 which are suspected to contain PCBs greater than 50 mg/kg. Some sealed bushings have sampling ports to allow sampling; however, Hydro does not sample due to small quantity of oil in bushings and the risk of contamination during sampling. Bushings which are known or suspected of having unacceptable PCB levels are replaced.

Hydro performs Power Factor testing on bushings every six years as part of the transformer preventive maintenance. When Power Factor results indicate unacceptable electrical degradation, bushings are scheduled for replacement.

Protective Devices and Fans

Protective devices and cooling fans are tested during visual inspections and preventive maintenance, and are replaced when they fail to operate as designed or their condition warrant replacement. In addition, cooling fans are added where additional cooling is required due to increased loads.

Online Oil Analysis

In addition to oil quality, dissolved gas analysis (“DGA”) is performed on oil. DGA analyzes the levels of dissolved gases in oil, which provides insight into the condition of the transformer insulation. The presence of gases can indicate if the transformer has been subjected to fault conditions or overheating, or if there is internal arcing or partial discharge occurring in the windings. The annual oil sample test can only provide an analysis of transformer condition at the time when the sample is taken. In 2015, as part of this program, Hydro began installing online dissolved gas monitoring on generator step-up (“GSU”) transformers, to allow real-time, continuous monitoring of dissolved gases in oil. This continuously monitors the transformer and provides early fault detection. Continuous data is also a useful tool for personnel to use to trend gases to help schedule repairs or replacement prior to in-service failures, improving the overall reliability of the Island Interconnected System. Continuous monitoring enables Hydro to reduce unplanned outages and lessen the probability of equipment in-service failure.

This program was extended to non-GSU transformers in 2017, with online DGA being installed on critical power transformers on the Island Interconnected System. The factors used to determine the criticality score were submitted to the Board in the June 2, 2014 “Transformers Report.”[3] Hydro has identified 49 transformers for installation of online DGA devices between 2019 and 2024.

[3] Newfoundland and Labrador Hydro “Report to the Board of Commissioners of Public Utilities Regarding Work to be Performed on Transformers,” July 2, 2014.

4.1.7 Circuit Breaker Refurbishment and Replacements

The circuit breaker is a critical component of the power system. Located in a terminal station, each circuit breaker performs switching actions to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of circuit breakers through its fast response and complete interruption of current flow is essential for the protection and stability of the power system. The failure of a breaker to operate as designed may affect reliability and safety of the electrical system resulting in failure of other equipment and the occurrence of an outage affecting more end users. Hydro has over 200 terminal station circuit breakers in service with a voltage rating of 46 kV or greater.

Currently, Hydro maintains three different types of high-voltage circuit breakers:

1) Air blast circuit breakers ("ABCB"): use high-pressure air to interrupt currents and will be at least 38 years old at replacement. In the 2016 CBA Upgrade Circuit Breakers – Various Sites project, approval was obtained to replace ABCBs on an accelerated schedule by the end of 2020. This work is covered under a separate project and is not part of the work outlined in the Asset Management Overview. Hydro has since modified this program and is targeting completion in 2022.
2) Oil circuit breakers ("OCB"): use oil to interrupt currents and will be at least 36 years old at replacement. In the 2016 CBA Upgrade Circuit Breakers – Various Sites project, approval was obtained for the replacement of 10 OCBs up to 2020 which were not compliant with Environment Canada's PCB regulations. Hydro has since modified this program and is targeting completion of that scope in 2022. The remaining non-compliant breakers will be replaced before 2025. From 2017, any replacements not previously approved in the 2016 CBA will be included in the work conducted under this section of the Asset Management Overview.
3) Sulphur hexafluoride ("SF_6") circuit breakers: use SF_6 gas to interrupt current and installation of these breakers started in 1979 and continue for all new installations. In the 2016 CBA Upgrade Circuit Breakers – Various Sites project, approval was obtained, until the end of 2020, for the mid-life refurbishment and replacement of SF_6 circuit breakers with voltage rates 66 kV and above. From 2017, any SF_6 replacements and refurbishments not previously approved in the 2016 CBA will be included in the work conducted under this section of the Asset Management Overview.

