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September 5, 2023

Industrial Customers Group
c/o #301 – 2298 McBain Avenue
Vancouver, BC
V6L 3B1

Attention: Robert Hobbs

Dear Robert Hobbs:

Re: FortisBC Inc. (FBC)

Application for Approval of a Certificate of Public Convenience and Necessity for the A.S. Mawdsley Terminal Station Project (Application) ~ Project No. 1599424

Response to the Industrial Customers Group (ICG) Information Request (IR) No. 2

On February 24, 2023, FBC filed the Application referenced above. In accordance with the regulatory timetable established in BCUC Order G-70-23 and Exhibit A-9[1] for the review of the Application, FBC respectfully submits the attached response to ICG IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

[1] By letter dated August 23, 2023, the Panel granted FBC an extension to file its responses to IR No. 2 on Tuesday, September 5, 2023.

1. Reference: Exhibit B-4, BCUC IR 2.4

1.1 Please identify the events in the table that were caused by an issue with either transformer that resulted in a) an automatic protection trip, and b) a manual intervention trip to address the particular issue.

Response:

Please see the following table from the response to BCUC IR1 2.4 which has been revised to only include the events that were caused by an issue with either transformer that resulted in a) an automatic protection trip, and b) a manual intervention trip to address the issue.

Date	Element	Outage/ Failure	Status	Cause	Intervention Type
Nov. 20, 2018	ASM T2	Failure & Outage	Restored	Temperature gauge's well gaskets failed. Transformer oil leak from gasket. Repaired.	Manual
Dec. 20, 2018	ASM T1	Failure & Repair	Resolved	Alarm. Low oil in the main tank. Investigation and top-up completed.	Manual
Oct. 28 – Nov.1, 2019	ASM T2	Failure & Outage	Resolved	Transformer maintenance. Insulation power factor results indicated a deterioration of solid insulation. Multiple oil leaks at the hatches on top of the transformer found during maintenance. A temporary fix was applied.	Manual
Sept. 7 – 10, 2021	ASM T1	Outage	Restored	Power transformer and circuit switcher equipment maintenance.	Manual
May 23-26, 2023	ASM T1	Outage	Restored	LTC contacts. Internal inspection and assessment. Oil replaced. Report pending.	Manual
May 29- June 2, 2023	ASM T2	Outage	Restored	LTC contacts. Internal inspection and assessment. Oil replaced. Report pending.	Manual

1.2 Please provide the assessment reports for the ASM T1 and T2 LTC contacts.

Response:

Please refer to Attachment 1.2 for the 2023 ASM T1 and T2 Transformer LTC Condition Assessment Report.

2. Reference: Exhibit B-4, BCUC IR 3.5

"Even if it were possible to calculate a [Probability of Failure (PoF)] accurately, an acceptable PoF would need to be determined for each individual asset. A PoF of 2% may be acceptable for a transformer located in a substation with no immediate neighbors and supplying non-critical load but would probably not be acceptable for a transformer located in a densely populated area supplying the central business district of a major city. Other factors to consider would be the location within the system, the redundancy in the system, the availability of a spare transformer or spare components, etc."

2.1 Please identify all other transformers in FBC's transmission system with a Total Risk of Failure greater than 2 percent.

Response:

Please refer to the response to CEC IR1 11.4.

2.2 Please confirm the 2% PoF in the CEATI reference is an example only, and not a "recommendation". If not confirmed, please cite additional references for the use of 2% PoF as the recommended acceptable threshold for the ASM transformers.

Response:

The 2 percent PoF is neither an example nor a recommendation; it is a consideration that FBC has applied to transmission assets which are heavily loaded and supply multiple customers and communities. The CEATI 30/113 Report concludes that risk tolerance "depends on the individual organization and the consequence of failure".

Hitachi indicated that they are part of the CIGRE Working Group A2.37, which is dedicated to transformer reliability. Hitachi indicated in the condition assessment report that ASM T1 and T2 require intervention due to a risk of failure higher than 2 percent. FBC found this recommendation aligned with the CEATI 30/113 Report.

