Q. Reference: Newfoundland Power's 2027 Capital Budget Application, 2.2 Substation Power Transformer Strategy, page 7, Footnote 20

a) In addition to the diagnostic maintenance inspections identified for Newfoundland Power's power transformer fleet, provide an outline of any additional physical inspection activities carried out. Detail how the results are used to assess the transformer's condition, remaining life, and replacement timing.

b) Provide the maintenance history for each transformer from 2016 to 2026 and explain how that history supports replacement rather than further maintenance or repair.

c) Identify all maintenance or repair actions considered before concluding that replacement is required.

A. GENERAL

Newfoundland Power completes major transformer overhauls on each of its substation power transformers approximately every 12 years. The frequency of power transformer maintenance activities is as follows:

(i) Full transformer maintenance for each transformer is scheduled every 12 years.[1] This frequency is subject to change depending on transformer oil analysis, physical condition and coordination with other ongoing projects.[2]

(ii) Transformer protection checks are completed every six years (if applicable).[3]

(iii) Transformer main tank and tap changer oil is tested annually. This includes dissolved gas analysis and furan analysis. For units above 50 years of age, transformer main tank oil is tested twice per year.[4]

(iv) Infrared scans are completed annually.[5]

(v) Visual inspections are completed approximately every six weeks during routine substation inspections.[6]

---

[1] Full transformer maintenance includes megger testing, power factor testing, capacitance testing, winding resistance testing, and transformer turns ratio testing. Transformer deficiencies are corrected during the maintenance.

[2] The 12-year full transformer maintenance interval could be lower or higher. The cycle depends on the condition reflected in the latest oil samples and other factors, such as whether there is an opportunity to coordinate with the deployment of a portable substation for capital work.

[3] Transformer protection checks are completed on gas detector relays and temperature gauges. Checks include a visual inspection of protection equipment, megger testing, voltage tests, alarm checking, cooling checks, and moisture prevention.

[4] Oil tests include standard oil tests and dissolved gas in oil analysis. Standard oil tests check for contaminants and moisture, which at unacceptable levels can lower the dielectric strength of oil and cause a fault. Dissolved gas analysis is used to monitor and diagnose internal transformer electrical problems, such as the presence of arcing or poor electrical connections.

[5] Infrared scans use a thermal imaging camera to check the temperature of equipment and its connections. If a problem is detected, corrective work will be completed, such as replacement of a terminal connection.

[6] Visual inspections on power transformers include checks for tank and cooler leaks, cooling fan and pump operation, operation of liquid and winding temperature equipment, oil level, tank pressure, breather operation and controls operation.

A 12-year overhaul cycle enables Newfoundland Power to plan and complete overhauls efficiently, without creating operational pressure on the system or critical assets, such as portable substations required for transformer offloading. Based on Newfoundland Power's operating experience, a 12-year overhaul interval has proven to be appropriate and effective. Refer to Attachment A for additional details on standard transformer maintenance practices.

In addition to routine maintenance activities, Newfoundland Power completes transformer repairs and life extension activities when necessary. These activities are not performed on a prescribed schedule and are evaluated on a case-by-case basis using inspection results, oil analysis, electrical testing, operating history, physical condition assessments and system requirements.

The scope of repair or life extension work considered for an individual transformer depends on the age of the transformer, the condition of critical components, the estimated service life extension that can reasonably be achieved, and economic justification relative to replacement. In some cases, targeted repairs or refurbishment can provide an appropriate life extension. In such cases, full replacement of the transformer would be deferred. In other cases, repairs may only address individual deficiencies while the underlying deterioration of critical components such as the transformer insulation system continues. Where the expected reliability improvement, life extension, or economic benefit of future repair activities is limited, replacement may be determined to be the recommended option.

Major transformer repairs may require the unit to be removed from service and shipped to a third-party facility outside of the province. Repair costs can be significant and often approach the cost of a replacement transformer without providing comparable service life, reliability, or warranty coverage. In addition, repaired transformers typically retain some of the original components, such as the transformer tank, which may continue to deteriorate over time and remain susceptible to corrosion.

Replacement decisions are not based on a single test result or inspection finding. Rather, replacement is typically considered when multiple indicators demonstrate that continued maintenance is no longer expected to provide an economic or reliable long-term solution. These indicators may include deteriorating oil analysis results, evidence of insulation degradation, recurring maintenance requirements, increasing levels of physical deterioration, elevated risk assessments, or situations where major repairs are no longer considered practical or cost-effective relative to replacement.

