Q. Please identify what Hydro considers to be the complete project description and justification filed with the Board for the replacement of the Come By Chance T1 and T2 High Voltage Bushings (H1, H2, H3), and please identify by what process Hydro considers these capital expenditures to have been approved by the Board, including the applicable reference thereto in an order of the Board. Please include with your response copies of all filings referred to in the response.

A. The complete project description and justification for the 2015 Upgrade Power Transformers project was submitted to the Board for approval as part of Hydro's 2015 Capital Budget Application. Specifically, the project description is found in the report titled *"Upgrade Power Transformers"* in Volume 2 of that application; see IC-NLH-171, Attachment 1.

As stated IC-NLH-171, Attachment 1, page 12 of 64:

> *Hydro must also address leaking bushings as well as those that are suspected to have PCB levels not compliant with the PCB Regulations, 2008*[2]*. The latest regulations state that all equipment remaining in service beyond 2025 must have a PCB concentration of less than 50 mg/kg and equipment remaining in service beyond 2014, when the extension permit expires, must have a PCB concentration of less than 500 mg/kg. Hydro has an estimated 800 sealed bushings that were manufactured prior to 1985 which are suspected to contain PCBs greater than 50 mg/kg and possibly greater than 500 mg/kg. The PCB levels are unknown because sampling and testing the oil destroys the bushing. Projecting these numbers over 15 years will require 54 bushings changed per year. As bushings come out of service further testing will be*

performed to help determine if manufacturers used non PCB oil (< 2ppm). It is anticipated the number required to be removed will be less than 800. $790,000 has been budgeted for 2015, $1,206,000 for 2016 and $922,000 in each subsequent year to continue bushing replacements.

[2] PCBRegulations SOR/2008-273

The Come By Chance T1 and T2 High Voltage Bushings (H1, H2, and H3) were highly likely to be PCB contaminated bushings, due to age, type, and supplier, and thus were required to be replaced under the new 2008 Government regulations regarding PCB contamination along with many other bushings of a similar situation within Hydro’s system.

Hydro subsequently received approval for the above project in Order No. P.U. 50(2014), in IC-NLH-171, Attachment 2, the Board stated:

Hydro’s proposed multi-year construction and purchase of improvements or additions to its property in excess of $50,000 to begin in 2015, as set out in Schedule B to this Order, are approved.

Please refer to Hydro’s response to IC-NLH-172 for Hydro’s commitment to improve communications in current and future capital projects that are to be, or are intended to be, specifically assigned to customers.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador DAVID W. HICKS SIGNATURE July 29/2014 DATE NEWFOUNDLAND & LABRADOR	Electrical DWH
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Upgrade Power Transformers

July 2014

newfoundland labrador hydro
a nalcor energy company

SUMMARY

This proposal is for the upgrading of power transformers which includes refurbishment or replacement as appropriate based upon the results of a number of condition assessment techniques. Hydro has developed a methodology to determine which transformers are to be refurbished or replaced. This methodology is aligned with procedures of other North American utilities with similar transformer assets.

One part of the methodology uses an oil quality testing method with the data used as an input to a ranking tool. This ranking tool developed by Hydro determines a priority ranking score. The lowest ranked transformer will be flagged as the next priority unit to have oil reclamation completed. The oil reclamation process is a process used to extend the service life of aging transformers. Additionally oil analysis, which includes dissolved gas analysis, is completed on transformers and their components to determine if a refurbishment or replacement is required.

The second part of the methodology uses Furan Oil Analysis which yields data on the brittleness of the cellulose insulating paper inside the transformer. This level of brittleness known as the Degree of Polymerization (DP) expresses an oil testing result as a whole number which can range from 200 to 1,000. If the DP level is less than 200 the paper is considered very brittle and is an indication that the transformer is at end of its service life. Hydro is using a DP number of 400 as the baseline target for end of life with transformers. This baseline will give a suitable lead time to procure a replacement transformer.

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1 INTRODUCTION

This project is required to either extend the life of existing power transformers or to replace units meeting the replacement criteria outlined in Section 2 of this report. This project does not address the purchase of new transformers due to load growth. Many transformers have been in service for more than 30 years (see Section 3.1).

Hydro has 54 terminal stations in the Island Interconnected System and three in the Labrador Interconnected System. The terminal stations contain a total of 111 power transformers rated 66 kV and above. Table 1 provides the number of transformers for each transformer rating.

Table 1: Transformer Distribution by Rating

Transformer Rating (kV)	Number of Transformers
230/138	15
230/69	4
230/66	14
230/46	1
230/16	3
230/13.8	17
230/6.9	0
138/69	2
138/66	6
138/25	8
138/13.8	2
138/12.5	0
69/25	9
69/13.8	1
69/12.5	1
69/7.2	1
69/4.16	6
69/0.6	1
66/25	9
66/13.8	2
66/12.5	1
66/6.9	5
66/4.16	1
66/0.6	2

Power transformers are a critical component of the power system. At generating stations transformers are referred to as step up transformers. These transformers step up the voltage for power transmission from the generation source voltage to the line voltage. A higher transmission voltage yields a lower transmission current and much smaller transmission line losses. Reducing the transmission current allows the transmission line to be a smaller size and weight. Lower current also reduces the amount of power loss during transmission. At a terminal station or a substation, step down power transformers are used to convert the voltage down to a distribution voltage level suitable for delivery to end users. Figure 1 shows a picture of a 75 MVA, 230/66 kV power transformer at Hardwoods Terminal Station.

Figure 1: Power Transformer T4 at Hardwoods Terminal Station

The basic components of a power transformer are:

- Transformer tank – The tank is the largest visual component of the transformer, it is constructed of steel and is used as a containment assembly for all the internal components of the transformer including:

- Core – this is the foundation of the transformer, it provides the location for the installed windings which are the turns arrangement for the transformer. Cores are generally constructed of a laminated magnetic material implementing many different construction designs;
- Windings – this is the wrapping of electrically conductive material, typically copper or aluminum around the transformer core. Each winding or turn is electrically insulated from each other. Each transformer typically contains two windings, one for its high voltage connection and one for its low voltage connection, although it is not uncommon for some transformers to contain one or three windings;
- Clamping assembly – This is the mechanical components required to keep the windings and core stable and rigid. The clamping components are stressed when the transformer is under heavy electrical loading or during fault conditions; and
- Insulation system – The two components of the insulation system include the insulating oil and the combination of cellulose paper and pressboard. The transformer oil acts to insulate the windings from ground potential and provides a medium for cooling the transformer. The cellulose paper and pressboard are used to insulate each turn of the winding.

- Bushing – this cylindrical external component, usually constructed of porcelain or composite material, is mechanically connected to the top of the transformer tank and the overhead electrical conductors. The bushing provides an electrical interface between the internal winding conductors and the external electrical conductors. Typically, all power transformers have six bushings; three bushings for high voltage and three for low voltage while providing an electrical interface between the internal winding conductors and the external electrical conductors.
- Radiators – this is a cooling device used on some transformers, some radiators include fans. Radiators are always external and mechanically mounted to the

transformer.

- Load Tap Changers – an external electrical device that allows small adjustments to the transformer's voltage level to provide voltage regulation. The load tap changer typically includes two types: the de-energized tap changer and the on-load tap changer.

This project addresses the refurbishment or replacement of the existing transformers that are in the latter period of their lifecycle. When a transformer ages it typically involves the degradation of its insulation system. This aging process reduces both the mechanical and dielectric strength of the transformer and in turn, its reliability. For comparison, if the same electrical fault was placed on both an aged transformer and a new transformer, the impact of these electrical forces would create a situation where the probability of survival of the older transformer is reduced, in relation to the newer unit. A second effect that creates aging is the level of power loading on a transformer in its lifecycle. Higher loading negatively impacts the transformer as when load is increased the operating temperature will also increase which affects the cellulose paper's ability to insulate over time. This continued weakening of the winding insulation can reach a point where it can no longer sustain the mechanical stresses and results in a failure of the transformer.

2 PROJECT DESCRIPTION

Hydro, like many North American utilities, has been working to maximize the life of its in-service power transformer units. In recent years, there has been significant effort by Hydro to deal with power transformer risks resulting from their age and/or condition. Areas of concern include:

1. Quality of the transformer oil;
2. Condition of the radiators;
3. Condition of the on load tap changers;
4. Leaking transformer bushings and PCB contaminated bushings;
5. Failure of the protective devices including gas relays, winding temperature devices and oil level equipment; and
6. Leaking transformer gaskets.

This project applies a strategic approach to address all transformer issues collectively as opposed to individual projects. This will utilize known information from the six problem areas stated above to execute a transformer upgrade or a complete replacement. Another factor for this project is the latest Environment Canada Polychlorinated Biphenyls "PCB Regulations SOR/2008-273" which requires that all equipment have PCB concentration levels of less than 500 mg/kg by the end of 2014 (with an extension which Hydro received in 2010) and all equipment have PCB concentration levels of less than 50 mg/kg by the end of 2025. A concern for power transformers relating to PCBs are the sealed bushings.

A transformer replacement will be based on the following criteria:

- DP of cellulose insulation paper less than 400[1]. Using a transformer oil sample, specialized laboratories can perform a furan analysis of the oil. As the cellulose paper insulation ages, furanic compounds are released into the oil. Based on the level of furanic compound, a DP number is determined. New transformers have a DP number of more than 1000, while transformers near the end of their service life

[1] Hydro has chosen 400 as the target to allow adequate time to plan a replacement before the threshold of 200 is met.

show DP numbers of 200 or less.

- Combustible gas concentration in the transformer oil indicates an internal fault is developing. The gas generation rate is regularly recorded by performing a Dissolved Gas Analysis (DGA) from an oil sample.

The current DP value for Bay d'Espoir (BDE) transformer T7 is 491. This number has decreased annually and is approaching the criterion for replacement. Because of its deteriorating insulation system, an 18 – 24 month time frame to engineer, purchase and install a power transformer and importance of Bay d'Epsoir transformer T7 to the system, the planned replacement of the transformer T7 has not changed. The schedule remains to replace the transformer in 2016 with engineering and procurement beginning in 2015.

The current DP value for Cat Arm (CAT) transformer T1 is 395. This number is decreasing annually and is now below the criterion for replacement. Hence, the planned replacement of the Cat Arm transformer T1 has progressed. The scheduled replacement of the transformer is 2016 with engineering and procurement beginning in 2015.

It is generally more cost effective and reliable to replace power transformers in a planned process rather than as a reaction to a failure. Hydro will replace transformers within a three to five year window once the DP number becomes less than 400. This will provide the necessary lead time to purchase and schedule the installation during the most appropriate system outage window. Currently, the delivery time for power transformers is estimated to be between 18 and 24 months after receipt of order.

3 JUSTIFICATION

Presently, 67% of Hydro's power transformers are greater than 30 years of age. Prior to 2009, Hydro had been addressing the six concern areas as stated in Section 2 on an individual project basis. This methodology required significant investment of effort and cost so Hydro decided that an overall transformer upgrading program should be created. The upgrading project would allow an orderly and efficient upgrade of the power transformer fleet.

Hydro's condition assessment tool (which evaluates oil quality parameters such as acidity, interfacial tension, power factor, and criticality) provides a ranking of all transformer units. This ranking determines which transformers Hydro will schedule for oil reclamation. The 2014 rankings will determine the reclamation work for 2015 and this data is shown in Appendix A. The units planned for completion in 2015 are Bay d'Espoir (BDE) T5 (replace the oil) and Bay d'Espoir T6 (reclaim the oil). Bay d'Espoir T5's oil will be replaced since it has a PCB concentration that is above 2 ppm. The two units planned for completion in 2016 are Upper Salmon (USL) T1 and Buchans (BUC) T1. To continue with this work, a $341,704 allocation is budgeted for 2015, $262,000 for 2016 and $200,000 annually thereafter for power transformer oil reclamation in order to meet the target of two transformers annually.

Ranking tools have been developed to rank the condition of the transformer radiators and tap changers. Corrosion of transformer radiators has resulted in coolant leaks. As shown in Appendix B, the planned radiators for replacement in 2015 are on Bay d'Espoir T10, Bay d'Espoir T5 and Hardwoods T3. To continue with the radiator replacement portion of this project, a budget estimate of $326,000 has been identified for this work in 2015, $226,000 for 2016 and $173,000 in each of the subsequent years in order to meet the target of two transformer radiators replacements annually.

For tap changers, a review of the maintenance philosophy was completed in 2006 and it was determined that the optimal approach was to perform condition based monitoring using tap changer oil samples. This oil sample approach is more objective as the oil samples are analyzed by a certified lab. The results are used with the ranking tool to provide a priority ranking based on the oil quality and its particle counts. The ranking in Appendix C shows that there are transformers ranked as low as condition 3 that will still require work in the near future. The plan for tap changers is to upgrade one tap changer in each year until all units showing condition 3 or higher are completed. $103,000 has been budgeted in 2015, $98,000 for 2016 and $75,000 in each of the subsequent years to complete this work. The Stony Brook Transformer T1 tap changer has been scheduled for an overhaul in 2015.

Hydro must also address leaking bushings as well as those that are suspected to have PCB levels not compliant with the PCB Regulations, 2008[2]. The latest regulations state that all equipment remaining in service beyond 2025 must have a PCB concentration of less than 50 mg/kg and equipment remaining in service beyond 2014, when the extension permit expires, must have a PCB concentration of less than 500 mg/kg. Hydro has an estimated 800 sealed bushings that were manufactured prior to 1985 which are suspected to contain PCBs greater than 50 mg/kg and possibly greater than 500 mg/kg. The PCB levels are unknown because sampling and testing the oil destroys the bushing. Projecting these numbers over 15 years will require 54 bushings changed per year. As bushings come out of service further testing will be performed to help determine if manufacturers used non PCB oil (< 2ppm). It is anticipated the number required to be removed will be less than 800. $790,000 has been budgeted for 2015, $1,206,000 for 2016 and $922,000 in each subsequent year to continue bushing replacements.

There are also critical protective devices and wiring that are reaching end of life and beginning to show signs of failure in recent years. As shown in Table 6 of Section 3.1.5, the annual cost for this work has ranged from $11,000 to $42,300 and it is not expected to decline. As a result, $60,000 has been budgeted in 2015, $31,000 for 2016 and $24,000 in each subsequent year to address these issues. The protective devices being replaced in

[2] PCB Regulations *SOR/2008-273*

2015 will be determined based on condition assessment performed in 2015.

3.1 Age of Equipment or System

Of Hydro's transformer fleet, 67% are greater than 30 years of age and 30 units are 45 years old or older. Figure 2 shows the age distribution for Hydro's transformers rated 66 kV and greater.

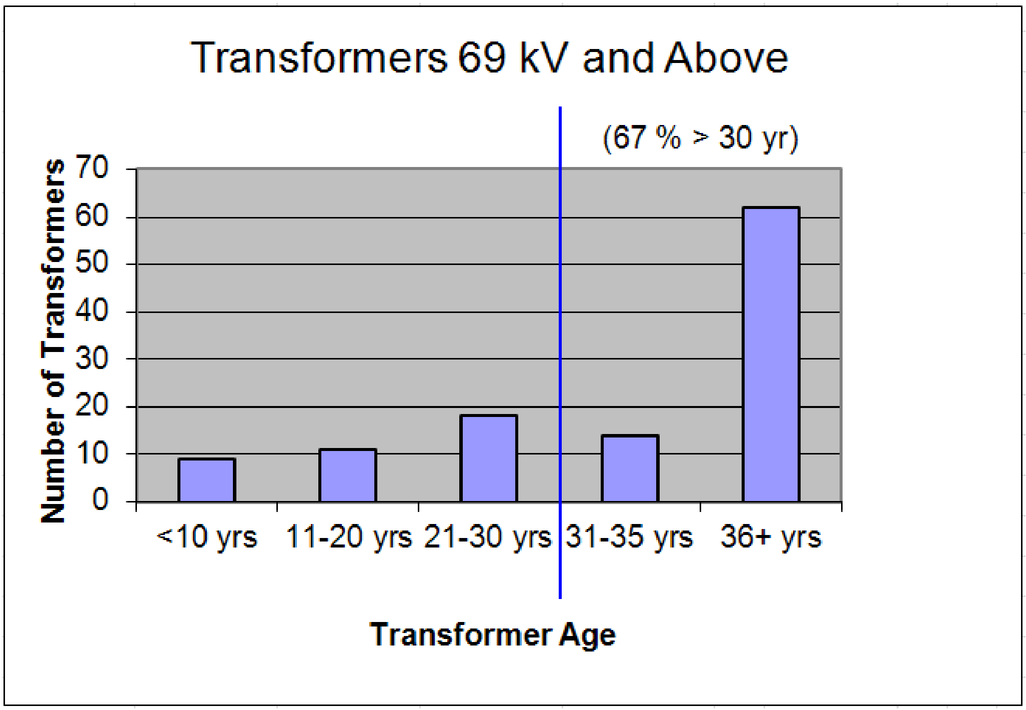

Figure 2: Transformer Age Distribution (66 kV and above)

3.2 Major Work and/or Upgrades

There were no major capital upgrades to the power transformer fleet before this capital program began. Prior to 2009, work was confined to regular maintenance and inspections with minor operational type repairs as discussed below. Since 2009, major capital upgrades to the power transformer fleet have been performed as identified in Tables 2 through 7.

3.2.1 Quality of Oil

As a transformer ages, sludge builds up on the windings inside the power transformer tank. This is a result of the chemical reaction between oxygen, oil, and moisture. As the chemical process takes place, oxygen inhibiter is depleted and the acidity of the oil begins to rise.

This chemical action results in the color of the oil darkening and a reduction in the electrical insulating properties of the oil. If this process continued without intervention, the acid would attack the cellulose insulating paper causing it to become brittle. If the insulating paper becomes too brittle, the probability of failure due to a breakdown of the mechanical strength of the paper is higher. Transformers in this condition have a low DP number.