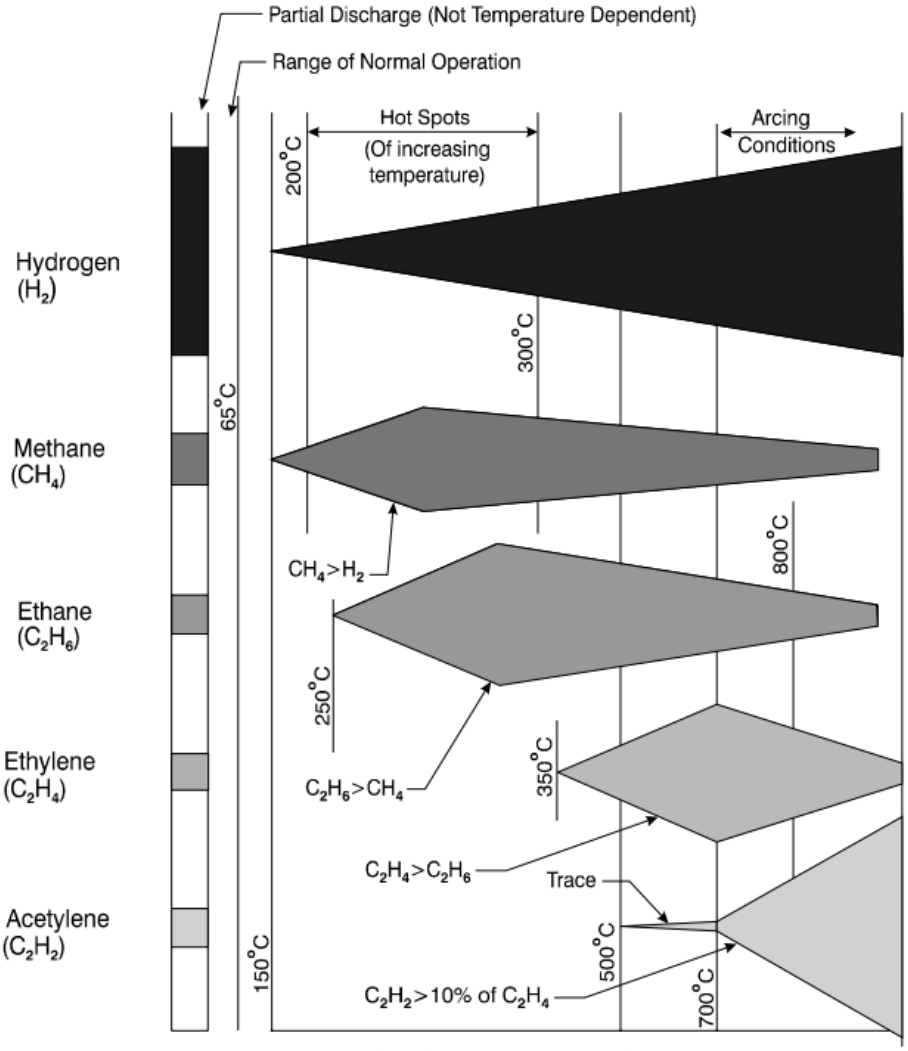
3. Reference: Exhibit B-4, BCUC IR 3.6.1

"It also portrays violent arcing during voltage adjustment and a fast decrease, year over year, in the LTCs' condition."

3.1 Arcing is an expected phenomenon for on-load tap changers. Please describe whether the "violent arcing" in the reference is beyond what is normally expected in on-load tap changer operation and provide the data that led to that conclusion.

Response:

Certain fault gases are produced more frequently in transformer oil as fault temperature increases. Please refer to the figure below from the US Bureau of Reclamation brochure "FIST 3-30 Transformer Maintenance" which indicates that acetylene is mainly produced during arcing.



To define "violent arcing", a reference is needed. Please see below the Dissolved Gas Analyses signature of:

- Duck Lake Station (DUC) T2 - ABB type UZ LTC
- ASM T2 - GE type LR-83 LTC

As per Table 1 below and FBC's inspection records, the amount of fault gases generated for 1,249 operations by the ASM T2 LTC is consistently higher than the amount of fault gases generated by the DUC T2 LTC for 2,074 operations.