Figure 9: Circuit Breakers: ABCB (Left), Oil (Middle), and SF_6 (Right)

As presented in the 2016 CBA, Upgrade Circuit Breakers – Various Sites project, SF_6 circuit breakers rated at 138 kV and above are required to be refurbished after 20 years of service. In 2018 Hydro added 66 kV-rated breakers to also be refurbished after 20 years. Replacement of SF_6 circuit breakers rated at 66 kV and above will be after 40 years of service, as is consistent with Hydro's philosophy, most recently presented to the Board in the 2016 CBA Upgrade Circuit Breakers – Various Sites project. Some SF_6 circuit breakers may require replacement before the 40-year service life period based upon their condition and operational history. Hydro expects to replace up to six breakers per year beyond 2020 and an average of five breakers and overhaul one breaker per year for 2022 and 2023 and not require overhauls again until beginning 2030. As per the 2016 CBA, "Upgrade Circuit Breakers – Various Sites" project, Hydro does not currently overhaul breakers rated below 138 kV.

Figure 10 shows the age distribution of circuit breakers not approved for replacement prior to 2017.

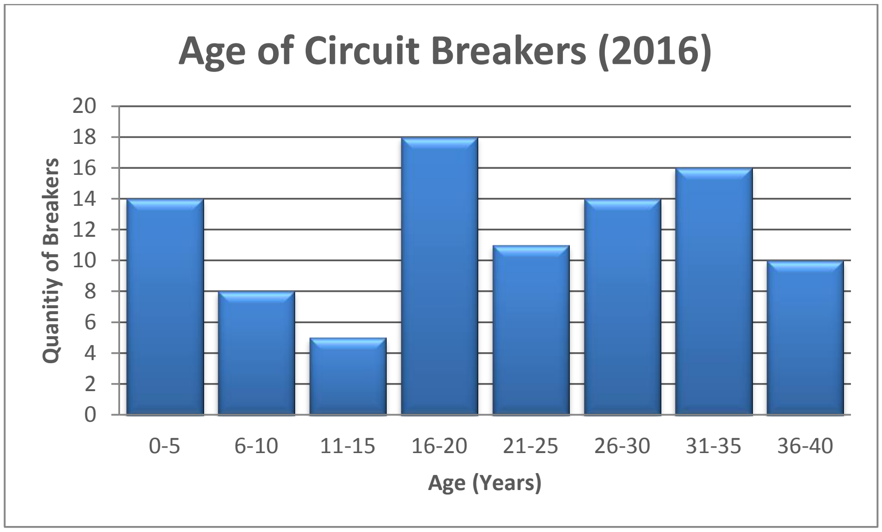

Figure 10: Age of Circuit Breakers not Included in Ongoing Replacement Program

4.1.8 Station Service Refurbishment and Upgrades

The power required to operate the various terminal station and distribution substation, collectively referred to as “station” equipment and infrastructure, is provided by the Station Service System. The station service system provides ac and dc power to operate the equipment in a station.

The ac station service is generally supplied by one or more transformers in the station. Due to their criticality, 230 kV terminal stations have a redundant station service feed, feed either through a redundant transformer tertiary, supplied from Newfoundland Power’s electrical system where available, or by a diesel generator. Common ac station service loads are:

- Transformer cooling fans;
- Anti-Condensation heaters;
- Station lighting;
- Control building HVAC;
- Control building lighting;
- Air compressors; and
- Battery chargers.

The dc station service is supplied by a battery bank which is charged from the ac station service. The dc station service provides power to critical devices in the station, and is designed to allow operation of the station in the event of an ac station service failure. Hydro's dc station service system is a 125 V system in the majority of the stations with some lower voltage stations and telecommunications equipment having 48 V systems. Common DC station service loads are:

- Circuit breaker trip and close circuits and charging motors;
- Protection relays;
- Emergency lighting;
- Disconnect switch motor operators for local/remote operation; and
- Telecommunications equipment.

As terminal station equipment is replaced, added, or upgraded, the ac and dc station service loads may increase. Upon the installation of new equipment in the terminal station, Hydro carries out a station service study to determine the loading on the station service system. In the event that the new station service loads exceed the design load of the system, upgrades such as cable, circuit breaker panel, splitter, and transfer switch replacements or additions are required. Replacement of station service transformers is not included in this program, as they are addressed separately in the CBA, under the Replace Power Transformers project, if required.

4.1.9 Battery Banks and Chargers

Battery banks and their chargers supply dc power to critical station infrastructure such as circuit breakers, protection and control relays, disconnect switch motor operators, and telecontrol equipment. Battery banks are designed to provide a minimum of eight hours of auxiliary power to critical infrastructure in the event of a loss of ac station service supply. The majority of Hydro's battery banks consist of lead-acid flooded-cell type batteries, whose capacity deteriorates over time. Hydro currently completes discharge testing on criticality A and B battery banks and will plan replacements if the battery bank's capacity has fallen to 80% or less of its rated capacity. Also, due to the critical nature of battery banks, flooded cell batteries are replaced after 20 years while valve-regulated lead-acid batteries are replaced after 10 years.