Oil quality data has previously shown the acidity on several units to be outside the accepted guideline as stated by Institute of Electrical and Electronic Engineers (IEEE) Standard 637-1985[3]. Hydro decided the most cost effective way to rejuvenate this oil was to reclaim the power transformer oil. This reclaiming process brings aged oil back to within oil quality parameters similar to new oil. Figure 3 shows how transformer oil has a visual change in oil color as it is reclaimed from start to finish. Table 2 outlines the work completed in this area to date. In 2005 an in-house transformer ranking tool was developed (see Appendix A) to prioritize units for reclamation based upon oil quality values and criticality within the Island Interconnected System. As per the guideline for PCB Regulations, all transformer oil that is 2mg/kg and greater will be reclaimed on site, with the reclamation unit located next to the transformer.

Figure 3: Reclaimed Oil – Start to Finish (left to right)

[3] 637-1985 - IEEE Guide For the Reclamation of Insulating Oil and Criteria for Its Use

Table 2: Oil Reclamation Work Completed (Five Year Period)

Year	Major Work and/or Upgrade	Comments
2013	Scheduled work on T1 at Bay d' Espoir and T1 at Upper Salmon.	Bay d'Espoir T1 was not completed due to scheduling of the work around the outage. Upper Salmon T1 was replaced with Happy Valley T1 Spare due to a cost savings opportunity that arose whereby the work would be cost shared with Lower Churchill Project.
2012	Scheduled work on T4 at Bay d'Espoir	Hot oil cleaning, flushed transformer and replaced oil with reclaimed oil, $63,000
2011	Scheduled work on T5 at Bay d' Espoir.	Work not completed due to outage cancellation.
2010	Reclaimed transformer T2 at Hinds Lake	Completed work with in-house staff using Hydro's Fluidex Reclamation unit at a cost of $82,000
2009	Reclaimed transformer T1 at Cat Arm and T1 at Hinds Lake	Completed work with in-house staff using Hydro's Fluidex Reclamation unit at a cost of $107,000 for Cat Arm T1 and $83,000 for Hinds Lake T1

3.2.2 Work Completed on Radiators

Historically, radiators were manufactured from painted carbon steel. Newfoundland and Labrador's environmental conditions have resulted in high corrosion levels causing damage beyond repair. In some cases corrosion damage resulted in oil leaks. Figure 4 shows radiators that were replaced at Bottom Waters Terminal Station. A list of the completed transformer radiators replacements in recent years is shown in Table 3.

Figure 4: Radiators being replaced at Bottom Waters Terminal Station

Table 3: Transformer Radiator Replacements (Five Year Period)

Year	Major Work and/or Upgrade	Comments
2013	Scheduled Work on Hardwoods T2 not completed.	Radiators were ordered but due to delivery times, not installed.
2012	Replaced all 5 radiators on T3 at Hawke's Bay	Replacement Cost: $34,000
2012	Replaced all 3 radiators on T6 at Holyrood	Replacement Cost: $66,000
2012	Replaced all 4 radiators on T8 at Holyrood	Replacement Cost: $62,000
2011	Scheduled Work on Holyrood T8 not completed.	Work not completed due to resource requirements on other capital work.
2010	Replaced seven of eight radiators on Bay d'Espoir T11	Old radiators replaced with new. Replacement of one radiator postponed to future year due to broken radiator valve Cost: $128,000
2010	Replaced twelve radiators on Stephenville T1	14 old radiators replaced with 12 new Cost: $182,000
2009	Replaced all eight radiators on Holyrood SST-12	Leaking radiators were removed and replaced with new Cost: $53,000

3.2.3 Work Completed with on Load Tap Changers

In 2006, Hydro implemented a new maintenance process for on load tap changers which involves oil sampling to determine tap changer condition. On load tap changers are required to change the position of the winding inside the transformer to maintain acceptable customer voltages. This involves moving components which wear over time. To measure this wear an oil sample is taken to analyze the oil quality and particle count. This is a non-intrusive method that can determine the condition of the internal parts of the tap changer. Table 4 lists work completed on transformer tap changers in recent years.

Table 4: Transformer Tap Changer Overhauls (Five Year Period)

Year	Major Work and/or Upgrade	Comments
2013	Overhauled Massey Drive T3 Tap Changer	Cleaned diverter switch, replaced worn parts, replaced oil. Cost: $32,000
2012	Overhauled Western Avalon T5 tap changer	Cleaned diverter switch, replaced worn parts, replaced oil. Cost: $20,000
2011	Overhauled Stony Brook T1 tap changer	Diverter switch cleaned and oil replaced with new. Cost: $51,000
2010	Overhauled Hardwoods T1 tap changer	All 12 arcing contacts on diverter switch were worn and were replaced. Oil replaced with new. Cost: $82,000
2010	Overhauled Bottom Brook T1 tap changer	All 3 diverter switches (1 per phase) were replaced with rebuilt units. Oil replaced with new. Cost: $55,000
2009	Overhauled Oxen Pond T2 tap changer	Diverter switch cleaned and worn parts replaced; Damaged raise/lower contactor replaced. Oil replaced with new Cost: $56,000

Figures 5 and 6 below show the on load tap changer prior to and after refurbishment. The next steps for Hydro are to follow the recommendations that are outlined in the Table C-1 of Appendix C.

Figure 5: Before Overhaul

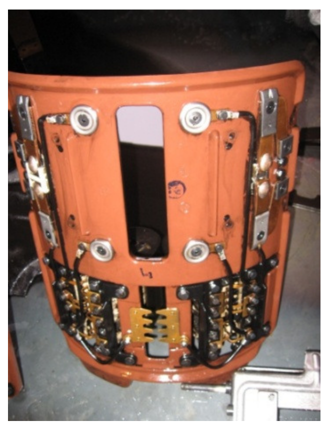

Figure 6: After Overhaul

3.2.4 Bushing Replacements

In recent years, bushings have been replaced due to leaks and poor Doble readings (high voltage insulation test). In the future, Hydro will also have to replace units to ensure that all bushings containing PCBs 50 mg/kg and greater are removed from service by 2025. Table 5 is a listing of transformer bushing replacements in recent years. The variation in bushing replacement costs is related to voltage class and current rating.

Table 5: Transformer Bushing Replacements (Five Year Period)

Year	Major Work and/or Upgrade	Comments
2013	Replaced one 4.16 kV bushings on Churchill Falls T31 Spare	Replaced bushings due to PCB-contaminated oil present in bushings Cost: $39,000
2013	Replaced three 230 kV bushings and three 13.8kV bushings on Bay d'Espoir T1	Replaced bushings due to PCB-contaminated oil present in bushings Cost: $81,000
2013	Replaced three 230 kV bushings on Western Avalon T1	Replaced bushings due to PCB-contaminated oil present in bushings Cost: $176,000
2013	Replaced three 230 kV bushings on Bay d'Espoir T6	Replaced bushings due to PCB-contaminated oil present in bushings Cost: $73,000
2012	Replaced three 230 kV bushings on Bay d'Espoir T4	Replaced bushings due to PCB-contaminated oil present in bushings Cost: $170,000
2012	Replaced three 230 kV bushings and three 138kV bushings on Bottom Brook T1	Replaced bushings due to PCB-contaminated oil present in bushings Cost: $230,000
2012	Replaced three 230 kV bushings and three 69kV bushings on Massey Drive T2	Replaced bushings due to PCB-contaminated oil present in bushings Cost: $205,000
2012	Replaced three 15 kV bushings on Bay d'Espoir T2	Replaced bushings due to leaking oil Cost: $38,000
2012	Replaced one 69kV bushing on St. Anthony Airport SST-1	Replaced bushing due to poor condition Cost: $7,000
2011	Replaced three 230 kV bushings on Oxen Pond T1	Replaced bushings due to PCB-contaminated oil present in bushings Cost: $29,000/bushing
2011	Replaced three 230 kV bushings on Bay d'Espoir T5	Replaced bushings due to PCB-contaminated oil present in bushings Cost: $30,000/bushing
2010	Replaced three 15 kV high current bushings on Bay d'Espoir T5	Replaced bushings due to PCB-contaminated oil present in bushings Cost: $18,000/bushing
2010	Replaced three 69 kV bushings on Western Avalon T1	Replaced bushings due to PCB-contaminated oil present in bushings Cost: $9,100/bushing
2009	Replaced three 15 kV high current bushings on Bay d'Espoir T6	Replaced three bushings due to leaks. These bushings were purchased in 2008. Cost: $7,200/bushing
2009	Replaced three 15 kV high current bushings on Bay d'Espoir T3	Replaced three bushings due to leaks. Cost: $16,000/bushing
Note: The cost for bushings outlined above prior to 2010 is from units taken from inventory. Units purchased at today's prices will be significantly higher.		

3.2.5 Protective Device Replacements

As a result of maintenance checks and alarms, both of which are indicating problems with the equipment, there is a requirement to replace transformer protection devices such as gas relays, winding temperature relays, oil temperature relays, and oil level devices. Table 6 is a listing of protective device replacements that have been completed in recent years.

Table 6: Protective Device Replacements (Five Year Period)

Year	Major Work and/or Upgrade	Cost
2013	Replaced three gas relays and two winding temperature relays	$20,000
2012	Replaced three gas relays, six winding temperature relays, and two fault pressure relays	$42,300
2011	Replaced five gas relays, one winding temperature relay, and one oil level relay	$29,000
2010	Replaced one winding temperature relay, one fault pressure relay, and one gas relay	$19,300
2009	Replaced three winding/oil temperature relays and one oil level relay	$11,000

3.2.6 Transformer Leaks

Oil leaks have been experienced on many transformers. These leaks are due to several failure modes including:

- Leaking bushings and bushing gaskets;
- Leaking valves;
- Leaking winding and oil temperature relays;
- Leaking gas relays;
- Leaking explosion relief devices;
- Leaking manhole and access covers;
- Leaking radiator gaskets and O-rings; and
- Leaking main tank top cover gaskets.

The majority of transformer oil leaks are the result of failed gaskets. Transformer gaskets are used to seal attached components to the transformer main tank. Hydro has noted that the gasket material is failing randomly throughout the transformer fleet and in some cases there are multiple occurrences on the same units. Refurbishments can be made to a transformer and the next inspection may reveal a leak on the same transformer in another location. The failure rate is accelerated by the age of the transformer and the thermal cycling experienced by the unit.

Depending on the location of the leak the cost of refurbishment and required outage time can be extensive. Extended outages to these power transformers jeopardize the integrity of the power system and compromise the quality of service to customers. To refurbish a leaking transformer, oil must be removed from the main tank to a level below the leak. This involves pumping and storing oil, installing nitrogen gas supply to protect the exposed internal components, and then filtering the oil on refill. If oil has to be removed to a level below the core and windings, it is required that a vacuum be put on the unit for 24 to 48 hours prior to filling. When oil is moved inside a transformer, a minimum dwell time of 24 hours is required to allow the oil to stabilize and release any trapped air prior to energizing. Each time a transformer is exposed to the atmosphere there is an increased risk of moisture contamination which could result in shortened life or premature failure of the transformer.

In 2015, $197,642 has been budgeted for leak refurbishment, $133,000 for 2016 and $102,000 in each of the subsequent years to complete this work. The leak refurbishment work includes the identification of leaking gaskets; this information determines a priority for gasket replacement on a transformer. When performing this work, all the transformer gaskets are replaced at this time with the exception of the top cover gasket. This methodology is considered a more cost effective method as the removal of oil is the major cost item on each transformer.

Currently, the highest areas of concern for transformer leaks (based on a combination of leak severity and transformer criticality) are those on the Bay d'Espoir (BDE) Generating Station Unit Transformers T1 to T6. In 2012, leak refurbishment plans were developed for BDE T1, T2, T3, T5, and T6 based on the assessments completed in 2011. Leak repairs are planned on BDE T5 and T6 in 2015 (see Appendix D for the BDE T5 and T6 Leak Repair Plan). With the leak repair plan beginning in 2012, Table 7 shows this completed leak repair.

Table 7: Leak Repairs Completed

Year	Major Work and/or Upgrade	Cost
2013	Scheduled BDE T1 – Not Completed	$19,000
2013	CAT T1 & T2 leak assessment & leak repair plan	$19,000
2012	BDE T4 - Replaced selected gaskets and performed leak tests. No leaks indicated.	$159,000

3.3 Operating Experience

3.3.1 Reliability Performance

3.3.1.1 Outage Statistics

Table 8 shows the latest statistics for the five-year average on the performance of power transformers for Hydro and the Canadian Electricity Association (CEA). A comparison is made between Hydro's five-year performance and the latest five-year average (2008-2012) of other utilities in Canada using CEA's statistical data. Hydro has had 14 forced outages in the past five years (2008-2012) but none were due to internal transformer failures.

Table 8: Power Transformer Performance

	Number of Forced Outages	Frequency (per a) [1]	Unavailability (percent) [2]
NLH (2008-2012)			
230 kV	14	0.056	0.0084
138 kV	7	0.088	0.0223
66 kV	1	0.010	0.0003
CEA (2008-2012)			
230 kV	869	0.171	0.6274
138 kV	1767	0.216	0.8231
66 kV	577	0.071	0.3686

[1] Frequency (per a) is the number of failures per year
[2] Unavailability is the% of time per year the unit is unavailable

In January 2014, Newfoundland Hydro experienced its first in-service catastrophic failure of a power transformer. The investigation into the incident determined the Sunnyside T1 transformer was most likely destroyed due to a low voltage bushing failure. Based on the findings of the report, several recommendations have been made, when implemented, would reduce the likelihood of another failure.

With an aging fleet of transformers, the risk of failure is high. Risk is evaluated by considering the probability of failure in light of the consequence of the event. It is important to note that an outage resulting from a failure of a power transformer would have a severe impact on the power system. This can be confirmed based on the events of January 2014.

3.3.2 Legislative or Regulatory Requirements

Section 16 of the latest Federal PCB Regulations state that the end-of-use date for equipment containing PCBs that are 500 mg/kg or greater was December 31, 2009. If this date could not be met owners were given an opportunity to apply for an extension up to 2014. Hydro made application in 2010 and received the extension to 2014. The regulations also state that equipment with PCB concentrations from 50 mg/kg to 499 mg/kg have to be out of service by 2025. In addition, Section 5(2) of the PCB Regulations prohibits a release of 1 gram of PCBs from in-use equipment.

Hydro, through CEA, is lobbying Environment Canada to have a regulatory amendment for sealed equipment such as instrument transformers and bushings to allow their use until 2025. Hydro's current budget is based upon receiving a regulatory amendment to 2025.

3.3.3 Safety Performance

This is a reliability based project. If this project is not completed there is a higher risk of transformer failure and the potential for extended power outages within the province which could negatively impact public safety.

3.3.4 Environmental Performance

One of the main potential sources of oil leaks is power transformers. Transformers contain Voltesso 35 oil which acts as an electrical insulation medium as well as a coolant. As transformers go through thermal cycling, oil leaks are discovered due to component or gasket system failure. Some leaks are significant, such as those discovered on the unit transformers at Bay d'Espoir, thus future investment is required to fix and replace transformer gaskets. A release of only one gram of PCBs from the in-use equipment is reportable to the federal government under the PCB Regulations, 2008[4] and the oil in the majority of the transformers is PCB contaminated.

Prior to 1980 many manufacturers of power transformer bushings used PCBs in insulating oil. The concentration levels of PCBs vary by manufacturer and also vary within manufacturer by year. This is important when reviewing the PCB Regulations, 2008 as issued by Environment Canada. The regulation gives users such as utilities the right to apply for extensions. Hydro applied for and received an extension from 2009 to 2014. Hydro, like other Canadian Electricity Association (CEA) members has a significant amount of sealed equipment with unknown levels of PCB. As a result Hydro has started and completed three years of the documented replacement plan. All CEA members, including Hydro, are actively pursuing a regulatory amendment to allow use of bushings and instrument transformers until 2025.

3.3.5 Industry Experience

Many utilities in North America are in a similar position as Hydro in that they have aging infrastructure and are seeking the most economic and reliable solution to this problem as it requires significant investment. There are many documented papers from various transformer owners on the subject of aging transformer infrastructure and various methods to deal with this issue. The majority have considered using condition assessment tools, either internally or through an outside vendor, to help with the decision to either upgrade or replace power transformers.

3.3.6 Vendor Recommendations

There are vendors such as ATI Weidman and Asea Brown Boveri (ABB) who are marketing condition assessment techniques for power transformers to provide customers with a list of weak units that are recommended for refurbishment or replacement. As presented in this report, Hydro has been tracking the problem areas and has developed in-house ranking tools to help determine where the investment should be directed.

[4] PCB Regulations *SOR/2008-273*

3.3.7 Maintenance or Support Arrangements

Routine maintenance as well as specialized power transformer work is completed using internal resources. Routine maintenance includes a visual inspection every three months for problems such as leaks, gauges not operating correctly, and other deficiencies. Every year oil samples are taken for oil quality and Dissolved Gas Analysis testing which provide input into the condition assessment tool. This condition assessment tool considers the criticality of the unit and provides an overall Transformer Priority Score (TPS) which is then ranked from highest to lowest. The transformer with the highest score is the unit that will be considered for oil reclamation during the next year. The priority listing for transformers is shown in Appendix A.

Transformers with on load tap changers have oil samples taken every three years to perform a Tap Changer Activity Signature Analysis (TASA) to help determine the condition of the tap changer. This is a special service offered by an oil analysis laboratory (TJH2b) which enables Hydro to develop a ranking of the condition for each of the on load tap changers. Any future work for tap changers will require a support arrangement from the manufacturer.

In 2005, a furan analysis was completed on all power transformers 66 kV and above with re-sampling planned every four years to help trend the aging process. The latest data set was completed in 2010. More frequent sampling will be performed based upon lab results.

On a six-year cycle, the transformer is taken out of service and subjected to electrical testing with protective devices verified, fan controls checked, windings insulation tested (Doble), and winding resistance verified.