The conclusion is that the GE type LR-83 LTC is arcing longer and more intensely (violent) than the ABB type UZ LTC, which currently is one of the commonly used oil arcing tap changers for the power transformers in North America.

Table 1: Arcing Pattern Comparison

LTC	Sample Date	Acetylene (ppm)	LTC	Sample Date	Acetylene (ppm)
ASM T2 LR83	4/23/2019	5,185	DUC T3 ABB UZ	5/21/2019	2,073
	4/23/2020	4,479		6/18/2020	2,105
	4/23/2021	4,867		7/28/2021	2,156
	4/1/2022	5,757		4/1/2022	2,364

3.2 Please provide the scale for the y-axis in the dissolved gas content graphs provided in the referenced response.

Response:

The y-axis represents the fault gases, dissolved in insulating oil, in milligrams per kilogram unit.

4. Reference: Exhibit B-4, BCUC IR 7.3

"The Environmental & Archeological Category was assigned a higher weighting for the ASM Project at 23 percent. This weighting has been broken down into three criteria in order to separately weight and assess the ecological and archaeological impacts of the ASM Project as well as the impact on air quality and GHG reductions. The higher weighting assigned to this category for the ASM Project is in consideration of environmental impacts and the geographical location of the Project area."

4.1 Given the location of the ASM Terminal in the midst of a heavily industrialized and modified environment, please describe the unique environmental impacts which led FBC to weight the Environmental & Archeological category for this Project so much greater than the KBTA Project.

Response:

The environmental assessment for the KBTA project included a review of the City of Kelowna's Natural Environment Development Permit and the Hazardous Condition Development Permit areas. The maps and the review confirmed that the KBTA facility is located outside of both of these environmentally sensitive areas. In contrast, the environmental assessment for the ASM Project included a desktop review of the proposed Project area which includes a steep and heavily wooded ravine.

5. Reference: Exhibit B-4, BCUC IR 9.1

"This class of transformers would require a spare to satisfy the spare equipment strategy (TPL- 001-4 Requirement 2.1.5)."

5.1 Please confirm that the referenced Mandatory Reliability Standard does not require FBC to have a spare transformer, but rather only requires that "the impact of this possible unavailability on System performance shall be studied".

Response:

The transformers proposed for the Project are not part of the Bulk Electric System (BES) since their low voltage rating is 63 kV (less than 100 kV); therefore, the Mandatory Reliability Standards do not apply. A 230/161 kV transformer option would have been part of the BES and a spare transformer could be required if studies confirmed there was an impact on system performance; however, the 230/161 kV transformer option was rejected for the reasons provided in the response to BCUC IR1 9.1.

6. Reference: Exhibit B-4, ICG IR 3.4

6.1 Please provide the monthly energy used by dedicated EV charging stations in the FBC service territory from 2021 to present.

Response:

The following table represents the aggregated monthly energy consumption in megawatt-hours (MWh) for FBC's EV charging stations as well as for sites which third-parties provide EV charging stations, as identified by PlugShare, operating in the FBC service territory from 2021 to present.

Year	Month	Energy (MWh)
2021	Jan	71.66
2021	Feb	76.58
2021	Mar	72.30
2021	Apr	70.35
2021	May	65.50
2021	Jun	114.99
2021	Jul	190.68
2021	Aug	149.00
2021	Sep	125.97
2021	Oct	118.50
2021	Nov	105.92
2021	Dec	114.78
2022	Jan	109.84
2022	Feb	111.74
2022	Mar	131.98
2022	Apr	141.85
2022	May	168.82
2022	Jun	192.95
2022	Jul	293.91
2022	Aug	269.43
2022	Sep	203.82
2022	Oct	177.35
2022	Nov	146.98
2022	Dec	153.82
2023	Jan	155.69
2023	Feb	155.34
2023	Mar	168.66
2023	Apr	167.86
2023	May	208.17

Year	Month	Energy (MWh)
2023	Jun	234.10
2023	Jul	367.26
	TOTAL	4,835.80

1

7. Reference: Exhibit B-4, ICG IR 5.3

7.1 Did FBC investigate the feasibility of a 161 kV underground cable between ASM and WTS, and if not, why not? What is the estimated cost of a 1 kilometer section of 161 kV underground cable?