Figure 11: 125 Vdc Terminal Station Battery Bank

4.1.10 Install Breaker Bypass Switches

High-voltage circuit breakers, with their associated protection and control equipment, are used to control the flow of electrical current to ensure safe and reliable operation of the electrical system. When a breaker is removed from service for maintenance, troubleshooting, refurbishment, or replacement, an alternate electrical path must be implemented to avoid customer outages. On radial systems,[4] this alternate path is accomplished using a bypass switch. When closed, the bypass switch allows electricity to flow around the breaker allowing the breaker to be safely de-energized, while maintaining service continuity.

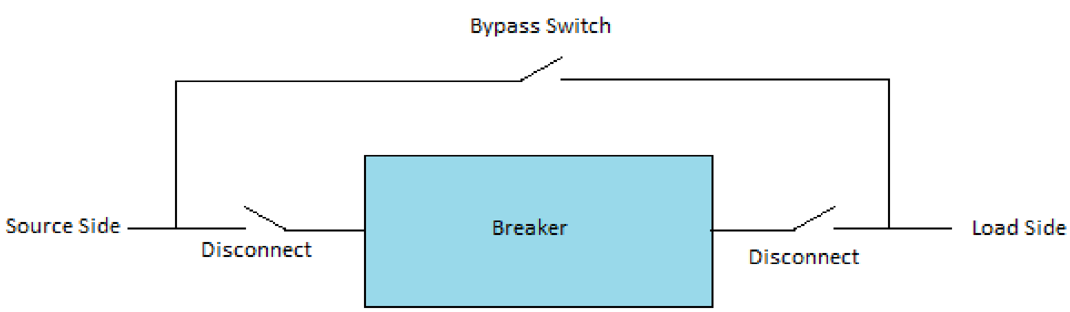

Figure 12: Example of Bypass Switch Installation

[4] A radial system is an electrical network that has only one electrical path between the source and the load.

Listed in Table 1 are six radial systems, servicing multiple customers, where breakers are installed without bypass switches. In order to ensure service continuity during breaker downtime, Hydro is considering installation of breaker bypass as noted in Table 1.

Table 1: Circuit Breakers Without Bypass Switches

Breaker Location	Customers Affected
Bottom Waters L60T1	2253 Bottom Waters area customers
Buchans B2T1	665 Buchans area Newfoundland Power customers and Duck Pond Mine
Doyles B1L15	3563 Grand Bay, Port aux Basques, and Long Lake area Newfoundland Power customers.
Howley B1T2	773 Hampden and Jackson's Arm area customers and 665 Newfoundland Power Howley area customers
Peter's Barren B1L41	1900 Great Northern Peninsula customers north of Daniel's Harbor
South Brook L22T1	2340 South Brook area customers.

Hydro put a hold on this program in 2018 and is looking closer at only doing this work when other major terminal station work is planned or there is a low cost solution.

4.1.11 Replace Station Lighting

Terminal station lighting is essential to provide adequate illumination for a safe working environment, as well as for deterring theft and vandalism in terminal stations. Hydro utilizes a variety of lighting technologies and configurations, depending on the application and vintage of the lighting system. Over time, exposure to the elements can cause physical deterioration, such as corrosion, leading to moisture ingress which impacts the function of the lighting system. Also some legacy lighting technologies have become obsolete.

Under this program, Hydro will replace deteriorated lighting systems as they become unable to provide adequate illumination of the terminal station and have become obsolete or beyond repair. Hydro will replace legacy lighting systems with modern, efficient lighting technologies whenever possible.

Figure 13: Corroded Ballast Requiring Replacement

Figure 14: Light Fixture Showing Perforations due to Corrosion, Enabling Moisture Ingress

4.2 Civil Works and Buildings

4.2.1 Equipment Foundations

Reinforced concrete foundations support high-voltage equipment and structures in Hydro's terminal stations. The majority of these structures formed part of the original station construction and support critical terminal station equipment and buswork.

The service life of galvanized steel structures varies depending on the operating environment, but can exceed 100 years, outliving the foundations on which they are built. A number of the foundations in Hydro terminal stations have deteriorated significantly due to repeated exposure to damaging freeze/thaw cycles, weathering, and age, leading to concerns over their integrity. Examples of degraded structure foundations are shown in Figure 15 and Figure 16.