RESPONSE

a) Visual inspections on power transformers are completed approximately every six weeks during routine substation inspections. These inspections include checks for tank and cooler leaks, cooling fan and pump operation, operation of liquid winding temperature equipment, oil level, tank pressure, breaker operation, and controls operation.

For each transformer considered for replacement, the results of physical inspections, oil analysis, electrical testing, infrared inspections, maintenance history, and condition assessment tools are considered collectively to determine overall condition and necessary replacement timing. Typically, no single inspection or test result determines the replacement timing. Rather, replacement decisions reflect the cumulative condition of the transformer, the observed rate of deterioration, operational impacts, reliability risks, procurement lead times, and the practicality of continued maintenance or repair.

b) The maintenance history of each of LAU-T1, LBK-T1, HAR-T2, and RRD-T3 is included in the Substation Power Transformer Strategy.[7] The maintenance histories demonstrate that Newfoundland Power has continued to perform routine maintenance, repair activities, and major overhauls on these transformers throughout their service lives. The histories indicate that corrective actions have been taken where practical to address issues such as oil leaks, instrumentation failures, tap changer maintenance requirements, cooling system deficiencies, corrosion, and protection equipment concerns.

Condition assessments on these power transformers show that deterioration has continued despite these maintenance activities. Maintenance activities temporarily addressed individual deficiencies but did not stop the underlying aging and deterioration of critical transformer components such as insulation systems, tap changers, tanks, bushings, and cooling systems.

As a result, replacement of these four transformers, rather than continued maintenance or repair, is now deemed necessary. The replacement is therefore recommended in the *2027 Capital Budget Application*.

LAU-T1
Key considerations for the 50-year-old LAU-T1 include both recurring maintenance requirements and continued deterioration of critical components.

Tap changer maintenance was completed in 2004, 2010, 2017, and 2025. While these maintenance activities improved operating conditions, subsequent testing identified recurring deterioration of the tap changer system.

The transformer has also required repeated corrective work associated with physical deterioration. Painting was completed in 2010, 2017, and 2025. Conservator piping and various deteriorated components were replaced in 2017. In 2025, a steel box was installed to contain oil leakage from a deteriorated valve.

---

[7] See the *2027 Capital Budget Application*, report *2.2 Substation Power Transformer Strategy*, Appendix A, Attachment A; Appendix B, Attachment A; Appendix C, Attachment A; Appendix D, Attachment A.

The PTX assessment indicates that the Normal Degradation index of LAU-T1 is approaching the 0.60 threshold, which is highly correlated with transformers whose paper insulation is no longer capable of providing reliable service. Since insulation degradation cannot typically be addressed through standard maintenance activities, these indicators collectively indicate that continued maintenance is unlikely to provide a reliable long-term solution.

LBK-T1

Key considerations for the 64-year-old LBK-T1 relate primarily to widespread physical deterioration affecting multiple major transformer components.

Radiator repairs were completed in 2021, but the condition continued to deteriorate. The existing radiators exhibit advanced corrosion and require replacement. The radiators are non-standard in design, are welded directly to the transformer tank, and are not equipped with isolation valves, significantly increasing repair complexity.[8]

In addition to radiator deterioration, inspections identified corrosion on the main transformer tank, evidence of oil leakage at a bushing base, and deterioration of the sealing system. Repairing these deficiencies would require recoating and remediation work that would further reduce the remaining wall thickness of the tank and increase future leak risk. Inspections also identified mechanical damage to high voltage and low voltage bushings, including chipped porcelain sheds that reduce creepage distance and compromise insulation performance.

Collectively, these conditions indicate widespread deterioration affecting multiple major transformer components. Addressing these issues would require refurbishment or replacement of radiators, bushings, coatings, seals, and associated equipment on a 64-year-old transformer. Given the age of the unit and extent of deterioration, replacement was recommended over repair.

HAR-T1

Key considerations for the 57-year-old HAR-T1 relate primarily to insulation deterioration and abnormal internal conditions.

The PTX assessment indicates the Normal Degradation Index of HAR-T1 exceeds the 0.60 threshold, which is highly correlated with transformers whose paper insulation is no longer capable of providing reliable service.

Oil analysis also produced a Code 2 assessment score, indicating abnormal internal heating. Standard maintenance activities are generally unable to reverse paper insulation degradation or reliably address deterioration within the transformer insulation system.

8 See the *2027 Capital Budget Application*, report *2.2 Substation Power Transformer Strategy,* Appendix B, page B-3.

Combined, the PTX results and oil analysis findings indicate continued deterioration of critical internal components and support replacement rather than continued maintenance.