3.3.8 Maintenance History

The recent maintenance history for power transformers is shown in Table 9.

Table 9: Annual Maintenance Costs for Power Transformers

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2013	120	113.3	233.3
2012	265	120	385
2011	143	142	285
2010	58	140	198
2009	34	53	87

3.3.9 Historical Information

This proposal is the seventh year of the power transformer upgrade program which started in 2009. The upgrades are planned and executed based on the condition assessments of the transformers. The appendices included in this report show which upgrades will be completed and in what year. The work completed in 2013 included a tap changer overhaul at Massey Drive T3, bushing replacements on Bay d'Espoir T6, Bay d'Espoir T1, Western Avalon T1 and Churchill Falls T31 Spare and protective device replacement on four transformers. The forecast costs for the work in each year of the project have changed from the 2012 submission. Table 10 provides a recent history of Upgrade Power Transformer projects.

Table 10: Budget Versus Actuals

Year	Capital Budget ($000)	Actual Expenditure ($000)
2014B	1,904.4	
2013	1,621.1	483.5
2012	1,246.3	1,496.4
2011	865.9	328.9
2010	815.5	912.7
2009	653.9	589.9

3.3.10 Anticipated Useful Life

The life of a power transformer is difficult to project as the variables for each transformer are unique. The location of the transformer, ambient temperature, number of electrical faults, and the level of power loading are some of the variables that affect each transformer. As each transformer is unique, the failure mode of a power transformer is typically random. However, the probability of failure will increase with age.

According to Electric Power Research Institute (EPRI), the average age of in-service power transformers is 37 years. In comparison, the Hartford Steam Boiler Institute states that the average life of a utility transformer today is 18 years. This is significantly lower than what has been documented by EPRI. IEEE[5] states a normal life expectancy at 20.55 years. The "bathtub" curve shown in Figure 7 is a typical curve provided to demonstrate where a particular device is in its lifecycle. Figure 7 is the typical% failure rate versus age curve for a power transformer. Based upon this curve, half of Hydro's in-service transformers are on the tip up part of the curve where the probability of failure begins to increase with time. Hydro is of the opinion that the older designed units have a longer life and if proper intervention is completed on the aged units, transformer life will be extended for an additional 10 to 15 years.

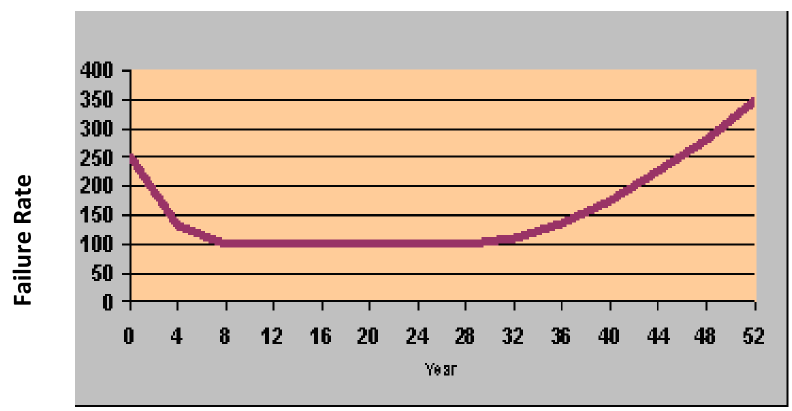

Figure 7: Power Transformer Failure Rate vs. Age

3.4 Development of Alternatives

There are two alternatives for existing transformers: refurbishment or replacement. Each alternative has the same level of operation and maintenance costs. The refurbishment option is preferred as it is least cost and once a unit is refurbished it should provide an operable transformer for the next ten to 15 years.

[5] IEEE Std. C57.91-1995 – IEEE Guide for Loading Oil Immersed Transformers, Section 8.1.2

4 CONCLUSION

The approach being proposed is to continually identify the transformers which are most at risk of failure and replace or refurbish critical assets on the system before they fail while in service. This approach over multiple years will direct capital investment towards the highest risk units.

As a result of the completed condition assessments to date, two transformers are targeted for replacement. Bay d'Espoir transformer T7 and Cat Arm transformer T1 are both scheduled for replacement in 2016.

For the remaining transformers, the upgrade option will be executed annually with a priority on individual work activities, but multiple activities will be completed if the work can be deemed safe and efficient. The priority of transformer units will be the transformer with the poorest ranking from the condition assessment of oil quality, radiator condition or tap changer oil condition results.

Table 11 summarizes the work plan for transformer upgrading planned for the next five years.

Table 11: Power Transformer Work Plan Summary 2015 to 2019 Estimated Costs

	2015 ($000)	2016 ($000)	2017 ($000)	2018 ($000)	2019 ($000)
Oil Replacement / Reclamation	342	262	200	200	200
Radiator Upgrades	326	226	173	173	173
Tap Changer Upgrades	103	98	75	75	75
Bushing Replacements	790	1,206	922	922	922
Protective Device Upgrades	60	31	24	24	24
GSU Leak Repair	198	133	102	102	102
Replace Power Transformers	2,621	5,046	0	0	0
Total	**4,440**	**7,002**	**1,496***	**1,496***	**1,496***

*This number does not include interest, escalation and contingency

4.1 Budget Estimate

Table 12: Project Budget Estimate

Project Cost:*($ x1,000)*	**2015**	**2016**	**Beyond**	**Total**
Material Supply	557.0	784.0	0.0	1,341.0
Labour	1,060.0	1,367.5	0.0	2,427.5
Consultant	14.4	35.8	0.0	50.2
Contract Work	1,676.9	2,927.8	0.0	4,604.7
Other Direct Costs	189.4	237.3	0.0	426.7
Interest and Escalation	243.3	579.5	0.0	822.8
Contingency	699.5	1,070.5	0.0	1,770.0
TOTAL	**4,440.4**	**7,002.3**	**0.0**	**11,442.7**

4.2 Project Schedule

The anticipated project schedule is shown in Table 13.

Table 13: Project Schedule for Each Year

Activity	**Milestone**
Initial Planning and Equipment Ordering Tendering (Transformer, Radiators, Bushings, and Protective Devices)	February 2015
Equipment Delivery	April 2015
Equipment Installations and Commissioning	June – November 2015
Project In Service	November 2015
Project Completion and Close Out	December 2015
Initial Planning and Equipment Ordering Tendering (Radiators, Bushings, and Protective Devices)	February 2016
Equipment Delivery (Radiators, Bushings and Protective Devices)	April 2016
Transformer Delivery (Ordered in February, 2015)	May 2016
Equipment Installations and Commissioning	June – November 2016
Transformer Installation and Commissioning	June – August 2016
Project In Service	November 2016
Project Completion and Close Out	December 2016

APPENDIX A

Transformer Priority Score and Ranking

		TRANSFORMER PRIORITY SCORE (TPS)									
		GSU (Vital)			Radial (CRITICAL)			All Other (IMPORTANT)			
Condition Factor		10	9	8	7	6	5	4	3	2	1
WORST	10	100	90	80	70	60	50	40	30	20	10
	9	90	81	72	63	54	45	36	27	18	9
	8	80	72	64	56	48	40	32	24	16	8
	7	70	63	56	49	42	35	28	21	14	7
	6	60	54	48	42	36	30	24	18	12	6
	5	50	45	40	35	30	25	20	15	10	5
	4	40	36	32	28	24	20	16	12	8	4
BEST	3	30	27	24	21	18	15	12	9	6	3
	2	20	18	16	14	12	10	8	6	4	2
	1	10	9	8	7	6	5	4	3	2	1

NOTES

- Prioritization is based equally on oil condition and transformer criticality and is also based on coordination with other work on the transformer

Table A-1 - Transformer Oil Priority Scoring

Transformer	**Transformer Priority Score (TPS)**	**Year (Reclaim/Replace)**
BDE T3	84.56	2014 (Replace)
HVY T1 Spare*	11.06	2014 (Replace)
OPD T1*	28.46	2014 (Replace)
BDE T5	80.85	2015 (Replace)
BDE T6	85.09	2015 (Reclaim)
BUC T1	56.71	2016 (Replace)
USL T1	91.08	2016 (Reclaim)
BDE T1	72.19	2017 (Replace)
DLS T1	56.41	2017 (Reclaim)
BDE T2	46.87	2018 (Replace)
GFC T2	44.47	2018 (Replace)

* oil is not being replaced due to condition but as a result of being removed for other work and not being able to be put back in due to its PCB contamination (PCB concentration >2ppm)

APPENDIX B

Transformer Radiator Replacement Plan

1) assumes 2 replacements annually (typically) with prioritization based on condition
2) planned year may be changed to co-ordinate with other work on that transformer

Station	Unit	Condition Rank (1 = Leak, 10 = New)	Comment(s)	Replacement Year
HRD	T7	3	1969, 3 radiators, significant rust, swelling and blistering, 1 of 3 radiators rated @7	2014
HWD	T2	3.5	1978, 12 radiators, original, have been painted, scaling and blistering	2014
WAV	T5	3.5	1989,4 radiators, rusted and swelling, 2 radiators drain pipes rusted severely	2014
BDE	T10	3.5	1976, 4 radiators original, all blistering and rusted	2015
HWD	T3	4	1968, 6 radiators, have been painted, scaling and blistering	2015
BDE	T5	4.5	1968, 18 radiators, some flaking and blistering	2015
BDE	T11	2.5	1970, original, significant swelling and blistering on 2, 2 @ 2-3, 7@5 2010: 7 (of 8) radiators replaced (Scheduled for 2016 due to unit availability)	2016 (1 only)
BDE	T3	4.5	1967, 20 radiators, some rust on surface, radiators appear to have been sand blasted and painted	2016
BDE	T2	4	1966, 20 radiators, evidence of rust and scaling, radiators have been sand blasted and painted	2017
CRV	T1	5	1976, 4 radiators original, painted, minor rust between fins, radiators welded on	2017
BUC	T1	5	1967, 17 radiators, original carbon steel. Painted, some rust and blistering	2018

Station	Unit	Condition Rank (1 = Leak, 10 = New)	Comment(s)	Replacement Year
GBK	T1	5	1987, 1 rad original painted, surface rust and some blistering	2018
HRD	T10	5	1990, 3 radiators, original, swelling and flaking	2018
DLS	T1	5.5	1989, 5 radiators original, significant surface rust, not severe, paint would extend life	2019
BBK	T3	6	1987, 3 radiators original, surface rust	2019

APPENDIX C

Transformer OLTC Overhaul: 5 Year Plan

Table C-1: Hydro Tap Changer Upgrade Policy

TASA Rank	Action
0	Resample 3 years after refurbishment (0 is not a TASA rank but indicates that the OLTC has not been sampled since refurbishment)
1 or 2	Resample 3 years after previous sample
3	Resample 6 months after previous sample and consider refurbishment
>3 (3*/4/4*)	Resample immediately to confirm, plan refurbish tap changer if reanalysis gives a TASA Rank of 3*, 4 or 4*

1) ranking is, in descending order of importance, done by TJH2b Rank, # of operations, years in service

2) assumes 1 OLTC overhauled annually based on ranking

Table C-2: Load Tap Changer Rankings

Location	Transformer	TJH2b Ranking	Planned Overhaul Year
St. Anthony Diesel	T1	3	2014
Stony Brook	T1	3	2015
Stony Brook	T2	2	2016
Western Avalon	T1	2	2017
Buchans	T1	2	2018
Bay d'Espoir	T10	2	2019

APPENDIX D

Bay d'Espoir Generator Step-up Transformer T5 & T6

Leak Repair Plan

GRID
SERVICE
North America Service

ALSTOM

Newfoundland Labrador Hydro

Recommendations for Repair of BDE Transformer T5

Serial Number: A-3S7757

Manufacturer/Year: Westinghouse/1968

Location: Bay D'Espoir Terminal, Newfoundland

Transformer Rating: 64/88.2 MVA – 230KV/13.8KV

Prepared By: Alessandro Noto

Checked By: Roger R. Hayes P.Eng.

Signed : Roger R Hayes P. Eng.

Date: January 4, 2013

GRID
SERVICE
North America Service

ALSTOM

SECTION INDEX

1.0 Scope

To provide documentation outlining detailed work methods as to how to modify/repair this transformer. The documentation shall contain the following:

- Detailed work instructions giving methods for stopping/repairing apparent oil leaks at gasketted accessories and parts.
- Specification of replacement components due to damage or expiration of usefulness.
- Detailed specifications for oil removal, oil handling/storage, processing and refilling, as well as vacuum application and pressure testing.
- Identification of badly contaminated areas and recommended procedures for cleaning and/or replacement of materials.
- Specifications for localized metal preparation due to rusting, and painting as needed.
- Provision of instructions for obtaining oil samples for quality analysis.
- Specifications for electrical testing of any components removed or replaced as part of these repairs.
- Provision of Bills of Material.
- Listing of any specialized tools and equipment.

2.0 Background Information

In September of 2010 Alstom Grid Canada (formerly Areva T&D Canada) were awarded a order number 17578 from Newfoundland Labrador Hydro for work as outlined in RFP 2010-45480. This order was essentially to perform a "leak assessment" on several transformers located at the Bay D'Espoir Terminal Station, for which this T5 transformer was included. The scope included a site visit and report with recommendations on the repair of identified leaks. This report was subsequently submitted on December 21, 2010 and the "Remedial Action Plan" from that report is the basis for the detailed repair recommendations contained here in.

3.0 Suggested Order of Repair Milestones

The following is a recommended sequential list of repair procedures to best facilitate the best efficiency and lowest cost for the repairs. Detailed instructions are supplied later in this report.

1. Perform a pressure test on the transformer as soon after it is de-energized, while the oil is still hot, to identify all leaks.
2. Obtain an oil sample.
3. Depending on the findings from the pressure test, proceed to repair any leaks as required.
4. Drain the oil from the transformer
5. Make repairs
6. Replace all damaged parts with new parts
7. Pressure Test transformer to assure quality work.
8. Apply vacuum to the transformer.
9. Refill with fully processed hot oil.
10. Take oil samples from the transformer for laboratory analysis.

11. Clean, prepare metal and repaint all rusted areas as required
12. Conduct Tests as appropriate on the transformer

4.0 Risk Assessment

Due to the uncertainty of the type of paint used on the transformer, a lead test on the paint to check for lead contamination is recommended. Before proceeding on any restorations on the transformer tank, keep in mind the appropriate environmental procedurals for that region. For worker safety the worker should wear a mask, goggles, gloves and properly fitting clothes to cover your skin. You should also lay a tarp on the ground under any area where you'll be scraping so paint doesn't work its way into the soil and dirt.

To maintain the integrity of the transformer during the repairs, a protective covering (See Bill of Material) will be placed over the exposed components of the inside the transformer. This protective covering will protect from the different types of weather and foreign objects from entering the transformer. To help against moisture during the repairs, a constant flow of dry air (See Bill of Material) will help protect from moisture contamination of the transformer.

5.0 Oil Leaks

As soon as the transformer is de-energized, apply dry air pressure of 3 psi. While pressurized, check all possible locations for leaks using talcum powder. Identify all leaks, empty the oil into a suitable storage container and proceed to repair.

Alstom recommends with the oil being emptied out of the transformer that all of the gaskets be replaced with appropriate material and size (see Bill of Material) given the age of the transformer.

Remove all plates and large valves to replace gaskets. Clean off all gasket and adhesive materials from both sides of the parts. Replace gaskets with appropriate material and size (see Bill of Material) and reassemble with new hardware.

Remove the side access plate. Clean and remove all the adhesive and gasket material. Clean all the rust and oil from the access plate and apply primer and top coat. Replace the gasket with the appropriate size and material (see Bill of Material) and reassemble with new hardware. (Refer to Original Assessment: Action 8)

Drain and remove all 13 radiators. Remove the existing drain valves and plugs and replace them with new fittings. Clean all rusted areas on the radiators and apply new primer and top coat (See Bill of Material). Remove the flanges and clean off existing adhesive and gasket material. Replace the gasket with appropriate material and size (See Bill of Material) and reassemble with new hardware. (See Diagram 1 and 2) (Refer to Original Assessment: Action 3 and 4)

6.0 Cover Gasket Replacement/Repair

Scenario One

Prepare cover to be removed by removing all plates, bushing and disconnect all external and internal connections using a tagging system. Clean off all gasket and adhesive materials from both sides of the parts. Measure gasket material and identify type of material used from previous gasket. Replace gaskets with appropriate material and size (See Bill of Material).

While bushings and external parts are removed off the cover, prepare cover for removal. Remove cover and existing gasket but be careful not to contaminate the inside of the transformer. Replace gasket with appropriate material and size (See Bill of Material) and reassemble the cover with new hardware. (See Diagram 1 and 2) (Refer to Original Assessment: Action 2)

Scenario Two

Prepare tank and cover to be welded together. Cover all bushings, conduit and other components with non flammable material. Remove any piping or conduit that will interfere with welding. Make sure the tank is grounded properly and that the tank is either filled with oil or has positive pressure of dry nitrogen before any welding is performed. Put in place the channel to be welded over top of the tank and cover seal. Have on hand proper fire extinguishers and one person on fire watch. Before any welding takes place, clean all areas to be welded of oil, paint and rust. Clean all surrounding area of any fire hazards and make sure to have a well ventilated area for the work to be performed. Then begin to make the weld repairs. (See Diagram 1 and 2) (Refer to Original Assessment: Action 2)

Note: for this procedure there is no need to remove any components on the cover which are not leaking oil.

7.0 Replacement of Damaged/Expired Components

Check functionality and quality of all valves and plugs. During initial pressure test, visually inspect for leaks. If the valves do not function or display a leak, after the oil has been removed and there is no pressure on the tank replace all damaged valves and plugs.