Figure 15: Structure B1T1 Bottom Brook Terminal Station

Figure 16: Structure L01L37-1 Western Avalon Terminal Station

To ensure foundations perform as per the original design intent, severely deteriorated concrete foundations must be refurbished or replaced. Failure to complete repairs could result in a catastrophic failure, causing outages or personal injury. Hydro has carried out engineering inspections of all 230 kV stations and identified foundations requiring repairs. Additionally, Hydro performs visual inspections of foundations every 120 days during regular terminal station inspections. Foundations identified for repair are addressed under this program.

4.2.2 Fire Protection

Hydro's terminal station control buildings contain combustible materials. As these facilities are unattended, a fire could spread, causing severe damage to protection and control wiring and equipment which would cause extended and widespread outages. To restore of a terminal station severely damaged by fire to normal operation could take months.

Hydro is installing fire suppression systems in its 230 kV terminal stations to protect the control cabinets and cables and any other critical equipment from being destroyed by a fire, without damaging sensitive electronic equipment and wiring.

In the 2015 and 2016 CBAs Install Fire Protection projects, Hydro received approval to install fire protection in the Holyrood and Bay d'Espoir terminal stations respectively. Due to their criticality, Hydro intends to continue its program to install fire suppression systems in all 230 kV terminal stations.

4.2.3 Control Buildings

Terminal station control buildings contain critical station infrastructure such as protection, control, and monitoring equipment, telecontrol equipment, station service equipment, and compressed air systems. Many control buildings also contain office, breakroom, and washroom facilities, for use by Hydro crews when working in the station. As the equipment in control buildings is critical to the function of the terminal station, it is imperative that Hydro ensures the structural integrity, weather-tightness, and security of its control buildings. While addressing these issues, Hydro also ensures that building auxiliaries, such as electrical, plumbing, and HVAC systems function properly, to ensure reliable and safe operation and use of the terminal station and the control building.

Typical refurbishment activities for control building involve replacement of the roof membrane (Figure 17), siding, and doors (Figure 18), and may also include replacement of electrical equipment (such as distribution panels, transfer switches, or low-voltage disconnects), plumbing (such as water service entries and internal plumbing), and HVAC (such as intake and exhaust fans, louvers, heaters, and air conditioning equipment).

In 2016, Hydro submitted its "Upgrade Office Facilities and Control Buildings Condition Assessment and Refurbishment Program Asset Management Strategy Plan" in its 2017 CBA, which outlined Hydro's approach to address aging and failing building infrastructure. Beginning with the 2019 CBA, Hydro will undertake the refurbishment of control buildings under the Project.

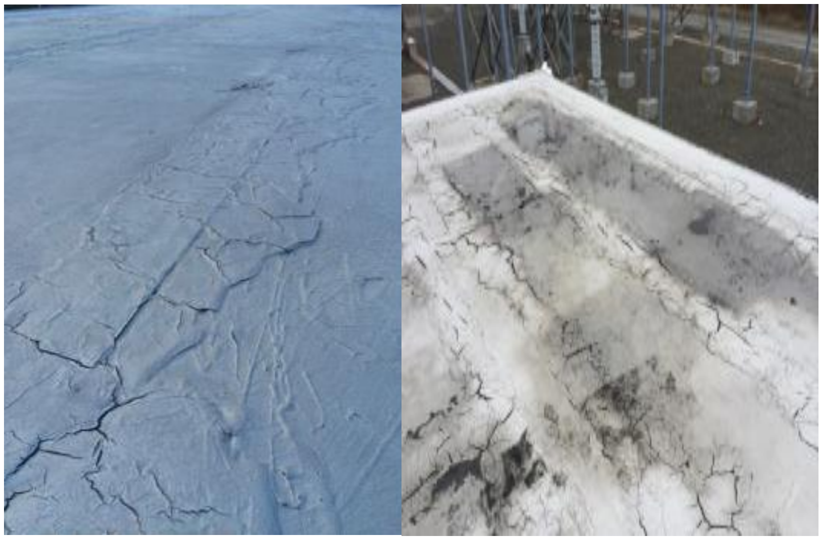

Figure 17: Terminal Station Control Buildings (Come by Chance and Sunnyside) Showing Cracking and Deterioration of the Roof Membrane System

Figure 18: Building Exterior Cladding and Exterior Doorways Displaying Severe Rusting and Deterioration

4.3 Protection, Control, and Monitoring

4.3.1 Protection and Control Upgrades and Refurbishment

The terminal station protection and control system automatically monitors, analyzes, and causes action by other equipment, such as breakers, to ensure the safe, reliable operation of the electrical system, or to initiate action when a command is issued by system operators. The protection and control system also provides indications of system conditions and alarms, and allows the recording of system conditions for analysis. Hydro carries out capital work on various protection and control equipment, including:

- Protective relays;
- Breaker failure protection;
- Tap changer controls;
- Data alarm systems;
- Frequency monitors;
- Digital fault recorders; and
- Cables and panels.