RRD-T3

Key considerations for the 51-year-old RRD-T3 include recurring physical deterioration and continued insulation aging.

Corrosion-related issues have been addressed through maintenance activities. The transformer was painted in 1992 and again in 2020. Leak repairs were completed in 1997, 2011, and 2015. Conservator and gas detector piping, gauges, and related components were replaced in 2020.

While these maintenance activities successfully addressed individual deficiencies, they did not prevent continued deterioration of the transformer insulation system. The PTX assessment indicates that the Normal Degradation Index of RRD-T3 is approaching the 0.60 threshold. This degradation is primarily associated with aging of the paper insulation system, in which mechanical strength declines as a function of time and temperature. Standard maintenance activities are generally unable to reverse paper insulation degradation or reliably address deterioration within the transformer insulation system. Replacement is deemed necessary and, as such, it is recommended in the *2027 Capital Budget Application*.

c) Prior to concluding that replacement was required, Newfoundland Power considered the following maintenance and repair activities where appropriate:

- Routine visual inspections
- Annual oil analysis and diagnostic testing
- Infrared inspections
- Major transformer maintenance and overhauls
- Tap changer maintenance and refurbishment
- Internal inspections
- Instrumentation replacement
- Cooling system repairs
- Leak repairs
- Corrosion mitigation activities

The maintenance histories document the maintenance and repair activities completed on each transformer. Once the determination was made that continued maintenance or refurbishment is not expected to provide an acceptable long-term reliability outcome, practical life extension, or economic justification, replacement of the transformer was deemed necessary. The replacement is therefore recommended as part of the *2027 Capital Budget Application*.

ATTACHMENT A:

Transformer Maintenance Practices

Maintenance Standard Number: MSP009
Effective Date: 2002-04-15
Superseding Date: 1982-09-10

POWER TRANSFORMERS

Created by: M. Rideout
Revised by: M. Greening
Reviewed by: M. Greening
Approved by: G. Samms

The following steps are considered as standard procedures for maintenance on power transformers. Other scope may be completed as required on a case-by-case basis.

Form MSF009, *"Power Transformer Maintenance Report"*, is used in reporting Maintenance I, III, IV or V through paper form or PowerDB. Also, Maintenance Standard Form MSF001, *"Nameplate and Description"*, is completed during Maintenance I.

Type of Maintenance				Procedure
I	III	IV	V	
X				1. Assign and install an ID number.
X				2. Record the complete nameplate information on MSF001. This will include the main nameplate, the tapchanger (if it has a separate nameplate), bushings, lightning arresters, gas detector relays, fan motors, and any other accessories that would have a nameplate.
X				3. An internal inspection should be made on all new transformers and on transformers that have been in storage or have been moved from one location to another. For transformers that have been energized previously, this internal inspection may be omitted if the Substation Asset Management Group has determined that it is not practical or necessary. Refer to MSR017 for detailed guidelines to be followed in completing this internal inspection.
X				4. Perform a dew point test if moisture is suspected to have entered the tank.
X				5. Ensure continuity of all CT taps; check that the CT is not grounded; and check all ratios. Refer to MST005 for ratio checking procedures.
X				6. If not already installed, install a fall arrest bracket on the unit.
X	X	X		7. Ensure an appropriate PCB label is installed on the unit. Record the PCB level on MSF009. Place a label on the inside of the control cabinet indicating PCB level. If no lab oil test has been previously conducted on the unit, take an oil sample for lab testing.
X	X	X		8. Make a visual inspection, noting the general condition of the transformer. Check for such things as dents, oil leaks (particularly around gasketed joints), paint condition, damaged bushings, broken glass on gauges, abnormal readings on thermometers, oil level gauges, etc. Report issues to the electrical Maintenance Planner Group.
X	X	X	X	9. Ensure that the tank is properly grounded. A good, permanent, low-resistance ground is essential. All grounding and neutral connections to be upgraded to 19/#9 copper clad steel unless otherwise noted.
X	X	X		10. Check the oil level as indicated by the gauge on the conservator tank or on the main tank if there is no conservator tank. Top up as required.
X	X	X		11. Check bushings for oil leakage and oil level where possible. Report issues to the electrical Maintenance Planner Group