With the Low Voltage Bushing cover removed, clean away all debris and oil. Once clean, in large the drain holes for better drainage. Clean all rust away and apply new primer and top coat (See Bill of Material). The Low Voltage bushings were reported from the original site inspection as needed to be replaced. Newfoundland Hydro has reported that the Low Voltage bushings have been replaced and therefore is not an outstanding issue for this report. With the low voltage cover removed, inspect for leaks and/or damage on all low voltage bushings. Report all findings for a suggested action plan. (Refer to Original Assessment: Action 1)

Purchase a new radiator (Refer to Original Assessment: Action 5). Install with proper gasket size and material (see Bill of Material) and install with new hardware. Paint with new primer and top coat (See Bill of Material).

With the Low Voltage Bushing cover removed, clean away all debris and oil. Once clean, widen the drain holes for better drainage. Clean all rust away and apply new primer and top coat (See Bill of Material).

Remove temperature probes, clean and visually inspect for any damage (Refer to Original Assessment: Action 9). Recommend to test accuracy of gauge. Remove plate and gasket. Clean and replace gasket with appropriate gasket material and size (see Bill of Material). Replace gasket around probes with appropriate material and size and reinstall.

Inspect all conduits going to the current transformer terminal box and the current transformer terminal box itself (Refer to Original Assessment: Action 10, 11 and 12). Check for cracks, rusting and any damage. Replace all damaged conduit. During the pressure test check for leaks around the current transformer pucks and if leaks are present remove the pucks using a flagging system to identify all the wiring and change the gasket with the appropriate gasket material and size (see Bill of Material).

Silica Gel was reported from the original site inspection as expired. Newfoundland Hydro has reported that the silica gel has been changed and therefore is not an outstanding issue for this report.

8.0 Internal Tank Drying and Oil Related Procedures

After completion of work, apply 3 psi of dry air (see Bill of material) pressure to the transformer. Let stand for 24 hours to assure quality of work. After holding 3 psi for 24 hours conduct a Dew Point test. If the Dew Point test results are satisfactory (values are under the 1% dew point line shown in figure 1 attached) then begin vacuum filling.

If the Dew Point test results are unsatisfactory, then apply 1 Torr of vacuum for 18 hours or longer. Apply 3 psi pressure of dry air (see Bill of Material) to the transformer and hold pressure for 24 hours. Repeat Dew Point Test. If the Dew Point results are satisfactory then begin vacuum filling. If the results are unsatisfactory then repeat this step.

Once the Dew Point is satisfactory, begin vacuum filling. Prior to oil filling, take a sample of the oil to check for dielectric strength and moisture. The dielectric strength should be > 30 kV when tested to ASTM D877, and the water content < 25 ppm.

Connect the filler hose to the bottom of the transformer and the vacuum hose to the top. Apply 1 Torr of vacuum on the empty transformer and hold for the appropriate until stabilized. Once achieved begin hot oil filling (have oil between 40°C and 75°C) using heaters capable of achieving 75 degrees. Maintain at least 2 Torr of vacuum during filling. Allow time for the oil to cool down and top up as necessary. After filling allow a standby time of 36 hrs before energizing.

9.0 Oil Sampling and Analysis

After the transformer has been de-energized and prior to any work being started an oil sample must be taken. Refer to checklist (Standard Oil Test Form) for what tests need to be performed.

Prior to filling the transformer, the oil must be tested to assure no contamination has occurred. (Perform dielectric and moisture tests at site)

Prior to energizing the transformer an oil sample should be taken to assure quality of work and oil. (Also perform DGA test)

After a determined period of time that the transformer has been in service an oil sample should be taken to reassure the integrity of the transformer.

10.0 Cleaning of Badly Contaminated Areas

Clean all oil and debris off the tank and radiators. Remove all the rust and prepare the areas for primer and paint. On badly rusted areas use a portable sandblaster. (Use precautions for environmental laws in that region) Prior to applying primer make sure that all rust and oil have been removed. Apply primer and allow ample time to dry. After the primer is dry then apply the top coat.

11.0 Testing (Related to mechanical changes only)

After completion of work, conduct a winding resistance and polarity test on the transformer. Also conduct a polarity and ratio test on the Current Transformers. Polarity and Phase Relation tests are performed simultaneously in accordance with IEEE C57.12.90-2010 clause 6.3 to confirm Nameplate vector relationship.

12.0 Bills of Material

Item	Description	Quantity
Nitrile Gaskets	"O" Ring, Flat Gasket	To be supplied by Alstom
Galvanized Steel Rigid Conduit	straight pipe	
Liquid Tight Flexible Conduit	Final Connections used in place of 90° bends	
14 AWG Stranded Copper Wire	Type SIS, 600 V Rating with black insulation	
10 AWG Wire	Current Transformer Circuit Leads	
12 AWG Wire	Jumpers	
41 Strand Extra Flexible Wire	Used for any Wiring that is 12 AWG or larger	
Wire Connectors	Nylon Insulated Sleeve Ring-Tongue Compression	
Dry Air	Minimum -50°C Dew point	

Dry Nitrogen	100% Dry Nitrogen	Only necessary for welding
Safesol Solution	Cleaning Solvent	
Benjamin Moore KP1470	Primer	
Benjamin Moore KP2273	Top Coat	

13.0 Specialized Tooling and Equipment

Prior to all work be started, equipment and tools should be readily available to avoid stoppage of work.

- A Vacuum Pump => 150CFM capacity and capable of attaining a blank off pressure of 0.1 Torr or more (Oil Reclaimer provided by Newfoundland Hydro)
- A suitable vacuum gauge
- An Oil Processor with a suggested flow rate of 4500 Lph or higher and a heater system to heat the oil up to 75°C (Oil Reclaimer provided by Newfoundland Hydro)
- Minimum 1"Oil and 2" Vacuum hoses, suitable for mineral oil and the specified vacuum levels
- Storage container to hold 35 000 L of oil
- Man Lift capable of reaching the top of the bushings and a Crane with a lifting capability of 5000lbs
- Torque Wrench with the capability of 350 ft-lbs and Gasket Cutter
- Welder and arc welding equipment
- Protective covering for over the transformer while inside components exposed

14.0 General Mechanical

Torque specifications for bolted joints

Diameter (inches)	Torque (ft.-lbs.) Studs and Mild Steel Bolts	Torque (ft.-lbs.) Hi Strength Steel Bolts
0.375	17	--
0.500	35	55
0.625	70	105
0.750	120	190
1.000	175	450
1.250	350	780
1.500	600	1350

The High-Strength bolt head is identified by three lines spaced 120 degrees apart

Measure the tank temperature half way up the shaded side of the tank. Measure the tank pressure with a gauge that is calibrated in .1 lb graduations. These values are the initial pressure and temperature values, P1 and T1. After pressure is added, let the transformer set overnight and calculate the pressure change due to temperature. In order to determine the pressure change due to temperature, conversion to absolute pressure must be done. The formula for calculating the pressure change P2 due to temperature change T2 is: $P2 = P1 \times T2/T1$. Below is an example of how to use this formula.

- Example:
  - What will the pressure change in 10˚C drop in temperature? The transformer is left at 4:00 pm at a pressure of **5 psig** and a temperature of **22˚C**. At 8:00 am the next morning, a period of 16 hours, the tank temperature is 12˚C. What should the pressure be on the transformer?
  - P2 = P1 x T2/T1
    - where P1 is the initial absolute pressure, P2 is the final absolute pressure, T1 is the initial temperature (in Kelvin), and T2 is the final temperature (in Kelvin)
  - Calculation:
  - P1 = 14.7 psi + 5 psig = 19.7 psi
  - T1 = 295K (273K + 22˚C)
  - T2 = 285K (273K + 12˚C)
  - P2 = 19.7 psi + 275K/285K = 19.03 psi
  - P2 calculated = 19.02 psi – 14.7 psi = 4.3 psig
  - Therefor the relative pressure at 8:00 am is 4.3 psi

15.0 Timeline For Repairs

Pressure Test (Before Repairs)	24 hours	
Emptying Oil	8 – 12 hours	Depending on Oil Reclaimer
Cover Gasket (Scenario One)	16 – 40 hours	
Cover Gasket (Scenario Two)	8 – 24 hours	
Low Voltage Bushing gasket Replacement	8 – 16 hours	
Low Voltage Cover	2 – 6 hours	Depending on restoration
Temperature Probe	1 – 3 hours	Depending on restoration
Current Transformer Box and Components	8 – 40 hours	Depending on severity of leaks in the conduit, through wire and pucks
Radiators and Valves	24 – 40 hours	
Other Valves and Plugs	1 – 4 hours	Depending on findings from Pressure Test
Vacuum Filling/ Oil Processing	3 – 4 days	Depending on Dew Point test
Cleaning of Contaminated Areas	8 – 16 hours	Depending on condition of tank
Testing	4 – 8 hours	

16.0 Original Assessment

NALCOR INDVIDUAL TRANSFORMER WORK SCOPES

Transformer T5

1. Replace all (3) LV bushings with composite type similar to T6, and clean the inside of the box and open drain holes
2. Replace the cover gasket and bolts joining the tank cover and flange with new rust protected ones. Alternatively, weld a new steel channel over the existing joint and fasteners to completely seal the joint area
3. Drain and remove all the radiators, remove the drain valves and air release plugs, remove all rust from the area and replace with new fittings
4. Re-attach the radiators with new gaskets, and new fasteners
5. Add a new radiator, complete with new gaskets and fasteners were the one is missing on the north end
6. Empty the Silica Gel Breather and replace with new environmentally friendly Silica gel to the proper levels or alternatively add an appropriately sized Drycol Breather
7. Drain all oil from the transformer and reprocess before replacement
8. Remove the tank access plate, clean all the surrounding area of rust, supply a new gasket and reattach with new fasteners
9. Remove the temperature probe fitting, clean the area, and re-attach using a new gasket and associated fasteners
10. Remove the insulating plate that contains the CT terminals in the CT junction box. Clean the area, and reassemble with a new gasket and associated fasteners
11. Inspect any rigid conduit joining the CT junction box and the main control cabinet for signs of internal oil contamination, and replace if necessary
12. Remove all oil form the main control box and clean away all foreign debris
13. Clean the outside of the tank and radiators as thorough as practical and repaint all extremely rusted areas
14. Perform a 24 hour pressure test to confirm the integrity of the repaired bolted and gasketed joints
15. Conduct a CT ratio test at the control box terminals for those CT effected by the repair to ensure correctness and continuity of the connections
16. Take oil samples and conduct standard oil tests as well as DGA

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Standard Oil Sample Form

ALSTOM STANDARD and OPTIONAL TESTS for MINERAL OILS & SILICONE FLUIDS in NEW or SERVICE AGED TRANSFORMERS

Standard Test Package for all transformers:

- [x] Dielectric Strength to ASTM D1816 (2 mm gap) *
- [x] Dielectric strength to ASTM D877
- [x] Power Factor to ASTM D924 @ 25
- [x] Interfacial Tension to ASTM D971 *
- [x] Color to ASTM D1500 *
- [x] Neutralization Number to ASTM D974
- [x] Water Content to ASTM D1533
- [x] Visual Inspection to ASTM D1524 (oil) or D2129 (silicone)
- [x] Specific Gravity to ASTM D1298

Optional Tests:

- [ ] Dissolved Gas Analysis to ASTM D3612
- [ ] Corrosive Sulphur to ASTM D1275 *
- [ ] PCB Content to ASTM D4059
- [ ] Oxidation Inhibitor Content to ASTM D2668 *
- [ ] Oxidation Stability to ASTM D2440 & D2112 *
- [ ] Kinematic Viscosity @ - 40 C to ASTM D445
- [ ] Furan concentrations to ASTM D5837
- [ ] Particle Count to ASTM D6786
- [ ] Power Factor to ASTM D924 @ 100 C
- [ ] Fire & Flash Point to ASTM D92

Notes: a) Other tests available from the supplier at time of shipment.
b) Tests marked with * are not performed on Silicone Fluids

Form 202 January 5, 2011

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Figure 1

Job Number	
Tester	
Moister %	
Transformer Pressure psi	
Transformer Dewpoint ℃	
Transformer Ambient ℃	

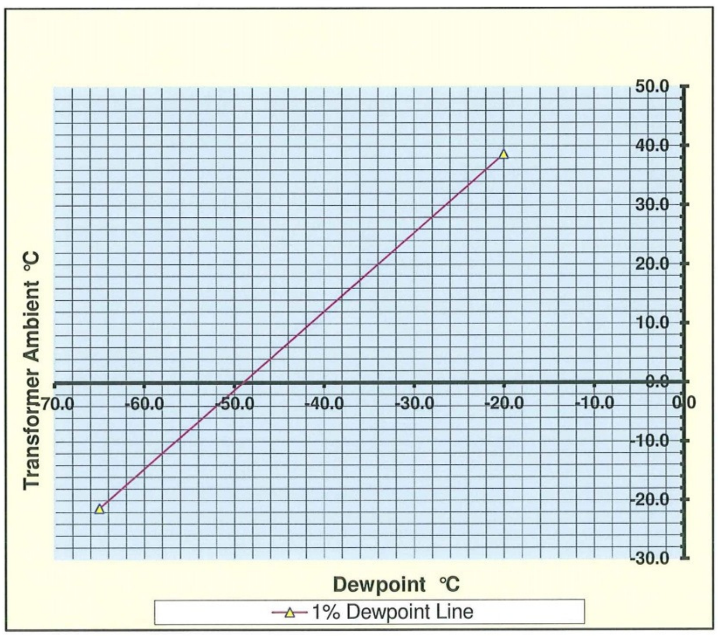

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Diagram 1
Low Voltage Side

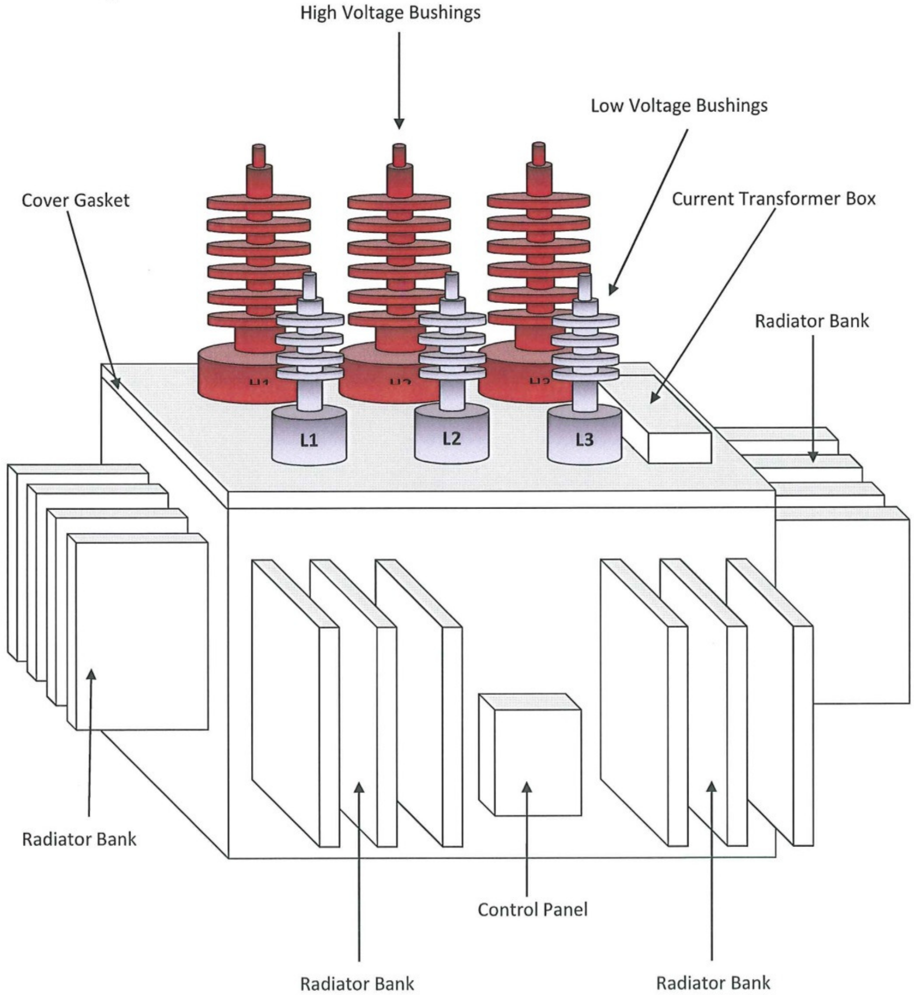

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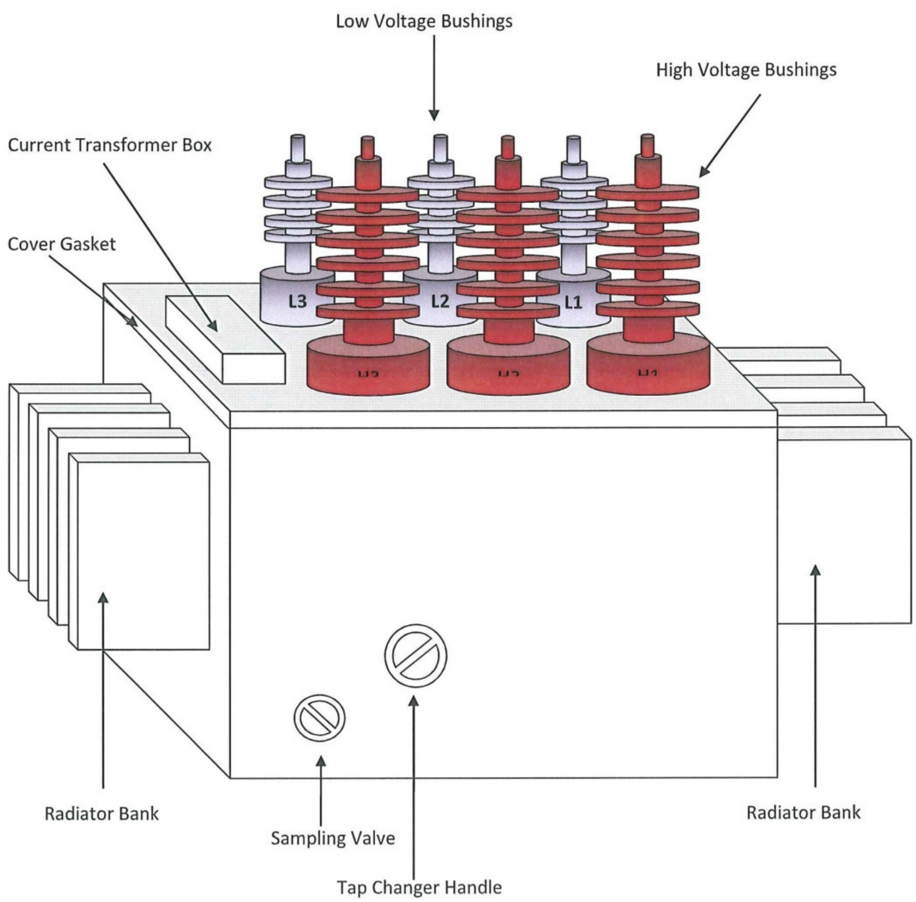
Diagram 2
High Voltage Side



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Newfoundland Labrador Hydro

Recommendations for Repair of BDE Transformer T6

Serial Number: A-3S7764

Manufacturer/Year: Westinghouse/1969

Location: Bay D'Espoir Terminal, Newfoundland

Transformer Rating: 64/88.2 MVA – 230KV/13.8KV

Prepared By: Alessandro Noto

Checked By: Roger R. Hayes P.Eng.