Electromechanical and Solid State Protective Relay Replacement

Protective relays monitor and analyze the operation conditions of the electrical system. When a relay identifies unacceptable operating conditions, such as a fault, it will initiate an action to isolate the source of the condition by commanding high-voltage equipment such as breakers to operate. Protective relays play a crucial role in maintaining system stability and preventing hazardous conditions from damaging electrical equipment or harming personnel.

Older relays existing on Hydro's system are the electromechanical and older solid state types, and lack features such as data storage and event recording capability. Modern digital multifunction relays are used to replace these older style relays, as they have increased setting flexibility, fault disturbance monitoring, communications capability and metering functionality, and offer greater dependability and security, enhancing system reliability. Digital and electromechanical relays are showing in Figure 19.

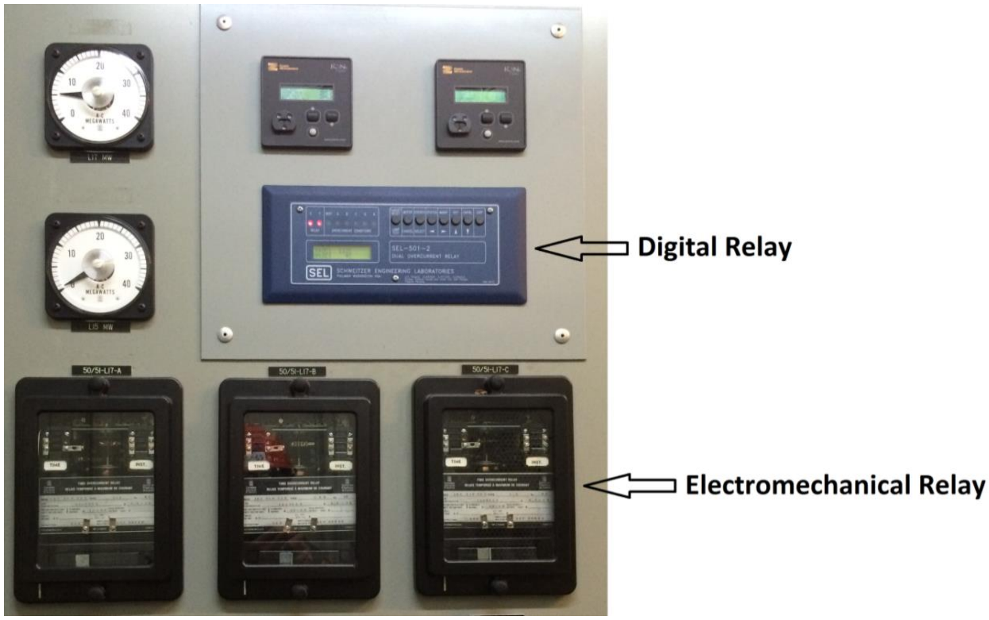

Figure 19: Digital and Electromechanical Relays

In the "Report to the Board of Commissioners of Public Utilities Related to Alarms, Event Recording Devices, and Digital Relays" dated August 1, 2014, Section 3.1 stated that "*Hydro plans to review its existing transformer, bus, and line protections in an effort to develop plans for future implementation of modern digital relays with data storage and fault recording capabilities.*" To fulfill this commitment, Hydro completed the following:

- A review of all transformer, bus, and line protection on 230 kV, 138 kV, and 69 kV systems, including data storage and fault recording capabilities; and
- A plan to replace all existing electromechanical transformer, bus, timer, and line protection relays with modern digital relays. The 230 kV relays are the priority for the first phase of the plan, with 138 kV and 69 kV to follow.

As part of the annual Terminal Station Refurbishment and Modernization project, Hydro will continue to execute the replacement of 230 kV electromechanical and obsolete solid-state transformer, line, and bus relays with modern digital multifunction relays, which began in 2016 under the Replace Protective Relays Program. Additionally, in line with Hydro's response to CA-NLH-037 as part of the 2016 CBA, Hydro installed redundant multifunction transformer protection relays in 2016 for transformers rated above 10 MVA. Under this program Hydro will continue to install these upgrades.