NEWFOUNDLAND POWER
A FORTIS COMPANY

POWER TRANSFORMERS

Type of Maintenance				Procedure
I	III	IV	V	
X	X	X		12. Check radiators for paint condition, oil leaks, and position of all valves. Ensure Radiators are well painted to prevent corrosion and rusting unless otherwise noted.
X	X	X		13. Check the condition of the silica gel. Replace as required. Breather piping and silica gel canister shall be replaced unless otherwise noted. Refer to MSR020 for silica gel breather requirements.
X		X*		14. Install or replace humidity absorbent packets in the gas detector relay as required if relay is not replaced.
X	X	X	X	15. If the unit is equipped with a spill pan, check that heat tracing and valve is operational. Ensure pan is free of oil and drained.
X		X*		16. Clean bushings and lightning arresters where they exist. The porcelain should be kept clean and free from atmospheric pollution. Inspect closely for chips and cracks. All chips and cracks are to be reported to the Electrical Maintenance Planner Group and painted with glyptol to prevent moisture ingress. In cases with excessive damage bushings may require replacement
X	X	X		17. Painting is done at intervals determined by visual inspection. Refer to MSR014 for painting guidelines. The entire transformer shall be painted unless otherwise noted.
X	X	X		18. Check that the upper diaphragm on the explosion vent is intact. PRD and piping shall be installed if identified in the scope of work by the Planner.
X		X		19. Check the operation of the gas detector relay. Refer to MST007.
	X			20. Record the reading of the maximum indicating pointer on the temperature gauges and check that the method of resetting the pointer is operational.
X		X		21. Check the operation of the temperature gauges including the settings of switches. Refer to MST010.
X	X	X		22. Check the cooling fans for proper operation. Ensure that drain plugs or adhesive tape is removed from fan motors. If the unit is equipped with a fan exerciser, ensure it is operational and that an appropriate time interval is established.
X	X	X		23. Check the dielectric value of the insulating oil. Refer to MSR013 for method of testing. Refer to MSR010 for oil dielectric requirements.
X	X	X	X	24. Obtain an oil sample with a syringe and bottle for gas analyses. Refer to MSR013 for sampling procedures. Record results on MSF020. Do this during Maintenance V if requested.
X		X*		25. Megger the windings. To do so, all bushings should be wiped clean and dry and all connections to live bus bars and lightning arresters should be disconnected. Give the measured resistance on MSF009 (do not make the temperature correction conversion). Refer to MSR012 for evaluation of megger readings and maximum meggering voltages. Refer to MST008 for transformer meggering procedure.

POWER TRANSFORMERS

Type of Maintenance				Procedure
I	III	IV	V	
X		X*		26. Megger core ground with a 500V megger. If this will require removing oil, which may not be practical, this step may be omitted. This must be done as part of the acceptance procedure for a new unit.
X		X*		27. Carry out ratio tests with ratiometer. Refer to MST011 for TTR procedure.
		X		28. Carry out power factor and winding resistance testing. See appropriate manufacture manual for the test equipment that is being used.
X		X		29. Carry out a Transformer Protection Devices Inspection as per maintenance standard MST017. Ensure to inspect all junction boxes, making special note of any wear/cracking or any point at which water could enter the box. Ensure all gaskets and seals are checked and replaced as necessary. Install humidisorb packs in all junction boxes.
X		X		30. Ensure that all accessories are tested. Examine all apparatus, electrical cables, conductors, signaling and operating devices. A megger test is recommended if applicable.
X	X	X		31. Observe drop leads for signs of strain on bushings or associated equipment. If transformer is de-energized, check line connections for tightness.
X	X	X		32. Ensure that the control cabinet is clean and dry. Ensure the cabinet heater is operating to prevent condensation build up.
X				33. If present, ensure that any bushing wrap is removed.
X*		X		34. If transformer is to be kept as spare, wrap bushings with plastic wrap.
			X	35. For unplanned maintenance as a result of breakdown or diagnostic tests, make the necessary repairs and note on MSF009.
X	X	X	X	36. Any changes made or abnormal conditions found should be noted on MSF009 and reported to the Substation Asset Management Group.
X	X	X	X	37. Send copies of form MSF009 to the Electrical Maintenance Planners' group along with any unresolved issues with the equipment or with the procedures. Any outstanding work shall be entered into an Avantis work request and submitted.
X	X	X	X	38. Update maintenance history and nameplate information in Avantis.

*** Only if the transformer is de-energized and if it is deemed necessary to make these checks.**

Caution: For some transformer maintenance, control wiring may have to be disconnected to disable alarms and trip circuits. This normally applies to gas detector relays, temperature gauges, pressure relief devices, etc., that are connected to external trip schemes. An approved protection plan may be required for such cases.

Note: For transformers with an on-load tapchanger, refer to MSP012 for standard maintenance procedures.