Signed : Roger R Hayes

Date: June 7, 2012

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SECTION INDEX

1.0 Scope

To provide documentation outlining detailed work methods as to how to modify/repair this transformer. The documentation shall contain the following:

- Detailed work instructions giving methods for stopping/repairing apparent oil leaks at gasketted accessories and parts.
- Specification of replacement components due to damage or expiration of usefulness.
- Detailed specifications for oil removal, oil handling/storage, processing and refilling, as well as vacuum application and pressure testing.
- Identification of badly contaminated areas and recommended procedures for cleaning and/or replacement of materials.
- Specifications for localized metal preparation due to rusting, and painting as needed.
- Provision of instructions for obtaining oil samples for quality analysis.
- Specifications for electrical testing of any components removed or replaced as part of these repairs.
- Provision of Bills of Material.
- Listing of any specialized tools and equipment.

2.0 Background Information

In September of 2010 Alstom Grid Canada (formerly Areva T&D Canada) were awarded an order number 17578 from Newfoundland Labrador Hydro for work as outlined in RFP 2010-45480. This order was essentially to perform a "leak assessment" on several transformers located at the Bay D'Espoir Terminal Station, for which this T6 transformer was included. The scope included a site visit and report with recommendations on the repair of identified leaks. This report was subsequently submitted on December 21, 2010 and the "Remedial Action Plan" from that report is the basis for the detailed repair recommendations contained here in.

3.0 Suggested Order of Repair Milestones

The following is a recommended sequential list of repair procedures to best facilitate the best efficiency and lowest cost for the repairs. Detailed instructions are supplied later in this report.

1. Perform a pressure test on the transformer as soon after it is de-energized, while the oil is still hot, to identify all leaks.
2. Obtain an oil sample.
3. Drain the oil from the transformer
4. Depending on the findings from the pressure test, proceed to repair any leaks as required.
5. Make repairs
6. Replace all damaged parts with new parts
7. Pressure Test transformer to assure quality work.
8. Apply vacuum to the transformer.
9. Refill with fully processed hot oil.

10. Take oil samples from the transformer for laboratory analysis.
11. Clean, prepare metal and repaint all rusted areas as required
12. Conduct Tests as appropriate on the transformer

4.0 Risk Assessment

Due to the uncertainty of the type of paint used on the transformer, a lead test on the paint to check for lead contamination is recommended. Before proceeding on any restorations on the transformer tank, keep in mind the appropriate environmental procedurals for that region. For worker safety the worker should wear a mask, goggles, gloves and properly fitting clothes to cover your skin. You should also lay a tarp on the ground under any area where you'll be scraping so paint doesn't work its way into the soil and dirt.

To maintain the integrity of the transformer during the repairs, a protective covering (See Bill of Material) will be placed over the exposed components of the inside the transformer. This protective covering will protect from the different types of weather and foreign objects from entering the transformer. To help against moisture during the repairs, a constant flow of dry air (See Bill of Material) will help protect from moisture contamination of the transformer.

5.0 Oil Leaks

As soon as the transformer is de-energized, apply dry air pressure of 3 psi. Hold the pressure for a 24 hour period. While pressurized, check all possible locations for leaks using talcum powder. Identify all leaks and proceed to repair.

Remove side access plates. Clean and remove all adhesive and gasket material. Clean all rust and oil from the access plates and apply primer and top coat (See Bill of Material). Replace gasket with appropriate material and size (See Bill of Material) and reassemble with new hardware.

Drain and remove all 14 radiators. Remove the existing drain valves and plugs and replace them with new fittings. Clean all rusted areas on the radiators and apply new primer and top coat (See Bill of Material). Remove the flanges and clean off existing adhesive and gasket material. Replace the gasket with appropriate material and size (See Bill of Material) and reassemble with new hardware. (See Diagram 1 and 2) (Refer to Original Assessment: Action 2 and 3)

6.0 Cover Gasket Replacement/Repair

Scenario One

Prepare cover to be removed by removing all plates, bushing and disconnect all external and internal connections using a tagging system. Clean off all gasket and adhesive materials from both sides of the parts. Measure gasket material and identify type of material used from previous gasket. Replace gaskets with appropriate material and size (See Bill of Material).

While bushings and external parts are removed off the cover, prepare cover for removal. Remove cover and existing gasket but be careful not to contaminate the inside of the transformer. Replace gasket with appropriate material and size (See Bill of Material) and reassemble the cover with new hardware. (See Diagram 1 and 2) (Refer to Original Assessment: Action 1)

Scenario Two

Prepare tank and cover to be welded together. Cover all bushings, conduit and other components with non flammable material. Remove any piping or conduit that will interfere with welding. Make sure the tank is grounded properly and that the tank is either filled with oil or has positive pressure of dry nitrogen before any welding is performed. Put in place the channel to be welded over top of the tank and cover seal. Have on hand proper fire extinguishers and one person on fire watch. Before any welding takes place, clean all areas to be welded of oil, paint and rust. Clean all surrounding area of any fire hazards and make sure to have a well ventilated area for the work to be performed. Then begin to make the weld repairs. (See Diagram 1 and 2) (Refer to Original Assessment: Action 1)

Note: for this procedure there is no need to remove any components on the cover which are not leaking oil.

7.0 Replacement of Damaged/Expired Components

Check functionality and quality of all valves and plugs. During initial pressure test, visually inspect for leaks. If the valves do not function or display leaks, after the oil has been removed and there is no pressure on the tank replace all damaged valves and plugs.

Inspect all wiring to and from the control panel. Remove, tag and replace all wiring that is deteriorated or damaged. (See Diagram 1)

Silica Gel was reported from the original site inspection as expired. Newfoundland Hydro has reported that the silica gel has been changed and therefore is not an outstanding issue for this report.

8.0 Internal Tank Drying and Oil Related Procedures

After completion of work and the transformer is air tight, apply 3 psi of dry air (see Bill of material) pressure to the transformer. Let stand for 24 hours to assure quality of work. If at any point during the 24 hour period the pressure drops below 3 psi then check for leaks. After holding 3 psi for 24 hours conduct a Dew Point test. If the Dew Point test results are satisfactory (values are under the 1% dew point line shown in figure 1 attached) then begin vacuum filling.

If the Dew Point test results are unsatisfactory, then apply 1 Torr of vacuum for 18 hours or longer. Apply 3 psi pressure of dry air (see Bill of Material) to the transformer and hold pressure for 24 hours. Repeat Dew Point Test. If the Dew Point results are satisfactory then begin vacuum filling. If the results are unsatisfactory then repeat this step or consult in your engineer.

Once the Dew Point is satisfactory, begin vacuum filling. Prior to oil filling, take a sample of the oil to check for dielectric strength and moisture. The dielectric strength should be > 30 kV when tested to ASTM D877, and the water content < 25 ppm.

Connect the filler hose to the bottom of the transformer and the vacuum hose to the top. Apply 1 Torr of vacuum on the empty transformer and hold for the appropriate time until stabilized. Once achieved begin hot oil filling (have oil between 40°C and 75°C) using heaters capable of achieving 75 degrees. Maintain at least 2 Torr of vacuum during filling. Allow time for the oil to cool down and top up as necessary. After filling allow a standby time of 36 hrs before energizing.

9.0 Oil Sampling and Analysis

After the transformer has been de-energized and prior to any work being started, an oil sample must be taken. Refer to checklist (Standard Oil Test Form) for what tests need to be performed.

Prior to filling the transformer, the oil must be tested to assure no contamination has occurred. (Perform dielectric and moisture tests at site)

Prior to energizing the transformer an oil sample should be taken to assure quality of work and oil. (Also perform DGA test)

After a determined period of time that the transformer has been in service an oil sample should be taken to reassure the integrity of the transformer.

10.0 Cleaning of Badly Contaminated Areas

Clean all oil and debris off the tank and radiators. Remove all the rust and prepare the areas for primer and top coat (See Bill of Material). On badly rusted areas use a needler/scaler. In less protected areas of the transformer use a wire brush or scraper type tool to remove the rust and to not damage other parts. Prior to applying primer make sure that all rust and oil have been removed. Apply primer and allow ample time to dry. After the primer is dry then apply the top coat (See Bill of Material). (Refer to Original Assessment: Action 7)

11.0 Testing

After completion of work, conduct a winding resistance and polarity test on the transformer. Perform an applied voltage and functionality test on the control wiring that has been changed. (Refer to Original Assessment: Action 10)

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12.0 Bills of Material

Item	Description	Special Notes
Nitrile Gaskets	"O" Ring and Flat	To be supplied by Alstom
Galvanized Steel Rigid Conduit	straight pipe	
Liquid Tight Flexible Conduit	Final Connections used in place of 90˚ bends	
14 AWG Stranded Copper Wire	Type SIS, 600 V Rating with black insulation	
10 AWG Wire	Current Transformer Circuit Leads	
12 AWG Wire	Jumpers	
41 Strand Extra Flexible Wire	Used for any Wiring that is 12 AWG or larger	
Wire Connectors	Nylon Insulated Sleeve Ring-Tongue Compression	
Dry Air	Minimum -50°C Dew point	
Dry Nitrogen	100% Dry Nitrogen	Only necessary for welding
Safesol Solution	Cleaning Solvent	
Benjamin Moore KP1470	Primer	
Benjamin Moore KP2273	Top Coat	

13.0 Specialized Tooling and Equipment

Prior to all work be started, equipment and tools should be readily available to avoid stoppage of work.

- A Vacuum Pump => 150CFM capacity and capable of attaining a blank off pressure of 0.1 Torr or more (Oil Reclaimer provided by Newfoundland Hydro)
- A suitable vacuum gauge
- An Oil Processor with a suggested flow rate of 4500 Lph or higher and a heater system to heat the oil up to 75°C (Oil Reclaimer provided by Newfoundland Hydro)
- Minimum 1"Oil and 2" Vacuum hoses, suitable for mineral oil and the specified vacuum levels
- Storage container to hold 35 000 L of oil
- Man Lift capable of reaching the top of the bushings and a Crane with a lifting capability of 5000lbs
- Torque Wrench with the capability of 350 ft-lbs and Gasket Cutter
- Protective covering for over the transformer while inside components exposed

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14.0 General Information

Torque specifications for bolted joints

Diameter (inches)	Torque (ft.-lbs.) Studs and Mild Steel Bolts	Torque (ft.-lbs.) Hi Strength Steel Bolts
0.375	17	--
0.500	35	55
0.625	70	105
0.750	120	190
1.000	175	450
1.250	350	780
1.500	600	1350

The High-Strength bolt head is identified by three lines spaced 120 degrees apart

Calculation for temperature change during pressure test

Measure the tank temperature half way up the shaded side of the tank. Measure the tank pressure with a gauge that is calibrated in .1 lb graduations. These values are the initial pressure and temperature values, P1 and T1. After pressure is added, let the transformer set overnight and calculate the pressure change due to temperature. In order to determine the pressure change due to temperature, conversion to absolute pressure must be done. The formula for calculating the pressure change P2 due to temperature change T2 is: P2 = P1 x T2/T1. Below is an example of how to use this formula.

- Example:
    - What will the pressure change in 10˚C drop in temperature? The transformer is left at 4:00 pm at a pressure of **5 psig** and a temperature of **22˚C**. At 8:00 am the next morning, a period of 16 hours, the tank temperature is 12˚C. What should the pressure be on the transformer? P2 = P1 x T2/T1
    - Calculation:
    - P2 = (14.7 psi + **5 psig**) (273˚ + **22˚C**) = 19.03 psi
    - P2 calculated = 19.02 psi – 14.7 psi = 4.3 psig
    - There for the pressure at 8:00 am is 4.3 psig

Reference to <u>Terminals Engineering Standard Outdoor Power Transformers</u>

2.61 All wiring shall be a minimum of No. 14 AWG stranded copper, type SIS, 600 V rating with black insulation. Current transformer circuit leads shall be a minimum of No. 10 AWG, except for jumpers which shall be No. 12 AWG. Wiring No. 12 AWG and larger shall be 41 strand extra flexible.

2.62 All wiring shall be terminated with nylon insulated sleeve ring-tongue compression type connectors. Spade type lugs shall not be acceptable. Soldering of terminal lugs shall not be permitted. No more than two leads shall be connected to any one stud or terminal. Each stud or terminal shall be furnished with a plain washer, lock washer and nut. All internal wiring shall be terminal to terminal. Splices and tee connections shall not be acceptable.

All internal wiring shall be terminated on one side of the terminal strips. The other side of the terminal strip shall be left free for Purchaser's eternal wiring. This shall be clearly indicated in manufacturer's diagrams.

2.65 Rigid galvanized steel conduit shall be used for all exterior wiring. Final connections to devices may be made using liquid tight flexible conduit suitable for any outdoor corrosive marine environment. Grounding continuity shall be maintained by running separate insulated ground wires in all conduits. All conduit fittings, junction boxes and connections shall be watertight.

15.0 Timeline for Repairs

Pressure Test (Before Repairs)	24 hours	
Emptying Oil	8 – 12 hours	Depending on Oil Reclaimer
High Voltage Bushing Replacement	8 – 16 hours	Depending on internal connections
Low Voltage Bushing gasket Replacement	8 – 16 hours	
Cover Gasket (Scenario One)	16 - 40 hours	
Cover Gasket (Scenario Two)	8 – 24 hours	
Control Panel and Conduits	4 - 8 hours	Depending on severity of leaks in the conduit and through wire
Radiators and Valves	24 – 40 hours	
Other Valves and Plugs	1 – 4 hours	Depending on findings from Pressure Test
Vacuum Filling/ Oil Processing	3 – 4 days	Depending on Dew Point test
Cleaning of Contaminated Areas	8 – 16 hours	Depending on condition of tank
Testing	4 – 8 hours	

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16.0 Original Assessment

NALCOR INDVIDUAL TRANSFORMER WORK SCOPES

Transformer T6

Action:

1 Replace the cover gasket and all bolts joining the tank cover and flange with new rust protected ones. Alternatively, weld a new steel channel over the existing joint and fasteners to completely seal the joint area
2 Drain and remove all the radiators, remove the drain valves and air release plugs, remove all rust from the area and replace with new fittings
3 Re-attach the radiators with new gaskets, and new fasteners
4 Empty the Silica Gel Breather and replace with new Silica Gel to the proper levels or alternatively add an appropriately sized Drycol breather (brochure attached to this report)
5 Drain all oil from transformer and reprocess before replacement (timing will depend on type of cover to flange joint repair)
6 Remove all oil from the main control box, and clean away all foreign debris
7 Clean the outside of the tank and radiators as thorough as practical, and repaint all extremely rusted areas
8 Perform a 24 hour pressure test to confirm the integrity of the repaired bolted and gasketed joints
9 Take oil sampled, and conduct standard oil tests as well as DGA
10 Test control wiring as necessary to ensure adequacy of the replaced circuitry
11 Empty the Silica Gel Breather and replace with new Silica Gel to the proper levels

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Standard Oil Sample Form

ALSTOM STANDARD and OPTIONAL TESTS for MINERAL OILS & SILICONE FLUIDS in NEW or SERVICE AGED TRANSFORMERS

Standard Test Package for all transformers:

- ■ Dielectric Strength to ASTM D1816 (2 mm gap) *
- ■ Dielectric strength to ASTM D877
- ■ Power Factor to ASTM D924 @ 25
- ■ Interfacial Tension to ASTM D971 *
- ■ Color to ASTM D1500 *
- ■ Neutralization Number to ASTM D974
- ■ Water Content to ASTM D1533
- ■ Visual Inspection to ASTM D1524 (oil) or D2129 (silicone)
- ■ Specific Gravity to ASTM D1298

Optional Tests:

- ☐ Dissolved Gas Analysis to ASTM D3612
- ☐ Corrosive Sulphur to ASTM D1275 *
- ☐ PCB Content to ASTM D4059
- ☐ Oxidation Inhibitor Content to ASTM D2668 *
- ☐ Oxidation Stability to ASTM D2440 & D2112 *
- ☐ Kinematic Viscosity @ - 40 C to ASTM D445
- ☐ Furan concentrations to ASTM D5837
- ☐ Particle Count to ASTM D6786
- ☐ Power Factor to ASTM D924 @ 100 C
- ☐ Fire & Flash Point to ASTM D92

Notes: a) Other tests available from the supplier at time of shipment.
b) Tests marked with * are not performed on Silicone Fluids

Form 202 January 5, 2011

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Figure 1

Job Number	
Tester	
Moister %	
Transformer Pressure psi	
Transformer Dewpoint °C	
Transformer Ambient °C	