Breaker Failure Protection

Protective relaying is designed to trip a breaker during fault conditions to remove the fault from the electrical system so as to minimize equipment outages and maintain system stability and safe, reliable operation. When a breaker does not properly isolate a fault, other breakers will be commanded to trip to isolate the fault. This will result in larger outages but will ensure isolation of the original fault in a time to minimize damage to equipment and minimize impact to the system. The failure of a breaker to isolate a fault when commanded is called a Breaker Failure.

Prior to 2014, breaker failure protection was implemented only in Hydro's 230 kV terminal stations. In 2014, Hydro completed a review of breaker failure protection in 66 kV and 138 kV terminal stations. Hydro also developed a protection and control standard "Application of Breaker Failure Relaying", calling for breaker failure protection on transmission breakers rated at 66 kV and above. From this review, Hydro identified 20 terminal stations requiring breaker failure protection.

As part of Hydro's 2016 CBA, Hydro proposed and received Board approval for the installation of breaker failure protection in three terminal stations. As part of the annual Terminal Station Refurbishment and Modernization Project, Hydro will continue its plan to execute the installation of breaker failure protection in the remaining terminal stations. As well, Hydro has identified concerns with the reliability of legacy breaker failure in 230 kV stations and will be replacing as necessary under this program.

Tap Changer Paralleling Control Replacement

Tap changer paralleling controls are designed to:

1) Ensure the load bus voltage is regulated as prescribed by the setting;
2) Minimize the current that circulates between the transformers, as would be due to the tap changers operating on inappropriate tap positions;
3) Ensure the controller operates correctly in multiple transformer applications regardless of system configuration changes or station breaker operations and resultant station configuration changes.

Current tap changer controls are of similar vintage as the power transformers dating back to the late 1960's, and require replacement. Recent feedback from the tap changer paralleling control supplier indicated older equipment has capacitors that will dry out over time resulting in control issues.

Additionally, it was recommended the same controller model be applied to all transformers to optimize tap changing control. The control issues as described by the supplier have been seen by Hydro staff at numerous sites.

Hydro plans to start replacing tap changer paralleling controls in 2018 beginning at Western Avalon Terminal Station.

Equipment Alarm Upgrades

Alarms inform the Energy Control Centre ("ECC") and operating personnel that equipment and relaying requires attention, and are communicated to the ECC, and/or displayed locally on the station annunciator.

Figure 20: Annunciator Commonly Found in Hydro Terminal Stations

Hydro's review of Alarms, Event Recording Devices, and Digital Relays found that by providing more detailed alarm schemes, the ECC and local operators are able to troubleshoot system events more accurately and quickly.

Hydro's internal study identified required increases to alarm detail to the ECC for five 230 kV terminal stations. Stony Brook, Holyrood, Sunnyside, Oxen Pond, and Massey Drive were assessed. Hydro proposed and received approval to implement the proposed upgrades at the Stony Brook terminal station as part of the 2016 CBA "Upgrade Data Alarm Systems" project. Hydro will continue its plan to install improved data alarm management as part of the Terminal Station Refurbishment and Modernization project, with the remaining stations being addressed in future CBAs.

Frequency Monitoring Additions

As a result of investigations into the outage of January 2013, a recommendation was made to install frequency monitoring devices on the Island Interconnected System to allow better analysis of system events, such as pre and post-fault scenarios. It was recommended that one such device be installed in an Eastern, Western, and Central location on the Island Interconnected System. Hydro Place (East), Massey Drive Terminal Station (West), and Bay d'Espoir Terminal Station #2 (Central) have been chosen for the installation of frequency monitoring devices. This work was completed in 2018 and will be removed from this program.

Digital Fault Recorders

Digital Fault Recorders ("DFR") record analog electrical data, such as voltage, frequency, and current, as well as digital relay contact positions, at a high resolution to allow Hydro to determine the cause and location of an electrical fault. This data allows Hydro to restore service in a timely manner, address system configurations and settings to mitigate the impact of future faults, and improve the protection of critical electrical infrastructure. Hydro has DFRs deployed in several stations, and has a program to install DFRs in areas where Hydro does not have sufficient DFR coverage to allow the analysis of faults.

Protection and Control Cable and Panel Modifications

This program will cover protection and control panels and wiring that may require alteration, replacement, or addition to existing wiring due to deterioration from environment conditions, accidental damage or the modification/addition of protection and control equipment.