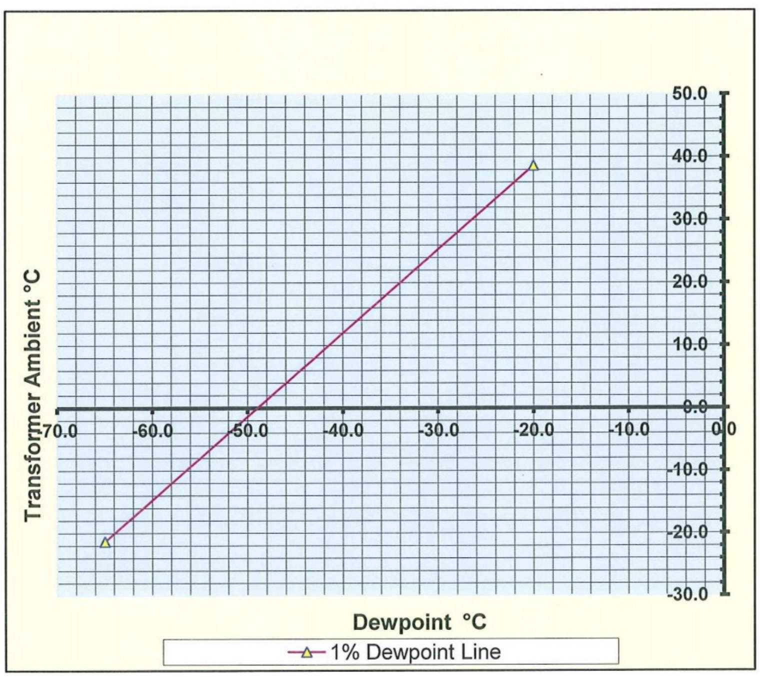

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Diagram 1
Low Voltage Side

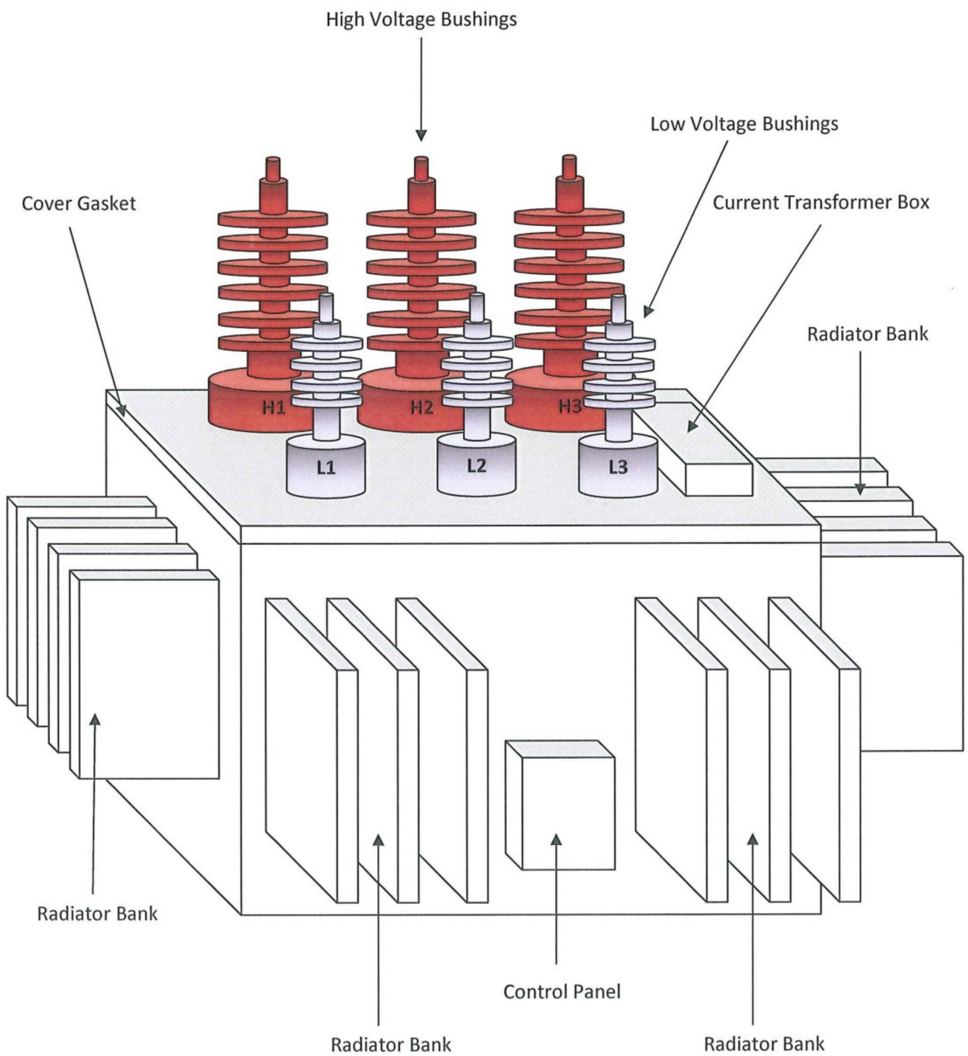

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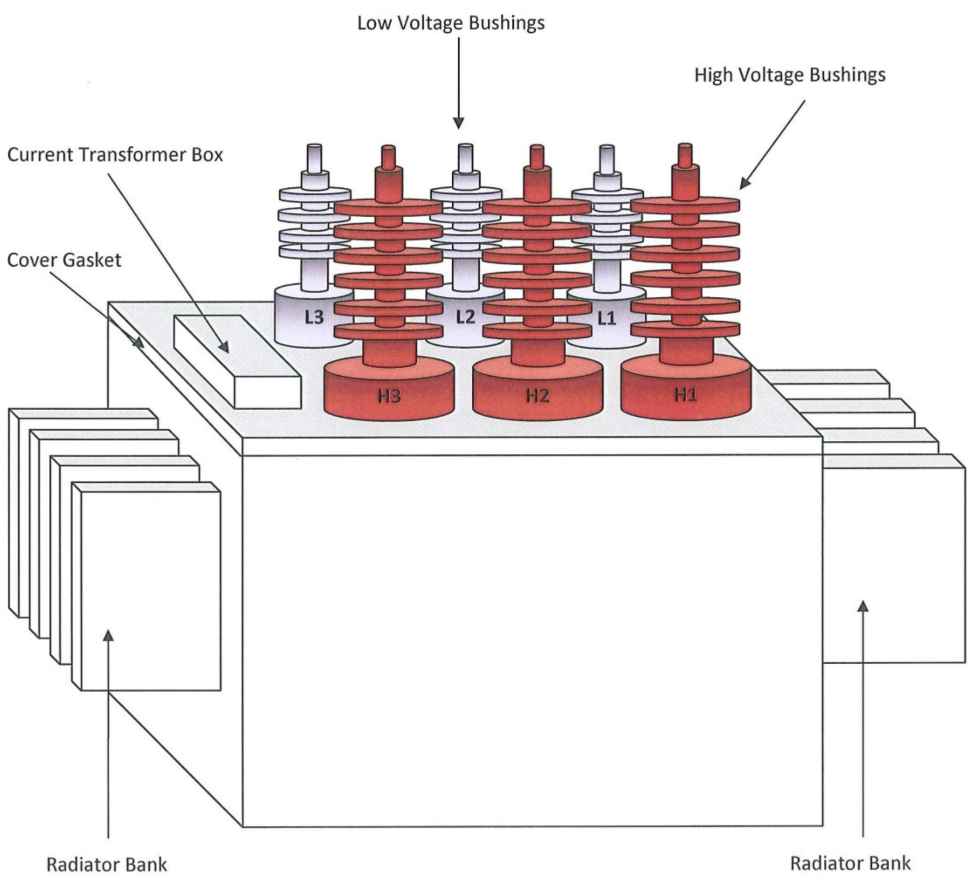
Diagram 2
High Voltage Side



Newfoundland & Labrador

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF THE

2015 CAPITAL BUDGET APPLICATION

FILED BY

NEWFOUNDLAND AND LABRADOR HYDRO

DECISION AND ORDER OF THE BOARD

ORDER NO. P.U. 50(2014)

BEFORE:

Andy Wells
Chair and Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

James Oxford
Commissioner

NEWFOUNDLAND AND LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

AN ORDER OF THE BOARD

NO. P.U. 50(2014)

IN THE MATTER OF the *Electrical Power Control Act, 1994,* SNL 1994, Chapter E-5.1 (the "*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the "*Act*"), as amended, and regulations thereunder; and

IN THE MATTER OF an application by Newfoundland and Labrador Hydro for an Order pursuant to Section 41 of the *Act* approving:

(a) its capital purchases and construction projects in excess of $50,000 beginning in 2015;

(b) its 2015 Capital Budget; and

(c) its estimated contributions in aid of construction for 2015 in the amount of $300,000.

BEFORE:

Andy Wells
Chair & Chief Executive Officer

Darlene Whalen, P. Eng
Vice-Chair

James Oxford
Commissioner

TABLE OF CONTENTS

I BACKGROUND

1. The Application

Newfoundland and Labrador Hydro ("Hydro") filed its 2015 Capital Budget Application (the "Application") with the Board of Commissioners of Public Utilities (the "Board") on August 1, 2014, requesting the Board make an Order approving:

(i) its 2015 capital purchases and construction projects in excess of $50,000;
(ii) its 2015 Capital Budget of $79,931,000;
(iii) its 2015 leases in excess of $5,000; and
(iv) its estimated contributions in aid of construction for 2015.

Notice of the Application, including an invitation to participate, was published on August 16, 2014. The Application and related documentation was made available on the Board's website.

Intervenor submissions were received from: i) the Consumer Advocate Mr. Thomas Johnson; ii) Newfoundland Power Inc. ("Newfoundland Power"); iii) Corner Brook Pulp and Paper Inc., North Atlantic Refining Ltd, and Teck Resources Limited (the "Industrial Customer Group"); and, iv) Vale Newfoundland and Labrador Inc. ("Vale").

A total of 232 Requests for Information ("RFIs") were initially issued to Hydro by the Consumer Advocate, Newfoundland Power, the Industrial Customer Group and the Board. On September 12, 2014 Hydro filed an additional report *Upgrade Circuit Breakers* along with revisions to the Application. On September 19, 2014 Newfoundland Power issued an additional seven RFIs to Hydro. Hydro responded to all RFIs by October 1, 2014.

On October 7, 2014 Hydro filed an amendment to its proposed 2015 Capital Budget, along with associated revisions to the Application, to reflect the withdrawal of the project C-25, Purchase Spare Transformer Paradise River, which proposed a $160,000 capital expenditure for 2015.

The intervenors did not file additional evidence and did not request a technical conference or oral hearing of the Application. Written submissions were filed by the Consumer Advocate, Newfoundland Power and the Industrial Customer Group on October 8, 2014. Vale advised it would not be filing a written submission. Hydro filed its reply submission on October 15, 2014.

On November 25, 2014 Hydro filed a letter advising that it was withdrawing the project D-313, Install Additional Washrooms, which proposed a $259,300 capital expenditure for 2015.

The revised proposed 2015 Capital Budget is $76,832,900.

2. Board Authority

Section 41 of the *Act* requires a public utility to submit an annual capital budget of proposed improvements or additions to its property for approval of the Board no later than December 15th in each year for the next calendar year. In addition, the utility is also required to include an estimate of contributions toward the cost of improvements or additions to its property which the utility intends to demand from its customers. Subsection 41(3) prohibits a utility from proceeding with the construction, purchase or lease of improvements or additions to its property without the prior approval of the Board where (a) the cost of the construction or purchase is in excess of $50,000, or (b) the cost of the lease is in excess of $5,000 in a year of the lease.

II PROPOSED 2015 CAPITAL BUDGET

In accordance with the legislation, regulations and Board guidelines Hydro provided detailed information supporting the overall capital budget for 2015 as well as the proposed individual project expenditures, including a project description, justification, costing methodology and future commitments, if applicable. In compliance with previous Board Orders the Application also includes specific information required to be filed, including a report on 2014 capital expenditures, a schedule of capital expenditures for the period 2010-2019, and a five-year capital plan for the period 2015-2019. The Application also includes a status report *Holyrood Overview: Future Operation and Capital Expenditure Requirements* (the "Holyrood Overview Report")as directed by the Board in Order Nos. P.U. 5(2012), P.U. 4(2013) and P.U. 42(2013).

1. Overview

The proposed 2015 capital expenditures are as follows:

2015 Proposed Capital Expenditures* ($000s)	
2015 Single Year Projects	
Generation	$10,508.4
Transmission and Rural Operations	22,377.1
General Properties	3,746.8
Allowance for Unforeseen Events	1,000.0
Total projects under $50,000	953.6
Multi-year (2015 Expenditures)	
Multi-year projects commencing in 2015	22,556.6
Multi-year projects commencing in 2014	14,095.8
Multi-year projects commencing prior to 2014	1,594.6
Total 2015 Capital Expenditures*	**$76,832.9**

*Does not include 7 additional projects with proposed 2015 capital expenditures totalling $194 million, filed separately for Board approval.

The Application requests approval of 107 capital projects which, according to Hydro, address both the need to sustain the existing asset base and to grow the asset base in response to increasing customer demand. Hydro advises that it proposes no new leases for 2015 in excess of $5,000 per year.

The proposed 2015 capital expenditures of $76,832,900 includes $22,556,600 in capital expenditures for multi-year projects that will start in 2015, $14,095,800 for capital projects that started in 2014 and will carry over into 2015, and $1,594,600 for projects that started prior to 2014. The Application states that 65.6% of the proposed 2015 capital expenditures relates to transmissions and rural operations, 22.6% relates to generation replacement of plant, and 10.5% is for general properties.

2. Level of Capital Expenditure

The Application (page H-1) sets out the actual capital expenditures from 2010-2013 and the forecast capital expenditures for 2014-2019, as below:

Actual Capital Expenditures (2010-2013)
($000s)

2010	2011	2012	2013
55,553	63,116	77,252	84,755

Forecast Capital Expenditures (2014-2019)[1]
($000s)

2014[2]	2015	2016	2017	2018	2019
279,020	274,249	313,640	223,371	169,708	66,704

Over the period 2010-2013 the average annual capital expenditure was approximately $70.2 million while for the period 2014-2019 the average annual capital expenditure is expected to be in the range of $220 million. Hydro states that the increase in overall capital expenditure reflects inflation, the requirement for specific projects related to replacement and upgrade of deteriorating facilities, ensuring compliance with legislation, and additions required to meet load growth. These estimates include significant expenditures for new generation and transmission assets, specifically for the upgrade of the transmission line corridor between Bay d'Espoir and Western Avalon, the construction of a third transmission line in from Churchill Falls to the Wabush Terminal Station, and the remaining costs for addition of a new combustion turbine at Holyrood.[3] In total, over the next five years, Hydro plans to spend close to $1.1 billion on plant and equipment.

Newfoundland Power submits that the principal question for the Board is whether Hydro's proposed capital expenditures in 2015 and 2016 are reasonably required for Hydro to meet its statutory obligation to provide reasonably safe and adequate, least cost service to its customers, including Newfoundland Power.

The Consumer Advocate submits that a utility bears the onus of establishing to the Board that the expenditures proposed are necessary for the year in which they are proposed, and that the expenditures represent the least cost alternative for providing electricity in the province.

The Industrial Customer Group submits that in the context of the 2015 Capital Budget Application, the lowest possible cost principle can only be given meaningful effect if Hydro's justifications for its proposed capital expenditures are subjected to a full and rigorous review.

[1] Forecasts for 2014 and 2015 have not been adjusted to reflect withdrawal of projects by Hydro.
[2] Includes proposed projects already filed but not yet approved in 2014 as well as projects to be filed (as of August 2014).
[3] These projects are or will be the subject of separate filings before the Board. The total capital expenditure for these projects over the 2014-2019 period is estimated at approximately $740 million (2015 Capital Plan, page A2).

This will ensure that Hydro's customers are being provided power in accordance with the power policy of the Province as set out in section 3 of the *EPCA*. The Industrial Customer Group also submits that the increased level of capital expenditure on hydraulic plant should be subject to an assessment of whether their relative cost-to-benefit relationship is consistent with the power policy of the Province. They note that Hydro acknowledges that the power policy of the Province places a responsibility on Hydro to continue the study of the existing system and alternatives, and that such study could result in decisions in the future to retire existing facilities. The Industrial Customer Group point out that the impact of the Labrador Infeed and the Maritime Link on what was an isolated system will be unprecedented, stating:

> *In the interim, the Board should consider whether capital expenditures on Island hydraulic generation assets can be at least reasonably deferred, until the impact of the Labrador Infeed and the Maritime Link can be assessed, in the context of the Island consumer demand for power that will need to be served at that time.*

The Board notes that the proposed capital budget for 2015 of $76,832,900 is only for projects for which approval is requested in this Application. This proposed 2015 capital budget is not reflective of the actual level of capital spending forecast for 2015, which Hydro states to be approximately $275 million. This is also the case for the forecast capital spending for 2014, which is estimated at approximately $279 million compared to the 2014 capital budget of $97.8 million approved in Order No. P.U. 42(2013). The primary reason for this difference is the number of supplementary capital expenditure approvals requested outside the capital budget application. The level of capital expenditure underway and forecast for the next few years is unprecedented but the Board notes that necessary new generation and transmission assets comprise a significant portion of these increased expenditures. Once these projects are completed the levels of capital spending should drop, as is shown in the forecast capital spending of $67 million for 2019. The Board will continue to rigorously review and monitor Hydro's capital expenditures, including requiring Hydro to provide full and detailed justification for proposed expenditures, with a view to ensuring that only those expenditures that are necessary and required for the provision of safe, adequate and reliable service are undertaken.

3. Holyrood Capital Spending

In Order Nos. P.U. 5(2012) and P.U. 4(2013) the Board directed Hydro to file, in conjunction with the 2014 Capital Budget application, an overview in relation to the proposed capital expenditures for the Holyrood Thermal Generating Station. In that application the Industrial Customer Group and Vale both raised concerns about the increasing level of capital expenditure at Holyrood in the context of its planned substantial shutdown in 2017 with the interconnection of the Muskrat Falls Generating Station. In Order No. P.U. 42(2013) related to Hydro's 2014 Capital Budget the Board found:

> *The Board agrees that the planned capital expenditures for Holyrood over the period 2014-2018 are significant, especially given the fundamental change in the role of the facility over the next 4-8 years. In considering the proposed capital projects for Holyrood the Board must be satisfied that each project and associated expenditure is necessary to ensure the safe and reliable operation of the plant and that all available alternatives have been examined. There may be capital projects that, in the normal course of operations, would be justified but may not be so in the context of a definite end-of-life date for the existing configuration and use of the plant. The burden of proof*

rests with Hydro to ensure that, over the next 4-8 years, all capital projects proposed for Holyrood have been subject to an enhanced level of scrutiny and review prior to inclusion in the capital program and to demonstrate that all alternatives, including the status quo, have been considered. The Board will also require Hydro to update and file the Holyrood Overview report with future capital budgets.

In the updated *Holyrood Overview Report* filed with this Application Hydro confirms that Holyrood is still intended to be used for primary generation until the interconnection with Muskrat Falls in 2017, and then be fully available for generation in stand-by mode until the 2020-2021 time frame. The specific phases of operation are as follows:

- Phase 1 (2014 through mid-2018): All three units are available for generation with Unit 3 also available for synchronous condenser operation.

- Phase 2 (mid 2018 to the 2020-2021 time frame): Units 1 and 2 are in standby generation mode and Unit 3 is operated in synchronous condenser mode but available for conversion to generation mode as required.

- Phase 3 (Post 2020-2021 time frame): Unit 3 continues to operate as a synchronous condenser only to the end of its useful life.

Hydro states that it has been concentrating on condition assessments and the formulation of requirements to get Holyrood to the end of its life as a generating facility, and for Unit 3 to operate in synchronous condenser mode beyond that time. The 2015 capital plan for Holyrood includes seven projects requiring approximately $3,684,000 in capital expenditures, which Hydro states are required to ensure that the Holyrood facility is available to operate at full production through the construction and commissioning of the Muskrat Falls development and the Labrador-Island Link. These projects include upgrading the powerhouse roofing, upgrading Quarry Brook Dam equipment, replacing DC distribution panels and breakers (stage 2), upgrading fire protection at the main warehouse, overhaul of the boiler feed pump east Unit 1, overhaul of extraction pumps, and overall of Unit 1 turbine valves. Of these projects only the work involving the overhauls of the boiler feed pumps, extraction pumps and turbine valves is not needed for Phase 3 operations. In terms of the total Holyrood expenditures for the 2015-2019 period Hydro advises that it forecasts a five-year capital expenditure of $41 million. The highest level of annual expenditure of approximately $21 million is forecast for 2016 during which significant work on Unit 3 is planned.

As stated previously in this Decision and in Order No. P.U. 42(2013), the level of Hydro's forecast capital expenditures for the next few years is unprecedented. The Board's findings in Order No. P.U. 42(2013) as shown above are still relevant and important, especially in the context of the significant changes in the way electricity will be supplied on the Island Interconnnected system. The additional information provided in the *Holyrood Overview Report* is critical in assisting both the Board and intervenors to understand the need for and scope of proposed Holyrood projects and in ensuring that only those projects that are fully justified as required and necessary are approved. The Board will continue to require Hydro to update and file the *Holyrood Overview Report* with future capital budgets, at least until the Holyrood Thermal Generating Station enters the Phase 3 operational stage.

4. Capital Projects Over $50,000

The Board's Capital Budget Guidelines set out the detailed requirements with respect to projects over $50,000. Each of these projects must be classified and segmented by materiality. They must also be defined as clustered, pooled or other, and classified as mandatory, normal or justifiable. A project classified as mandatory is one which the utility is obliged to carry out as the result of legislation, Board Order, safety issues or environmental risk. A normal capital expenditure is one that is required based on identified need or historical patterns of repair and replacement. Justifiable expenditures are proposed based on the positive impact the project will have on the utility's operations. As set out in Section F of the Application approximately 89% of the projects in Hydro's 2015 Capital Budget are classified as normal.

Newfoundland Power, the Consumer Advocate and the Industrial Customers all raised concern with Hydro's proposed 2015 and 2016 capital expenditure of $1,550,800 to replace the accommodations facility and septic system at its Ebbegunbaeg structure. The Consumer Advocate and the Industrial Customer Group also raised specific concerns and objections in relation to the proposed 2015 project to refurbish the generation unit at Snook's Arm. The Industrial Customer Group also questioned Hydro's proposed 2015 project to refurbish the Cat Arm Access Road.

Hydro advised by letter on November 25, 2014 that it was cancelling the multiyear project "Install Additional Washrooms" in Transmission and Rural Operations. This project was first approved in Order No. P.U. 4(2013) and was proposed to install additional washrooms at various Hydro terminal stations over a 15-year period. The purpose of the additional washrooms was to accommodate employees of both genders who are required to work at these sites. Hydro applied for and obtained a variance from section 61.2(c) of the Newfoundland and Labrador Occupational Health and Safety Regulations. This means that Hydro is able to utilize a single washroom facility to satisfy washroom requirements of workers at existing remote sites and that male and female washroom facilities would be incorporated into new facilities or as part of major renovations. The impact of this project cancellation is a reduction of $251,000 in the 2014 capital budget and $259,300 in the 2015 capital budget, as well as future expenditures planned for this 15-year project. The Board has incorporated this project cancellation into the 2015 capital budget totals.

The Application also includes Phase 1 engineering costs incurred in 2014 specific to 2015 capital projects put forth in this Application. Hydro states that only Phase 1 costs exceeding $1,000 have been included and that Phase 1 costs related to any specific project not receiving Board approval will not be capitalized. The total Phase 1 engineering costs included in the 2015 capital budget is $270,800.

The following sections set out the Board's considerations and findings for Hydro's proposed capital projects to be completed in 2015 and Hydro's proposed multi-year projects to commence in 2015, as well the concerns and objections raised by the intervenors for specific projects.

i. Projects to be completed in 2015

The Board has reviewed the proposed 2015 capital projects in excess of $50,000 to commence and be completed in 2015, the reports filed in support, the additional information filed by Hydro in response to RFIs, and the final submissions. The Board has completed its own independent examination and analysis of the Application and is satisfied that all the projects, as well as the Phase 1 engineering costs included in the 2015 capital budget, with the exception of those projects addressed specifically below, are adequately justified and are appropriate and necessary in the circumstances.

The projects identified and discussed below are those on which the intervenors or the Board raised questions and/or made submissions.

<u>Refurbish Access Road – Cat Arm (C-15: $990,000)</u>

Hydro proposes to refurbish the 24 km long access road to the Cat Arm Hydroelectric Generating Station, situated on the east side of the Great Northern Peninsula. The project consists of replacing culverts at various locations and processing, supplying, placing and compacting 100 mm of Class 'A' road topping over the entire surface of the road. According to Hydro, after 30 years of continuous use and regular maintenance, the road now requires upgrading to extend its service life and to provide safe and reliable access to the station. This project is justified by Hydro on the basis that it is essential for operation and maintenance of the plant and that it must be kept in safe and passable condition to ensure both employee and public safety.

The Industrial Customer Group questions whether this capital improvement should be paid for by Hydro's customers since Hydro's legal interest in the road is in the form of a crown easement only and that the road is open for public use. According to the Industrial Customer Group the proposed capital expenditure *"would result in improvements to an asset which Hydro will not own or even hold as a long term leaseholder, but merely have a right of access over."* The Industrial Customer Group also submits that *"public use of the access road, and any consequent risk to the public, is not a valid justification for a capital expenditure by Hydro to be borne by its rate payers."* The Industrial Customer Group submits that the evidence demonstrates that the road continues to be useable and is used on a daily basis by plant personnel, and that no evidence has been presented to show that the condition of the road has affected, or will affect, the reliability or efficiency of power generation at the plant. There is also no evidence that calls into question whether the road can be used safely. The Industrial Customer Group submits that this project does not meet any reasonable test of necessity for reliable service, at the lowest possible cost, to Hydro's customers and that approval of this project should be denied.

Newfoundland Power and the Consumer Advocate did not make submissions on this project.

In its reply submission Hydro notes that this project is similar to others the Board has approved in recent years. With respect to the issue of Hydro's customers paying for the upgrade of a road used by the public Hydro states that this might be a valid perspective if there was evidence that such use is extensive or was the cause of much deterioration of the road. Hydro states that the evidence is that the road is used daily by plant personnel and regularly by its maintenance staff, and that it is the combination of this use and public use that has resulted in vehicle wear and decreased safety. According to Hydro the road must be maintained as passable and safe to allow access to the Cat Arm Plant by Hydro's employees and contractors. Hydro also suggests:

> *The Board may take notice that the incidental use by the public of roads that provide access to remote areas for recreational uses is not uncommon regardless of whether the roads were built by either of the electrical utilities or by other industries such as forest industry companies.*

Hydro also disagrees with the Industrial Customer Group that its easement for the road is insufficient or inadequate for its purposes or should disentitle Hydro from including the costs of this project in its rate base. Hydro states:

> *While it is true that exclusive title to the road would enable Hydro to prevent others from using the road, Hydro has neither need nor present intention to exclude the public from using the road so obtaining such a form of title is unnecessary and should not be a prerequisite to its inclusion in rate base.*

The Board is satisfied that this project should be approved. The evidence demonstrates that this road is utilized daily by plant personnel and regularly by Hydro's maintenance staff and contractors. The Board agrees that the road is essential for the operation and maintenance of the 127 MW Cat Arm Generating Station and must be kept in a safe and passable condition.

The issue raised by the Industrial Customer Group with respect to the nature of Hydro's legal interest in the road in the form of a Crown easement has already been addressed by the Board. In Order No. P.U. 24(2012) the Board approved a capital expenditure in the amount of $492,100 for slope stabilization work on the Cat Arm Road. In response to concerns raised around Hydro's legal interest in the public road, the Board also ordered that Hydro could not include the expenditure in its rate base until the Board confirmed in writing that to do so would be consistent with generally accepted sound public utility practice. On December 17, 2013 Hydro filed a copy of a 50-year Crown Easement for the Cat Arm Road issued to Hydro under the Lands Act. The Board confirmed on March 4, 2014 that Hydro could now include the capital expenditure for the refurbishment of the Cat Arm Road in its calculation of rate base. The Board has accepted that Hydro's legal interest in the Cat Arm Road in the form of a Crown easement is in accordance with sound public utility practice. The matter of public access to the road does not, in the Board's view, affect the fact that the road must be maintained in the condition necessary to continue to provide reliable service from the Cat Arm Generating Station. This project will be approved.

<u>Refurbish Generation Unit – Snook's Arm (D-49; $352,900)</u>

Hydro proposes to undertake an assessment of the Snook's Arm generating station to fully identify the required scope of the refurbishment of this facility. The single unit at this station has a nameplate rating of 560 kW and was constructed in 1956 to provide electricity for a mining operation. Equipment issues resulted in the unit at Snook's Arm being de-rated in 2008 to 500 kW. The unit is operated continuously, except for maintenance. There have been no replacements of major components of the generating unit in the 57 years of operation. The wooden stave penstock was replaced with a steel penstock in 2006 at a total cost of $2.2 million. The assessment will include both electrical and mechanical evaluation of the unit, and a civil evaluation of the powerhouse. Hydro justifies this project on the basis of the requirement to refurbish the generating facility at Snook's Arm in order for Hydro to provide safe, least-cost, reliable electrical service to the Island Interconnected system.

In his submission the Consumer Advocate states that it is unclear what the actual scope or aim of this project is. While the Application references the 2015 expenditure of $350,900 as necessary to assess the required scope of work to refurbish this generating facility, the Consumer Advocate notes that, in its reply to CA-NLH-023, Hydro states that is seeking approval for a study to compare and consider the options of status quo, refurbishment, replacement or decommissioning so it can evaluate the economic feasibility of Snook's Arm. The Consumer Advocate submits that *"this project must be carefully considered and therefore deferred until further information is provided by Hydro as to its long-term plans for Snook's Arm, which appears to be refurbishment."*

The Industrial Customer Group submits that *"this proposed capital project is an example of Hydro's seeking to impose on its customers the costs of a planning exercise with dubious potential for benefit to those customers."* They note that Hydro could not provide an estimate of the system marginal cost of energy on a ¢ per kWh basis following the Labrador infeed for comparison with the levelized cost of energy sought in NP-NLH-019. They further question the economic analysis completed for the project, noting that Hydro states in CA-NLH-023 that the economic justification for the project is to "*compare and consider the options of status quo, refurbishment, replacement or decommissioning so it can evaluate the economic feasibility of Snook's Arm.*" The Industrial Customer Group submits:

> *The facility, as rated, is not an essential component of Hydro's generation capacity on the Island. Hydro may choose to commission this assessment, but it is submitted that the cost of such an assessment should not be approved as a capital expenditure to be included in Hydro's rate base unless (a) the assessment recommends that such a refurbishment is economically justified and (b) the Board, after due process, accepts such a recommendation.*

Newfoundland Power did not make submissions on this project.

In its reply submission Hydro clarifies that the proposed project is to determine specifically the works and costs associated with the refurbishment of the facility. Hydro states that this approach is being taken to ensure a cost effective and well planned project and further states that *"once the additional amount of information is available and before a proposal is made to proceed with this refurbishment, a cost/benefit analysis will be carried out to verify that it is economic."*

The Board is satisfied that this project should proceed as proposed. The assessment to be undertaken by Hydro is intended to provide information on the extent of the work required to refurbish the facility. This information will inform the decision by Hydro on whether refurbishment is a least-cost option or whether other options should be considered. This project will be approved.

ii. Multi-year projects to commence in 2015

Multi-year project approval allows a utility to proceed with large expenditures that span a number of years with the certainty that the whole project, including future year expenditures, has been reviewed and approved by the Board. This approval is important where the project and associated expenditure is so large that it cannot be completed in one year, and can also be important for planning and efficiency purposes where discrete projects are proposed together because of similar justification and need or because doing the work together is more efficient.

In the Application Hydro proposes 29 multi-year projects to commence in 2015. With the exception of one project all are scheduled to be completed in 2016. The capital expenditures associated with these multi-year projects totals $22,556,600 in 2015, $28,546,900 in 2016 and $245,100 in 2017 for a total expenditure of $51,348,600 over a three-year period.

The Board has reviewed the documentation and evidence on the record and is satisfied that the proposed multi-year purchase and construction projects in excess of $50,000 commencing in 2015, except the project discussed below, are adequately justified and are appropriate and necessary in the circumstances.

Replace Accommodations and Septic System, Ebbegunbaeg (C-48: $489,400 in 2015; $1,061,400 in 2016)

This project is proposed by Hydro to replace the existing site accommodations and septic system at Hydro's remote Ebbegunbaeg control structure. The existing accommodations facility was constructed in 1966 and consists of two permanently installed mobile units – a four person trailer and a two person trailer. This arrangement provides six bedrooms, three washrooms, a kitchen area, a dining area and a living room. Hydro states that the existing facility was deemed unsatisfactory in 2013 due to deteriorating building structure and mould growth. Hydro employees working at the remote Ebbegunbaeg site are now transported to and from the site by helicopter daily, instead of driving and staying on-site. Weather conditions can impact the ability to get in and out of the site via helicopter, which affects Hydro's ability to plan and schedule maintenance work. Hydro states that the transport of personnel by helicopter poses numerous logistical issues and cannot be accepted as a long term solution. The planned work includes completion of required road upgrades and a temporary bridge for construction access, site preparation and cribbing installation, supply and installation of a new double module accommodations complex for six persons, and installation of a new septic system.

Hydro justifies this project on the basis of the condition of the existing facility, and the fact that it does not meet current industry standards for camp facilities. Hydro states that modern day standards for such facilities provide adequate levels of comfort and privacy through single room occupancy, individual washroom facilities, separate female and male accommodations, and modern communications systems. Hydro proposes to construct a complex which will contain a kitchen/dining and a common area, a common washroom, laundry facilities, and six bedrooms each with its own washroom. In addition the existing septic system does not have registered provincial approval and will be replaced with a system that complies with all provincial requirements and has the required registered approval. The new facility will have an estimated service life of 35 years. (NP-NLH-043)

Newfoundland Power submits that Hydro has not shown that it has considered all reasonable alternatives for providing worker accommodations at the Ebbegunbaeg site and therefore has not established that the proposed expenditures are reasonable in the circumstances. Newfoundland Power points out that Hydro is unable to provide details regarding the number of staff and the times of overnight visits to the site for the five years prior to 2013. In addition Hydro is unable to provide details regarding the number of days employees have been transported to or from the

Ebbegunbaeg site via helicopter in 2013 and 2014. Newfoundland Power states that the evidence provided in the Application outlines typical standards for worker accommodations which tend to be occupied on a continuous basis, and that Hydro has not addressed the issue of whether generally accepted standards exist for intermittently used worker accommodations such as appear to be required at the Ebbegunbaeg site. According to Newfoundland Power *"At most, the evidence provided in support of the project establishes only that the existing accommodations have reached the end of their useful service life."* Newfoundland Power submits that Hydro's proposal is not consistent with the least cost provision of service to Hydro's customers.

The Consumer Advocate notes that Hydro is unable to provide information on either the frequency of use or the number of employees who made use of the current facilities overnight for the past five years. Hydro has also not provided any information as to the practices of other utilities which own and maintain such remote and infrequently used accommodations. The Consumer Advocate states that *"Hydro has not considered all options that are available for this site, particularly given that it may be used, at most, for 8 days a few times a year for maintenance"*. He submits that a complete evaluation of what is actually required at the site, including the need for double occupancy accommodations, should be considered. The Consumer Advocate submits that this project should be rejected at this time.

The Industrial Customer Group acknowledges that some expenditures may be required at the site to provide accommodations with a reasonable level of comfort, privacy and safety. However they note that, even though Hydro's position is that single room occupancy is the norm in a modern day workforce, there are no established national industry standards for onsite accommodation facilities. The Industrial Customer Group also notes that Hydro was unable to provide information as to the times and number of staff who stayed overnight at the site for the five years prior to 2013 or on the gender of staff staying at the site. The Industrial Customer Group submits:

> *"...that Hydro has failed to provide adequate justification for the expenditure of in excess of $1,500,000.00, when smaller accommodations (with partial double occupancy and/or containing less amenities (i.e. without seven (7) bathrooms to service a six (6) bedroom facility or a common/recreational area) would likely suffice.*

In its reply submission Hydro notes that the Intervenors have not questioned the need for accommodations at the site but take issue with the standard to which the accommodations are built. Hydro suggests that the information provided in NP-NLH-042 show that the challenged standard of the accommodations does not significantly affect the overall project costs. Hydro states:

> *It can be reasonably assumed that if accommodations are required for six employees that the overall size of the building, the footprint, would be broadly similar whether accommodations are provided in single or double occupancy accommodations. The savings that would be attributable to providing employee accommodations that are below the standard proposed would, therefore, likely be very modest indeed.*

With respect to the standard to which to build the facility Hydro looked to existing written standards in Alberta and British Columbia, as provided in NP-NLH-044. According to Hydro there is no evidence of a different standard applied for intermittent accommodations than for continuous accommodations. Hydro notes that this project is similar to another project undertaken by Hydro to provide reasonable intermittent accommodations at its Cat Arm site.

Based on the evidence the Board is satisfied that this project should be approved as proposed. The Board notes that there appears to be no objection to the need for the project but rather the concerns relate to the standards of the proposed accommodations. Hydro's evidence is that there is no established industry standard for onsite accommodations (NP-NLH-044). Hydro did reference written standards from Alberta and British Columbia which support its proposed single room configuration. Hydro states that the *"provision of a clean, well-kept accommodations facility which provides for gender segregation and the option of privacy for all workers help to mitigate the stresses associated with working away from home."* In the absence of evidence as to what other specific standard should be used, the Board accepts Hydro's proposed accommodation plan. The alternatives to replacing the existing accommodations facility are refurbishment or abandonment in favour of using helicopters to transport workers on a daily basis, both of which were shown to result in higher costs and, in the case of helicopter use, higher reliability and worker risk. The Board notes as well that the proposed accommodation facility is very similar to the project approved for accommodations facilities at the Cat Arm Generating Station in Order No. P.U. 36(2008). Hydro has justified this project on the basis of least-cost and the Board is satisfied that this project is in the best interest of Hydro's employees and customers. This project will be approved as proposed.

5. Conclusion

The Board finds that the proposed purchases and construction projects in excess of $50,000, including the multi-year projects proposed to start in 2015, are prudent, reasonable and necessary for Hydro to continue to provide safe and reliable service and should be approved. The Board also finds that the capital budget proposed in this Application for 2015 is prudent and reasonable and will, therefore, approve Hydro's 2015 Capital Budget in the amount of $76,832,900.

III CLAIM FOR COSTS

The Industrial Customer Group requests that the Board make an order for its costs of participation in the Application.

Hydro, the Consumer Advocate and Newfoundland Power did not comment on the request for cost award.

The Board has jurisdiction to award costs to a party under section 90 of the *Act*. Hydro did not make any argument with respect to the request for costs. The Board finds that the participation of the Industrial Customer Group contributed to its understanding of the issues in this Application and is satisfied that an award of costs, to be fixed by the Board, is appropriate. The Industrial Customer group will be required to submit a bill of costs to the Board within 30 days of the date of this Order.

IV ORDER

IT IS THEREFORE ORDERED THAT:

1. **Hydro's proposed construction and purchase of improvements or additions to its property in excess of $50,000 to be completed in 2015, as set out in Schedule A to this Order, are approved.**

2. **Hydro's proposed multi-year construction and purchase of improvements or additions to its property in excess of $50,000 to begin in 2015, as set out in Schedule B to this Order, are approved.**

3. **Hydro's proposed contributions in aid of construction for 2015 are approved.**

4. **Hydro's proposed 2015 Capital Budget for improvements or additions to its property in an amount of $76,832,900, as set out in Schedule C to this Order, is approved.**

5. **Unless otherwise directed by the Board Hydro shall file, in conjunction with the 2016 Capital Budget Application, an updated overview in relation to the proposed capital expenditures for the Holyrood Thermal Generating Station.**

6. **Unless otherwise directed Hydro shall file, in conjunction with the 2016 Capital Budget Application, a status report on the 2015 capital expenditures.**

7. **Unless otherwise directed by the Board Hydro shall file an annual report with the Board in relation to its 2015 capital expenditures by March 1, 2016.**

8. **The Industrial Customer Group is entitled to an award of costs in an amount to be fixed by the Board, with a cost submission to be filed by the Industrial Customer Group within 30 days of this Order.**

9. **Hydro shall pay all costs and expenses of the Board incurred in connection with the Application.**

DATED at St. John's, Newfoundland and Labrador this 2nd day of December 2014.

Andy Wells
Chair & Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

James Oxford
Commissioner

Cheryl Blundon
Board Secretary

Schedule A
Order No. P.U. 50(2014)
Single Year Projects over $50,000
Issued: December 2, 2014

NEWFOUNDLAND AND LABRADOR HYDRO
2015 CAPITAL BUDGET
SINGLE YEAR PROJECTS OVER $50,000
($000)

PROJECT DESCRIPTION		2015
GENERATION		
HYDRAULIC PLANT		
Refurbish Surge Tank - Bay d'Espoir	1,629.3	
Refurbish Access Road - Cat Arm	990.0	
Replace ABB Exciter Unit 2 - Cat Arm	845.9	
Automate Generator Deluge Systems Units 3,5 and 6 - Bay d'Espoir	645.2	
Upgrade Public Safety Around Dams and Waterways - Various Sites	483.9	
Install Hydrometeorological Stations - Various Sites	377.9	
Refurbish Generation Unit - Snook's Arm	352.9	
Upgrade Equipment Doors - Various Sites	348.5	
Replace Autogreasing Systems Units 2 and 4 - Bay d'Espoir	254.4	
Overhaul Turbine/Generator - Various Sites	304.4	
Replace Generator Bearing Coolers - Bay d'Espoir	153.8	
TOTAL HYDRAULIC PLANT		6,386.2
THERMAL PLANT		
Overhaul Turbine Valves Unit 1 - Holyrood	1,577.5	
Upgrade Powerhouse Roofing - Holyrood	1,047.8	
Upgrade Quarry Brook Dam Equipment - Holyrood	498.7	
Overhaul Boiler Feed Pump East Unit 1 - Holyrood	196.3	
Replace DC Distribution Panels and Breakers - Holyrood	127.9	
Overhaul Extraction Pumps - Holyrood	189.6	
TOTAL THERMAL PLANT		3,637.8
GAS TURBINES		
Replace Alternator Shaft - Happy Valley	484.4	
TOTAL GAS TURBINES		484.4
TOTAL GENERATION		10,508.4

TRANSMISSION AND RURAL OPERATIONS		
TERMINAL STATIONS		
Perform Site Work for Mobile Substation - Barachoix	489.3	
Upgrade Terminal Station Foundations - Various Sites	302.3	
Upgrade Control Wiring Phase 1 to Terminal Station 1 - Bay d'Espoir	301.0	
Install Support Structures C2 Capacitor Bank - Hardwoods	199.3	
Replace Surge Arrestors - Various Sites	198.1	
Upgrade Transformer Differential Protection - Grandy Brook	154.0	
TOTAL TERMINAL STATIONS		1,644.0
TRANSMISSION		
Perform Wood Pole Line Management Program - Various Sites	2,830.6	
TOTAL TRANSMISSION		2,830.6
DISTRIBUTION		
Provide Service Extensions - All Service Areas	6,080.0	
Upgrade Distribution Systems - All Service Areas	3,340.0	
Construct Second Distribution Feeder - Nain	1,050.3	
Relocate Voltage Regulator - Hawkes Bay	166.4	
TOTAL DISTRIBUTION		10,636.7
GENERATION		
Inspect Fuel Storage Tanks - Various Sites	1,761.1	
Increase Fuel Storage - Rigolet	1,666.8	
Overhaul Diesel Units - Various Sites	1,199.2	
Upgrade Building Exterior - Makkovik	309.5	
Increase Generation Capacity - Makkovik	272.6	
TOTAL GENERATION		5,209.2
PROPERTIES		
Upgrade Line Depots - Various Sites	953.3	
Install Fall Protection Equipment - Various Sites	198.9	
Upgrade HVAC System - Port Saunders	137.0	
Reshingle Roof - Stephenville	76.8	
TOTAL PROPERTIES		1,366.0
METERING		
Purchase Meters, Equipment and Metering Tanks - Various Sites	196.2	
TOTAL METERING		196.2
TOOLS AND EQUIPMENT		
Replace Light Duty Mobile Equipment - Various Sites	494.4	
TOTAL TOOLS AND EQUIPMENT		494.4
TOTAL TRANSMISSION AND RURAL OPERATIONS		22,377.1

GENERAL PROPERTIES		
INFORMATION SYSTEMS		
SOFTWARE APPLICATIONS		
New infrastructure		
Perform Minor Application Enhancements - Hydro Place	329.5	
Cost Recoveries	(141.6)	
Upgrade of Technology		
Upgrade Lotus Notes - Hydro Place	635.4	
Cost Recoveries	(273.1)	
Upgrade Energy Management System - Hydro Place	194.9	
Replace Customer Care System - Hydro Place	134.9	
TOTAL SOFTWARE APPLICATIONS		880.0
COMPUTER OPERATIONS		
Infrastructure Replacement		
Replace Personal Computers - Hydro Place	573.3	
Upgrade Enterprise Storage Capacity - Hydro Place	621.3	
Cost Recoveries	(267.0)	
Replace Peripheral Infrastructure - Hydro Place	200.5	
Upgrade of Technology		
Upgrade Server Technology Program - Hydro Place	601.3	
Cost Recoveries	(227.1)	
TOTAL COMPUTER OPERATIONS		1,502.3
TOTAL INFORMATION SYSTEMS		2,382.3
TELECONTROL		
NETWORK SERVICES		
Infrastructure Replacement		
Network Infrastructure		
Replace Network Communications Equipment - Hydro Place	169.5	
Upgrade of Technology		
Replace Telephone System - Springdale	132.7	
Replace WIFI Access Points - Various Sites	126.3	
Replace GDC Metroplex - Various Sites	69.2	
TOTAL TELECONTROL		497.7
ADMINISTRATION		
Replace Roof - Hydro Place	671.9	
Remove Safety Hazards - Various Sites	194.9	
TOTAL ADMINISTRATION		866.8
TOTAL GENERAL PROPERTIES		3,746.8
TOTAL SINGLE YEAR PROJECTS OVER $50,000		36,632.3

Schedule B
Order No. P.U. 50(2014)
Multi-Year Projects over $50,000
Issued: December 2, 2014

NEWFOUNDLAND AND LABRADOR HYDRO
2015 CAPITAL BUDGET
MULTI-YEAR YEAR PROJECTS OVER $50,000
($000)

Multi-year Projects Commencing in 2015

PROJECT DESCRIPTION	2015	2016	2017	2018	2019	Total
Refurbish Salmon River Spillway - Bay d'Espoir	745.6	556.8				1,302.4
Replace Station Service Breakers - Cat Arm	644.9	363.4				1,008.3
Upgrade Generator Bearings Units 1 and 3 - Bay d'Espoir	14.7	633.3				648.0
Replace Pump House and Associated Equipment - Bay d'Espoir	22.7	522.5				545.2
Refurbish Intakes - Bay d'Espoir	72.6	262.3				334.9
Install Infrared View Ports - Various Sites	83.7	113.1				196.8
Refurbish Unit Relay Protection - Paradise River	8.7	79.7				88.4
Upgrade Fire Protection (Main Warehouse) - Holyrood	46.2	197.6				243.8
Upgrade Gas Turbine Plant Life Extension - Stephenville	2,655.2	2,525.4				5,180.6
Upgrade Circuit Breakers - Various Sites (2015-2016)	6,189.1	6,873.8				13,062.9
Upgrade Power Transformers - Various Sites	4,440.4	7,002.3				11,442.7
Replace Disconnect Switches - Various Sites (2015-2016)	963.7	642.9				1,606.6
Install Transformer On line Gas Monitoring - Various Sites	700.5	975.7				1,676.2
Design and Install Fire Protection in 230 kV Station - Various Sites	67.6	424.3				491.9
Upgrade Terminal Station Protection and Control - Various Sites	172.7	307.2				479.9
Replace Station Lighting - Bay d'Espoir	16.7	160.3				177.0
Upgrade Distribution System - Various Sites (2015-2016)	1,136.1	818.8				1,954.9
Install Fire Protection System - Lanse Au Loup	220.6	1,126.2				1,346.8
Replace Unit 2038 - Mary's Harbour	103.5	1,241.5				1,345.0
Replace Programmable Logic Controllers - Various Sites	366.9	346.0	245.1			958.0
Replace Diesel Unit 254 - Paradise River	66.8	429.3				496.1
Upgrade Ventilation Systems - Various Sites	175.9	317.3				493.2
Install Disconnect Switches for Mobile Generators - Various Sites	10.0	189.3				199.3
Replace Accommodations/Septic System - Ebbegunbaeg	489.4	1,061.4				1,550.8
Legal Survey of Primary Distribution Line Right of Ways - Various Sites (2015-2016)	158.6	40.3				198.9
Install Automated Meter Reading - Various Sites (2015-2016)	559.9	401.8				961.7
Replace Off Road Track Vehicle Unit 7861 - Stephenville	1.1	397.8				398.9
Replace Vehicles and Aerial Devices - Various Sites (2015-2016)	2,377.1	225.3				2,602.4
Replace Cooling Tower and Auxiliaries - Hydro Place	45.7	311.3				357.0
TOTAL MULTI-YEAR PROJECTS OVER $50,000 COMMENCING 2015	**22,556.6**	**28,546.9**	**245.1**	**0.0**	**0.0**	**51,348.6**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 CAPITAL BUDGET
MULTI-YEAR YEAR PROJECTS OVER $50,000
($000)

Multi-year Projects Commencing in 2014 (Previously Approved)

PROJECT DESCRIPTION	2014	2015	2016	2017	2018	Total
Upgrade Burnt Dam Spillway - Bay d'Espoir	110.2	1,201.9				1,312.1
Upgrade Generator Bearings Unit 2 - Bay d'Espoir	18.9	396.0				414.9
Replace Spherical By Pass Valve Assemblies Units 1 and 2 - Bay d'Espoir	57.5	96.3				153.8
Replace Economizer Inlet Valves Units 1 and 2 - Holyrood	192.0	329.1				521.1
Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood	49.8	467.4				517.2
Install Fire Protection Upgrades - Holyrood	56.6	312.5				369.1
Install Handheld Pendant to Overhead Crane - Bay d'Espoir	49.9	170.8				220.7
Upgrade Circuit Breakers - Various Sites (2014-2015)	3,695.4	1,642.5				5,337.9
Replace Disconnect Switches - Various Sites (2014-2015)	815.9	189.5				1,005.4
Replace Optimho Relays on East Coast - Various Sites	89.1	96.9				186.0
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	1,191.7	988.2				2,179.9
Upgrade Distribution Systems - Various Sites (2014-2015)	370.2	4,850.1				5,220.3
Replace Recloser Control Panels - Various Sites	111.3	84.4				195.7
Install Fire Protection System - Nain	107.1	892.2				999.3
Upgrade Diesel Plant Production Data Collection Equipment - Various Sites	268.9	269.8	280.7			819.4
Legal Survey of Primary Distribution Line Right of Ways - Various Sites (2014-2015)	156.8	40.3				197.1
Install Automated Meter Reading - Various Sites (2014-2015)	356.9	340.2				697.1
Replace Battery Banks and Chargers - Various Sites	267.0	398.0				665.0
Upgrade IP SCADA Network - Various Sites	254.2	238.7				492.9
Replace Vehicles and Aerial Devices - Various Sites (2014-2015)	1,809.1	1,091.0				2,900.1
TOTAL MULTI-YEAR PROJECTS OVER $50,000 COMMENCING 2014	**10,028.5**	**14,095.8**	**280.7**	**0.0**	**0.0**	**24,405.0**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 CAPITAL BUDGET
MULTI-YEAR YEAR PROJECTS OVER $50,000
($000)

Multi-year Projects Commencing Prior to 2014 (Previously Approved)

PROJECT DESCRIPTION	2015
Replace Instrument Transformers - Various Sites	538.4
Perform Grounding Upgrades - Various Sites	345.4
Perform Arc Flash Remediation - Various Sites	413.1
Upgrade Microsoft Office Products - Hydro Place	297.7
TOTAL MULTI-YEAR PROJECTS OVER $50,000 COMMENCING PRIOR TO 2014	**1,594.6**

Schedule C
Order No. P.U. 50(2014)
2015 Capital Budget
Issued: December 2, 2014

NEWFOUNDLAND AND LABRADOR HYDRO
2015 CAPITAL BUDGET
($000)

Projects Over $50,000 to be completed in 2015	$36,632,300.00
Multi-Year Projects over $50,000 commencing in 2015	22,556,600.00
Multi-Year Project over $50,000 commencing prior to 2015 (previously approved)	15,690,400.00
Projects under $50,000[1]	953,600.00
Allowance for Unforeseen Items	1,000,000.00
Approved 2015 Capital Budget	**$76,832,900.00**

[1] Approval of projects under $50,000 is not required but these expenditures are part of the total 2015 Capital Budget

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