Response:

FBC did not investigate the feasibility of a 161 kV underground transmission option for a number of reasons, including the following:

- The terrain and routing are not well suited to this type of option. The gulley crossing and numerous CPR crossings make it a very challenging and impractical routing option. The routing along Bingay Road would increase length (hence costs), and would also mean digging up and repaving numerous roads and excavating rock. The routing would also conflict with other underground facilities, with very limited space to put an underground circuit, and would require numerous road closures, among other challenges.
- The underground option would significantly increase project and design risks, costs, and outage response times, as well as higher life cycle cost because of the shorter design life of underground cable compared to an overhead conductor.
- FBC does not have other 161 kV underground facilities installed anywhere that it could use for emergency spares, stock or supplies; therefore, any potential failures would result in long outages.

FBC estimates the cost for this particular section of underground transmission would be in excess of $5 million per kilometer, plus there would be additional termination and substation costs.

7.2 FBC states Alternative 6 would require clearing of heavily forested gulley. Has FBC investigated historical industrial disturbance of the heavily forested gulley or performed any assessment of the ecosystems therein?

Response:

FBC did not investigate historical industrial disturbances of the heavily forested gulley or perform any assessment of the ecosystem.

Although the impacts of the brushing and clearing related to Alternative 6 were considered in the pre-screening, these were not the primary drivers for the rejection of this alternative. Nonetheless, FBC's desktop review identified a higher potential for unforeseen impacts inherent in this alternative due to past industrial disturbance. Further, the gulley has generally had re-

1 establishment of vegetation, which contributes to slope stability and the return of habitat, both of
2 which would be impacted by vegetation removal.

3

Attachment 1.2

LTC CONDITION ASSESSMENT REPORT
ASM T1 and T2 TRANSFORMER

Rev. 2

By FortisBC EMPR

Permit to practice
FortisBC Inc.
1001962

Prepared by	Checked by	Date	Rev #
Paul Gheorghe P.Eng	Shelby Ravestein P.Eng	June 5, 2023	0.0
Paul Gheorghe P.Eng	Jonathan Reimer P.Eng	July 17, 2023	1
Paul Gheorghe P.Eng	Jonathan Reimer P.Eng	Aug 8, 2023	2

TABLE OF CONTENTS

1.0 INTRODUCTION

As identified in the 2022 Hitachi "3767685 - Fortis BC ASM Substation Transformer Condition Assessment Report Rev 1", FBC has performed an additional maintenance cycle in June 2023 and a reassessment of ASM T1 and T2 On-Load Tap Changer (LTC) condition.

The purpose of this assessment is to identify the suitability of ASM T1 and T2 LTC to continue normal operation and review potential mitigations, if possible, to reduce the risk of operating these assets until a planned replacement is approved.

As per nameplate, both ASM T1 and T2 have the LTCs as a part of the HV winding and under normal conditions operate as step-up units.

As per Annex 1, the LTCs used in ASM T1 and T2, the LR83, has a recommended arcing contacts replacement interval of 60,000 operations. On May 30, 2023, the ASM T2 counter has recorded 394,575 operations while it is assumed ASM T1 has operated **3**98,183 times (ASM T1 has a 5 digit only counter). Archived documentation does not have any records that ASM T1 and T2 LTC refurbishments were completed since 2006 (the year when CASCADE CMMS was introduced). Currently, both LTCs are well beyond normal life expectancy for GE LR83 tap changers (300,000 operations).

1.1 Background

The purpose of a load tap changer is to regulate the output voltage of a transformer. This is done by altering the number of turns in one winding, changing the turns ratio of the transformer. Since it contains moveable parts, it is one of the most complex and, at the same time, one of the essential components of the transformer.

The LTC is one of the main contributors to the failure rates of high voltage power transformers. As per SD Meyers (1), 40% of the transformer failures are caused by LTCs. Therefore, it is critical to ensure that service requirements of LTCs are observed to maintain the health of the transformer.

(1) https://www.sdmyers.com/transformer-services/maintenance/field-service/load-tap-changer/

2.0 NAMEPLATE

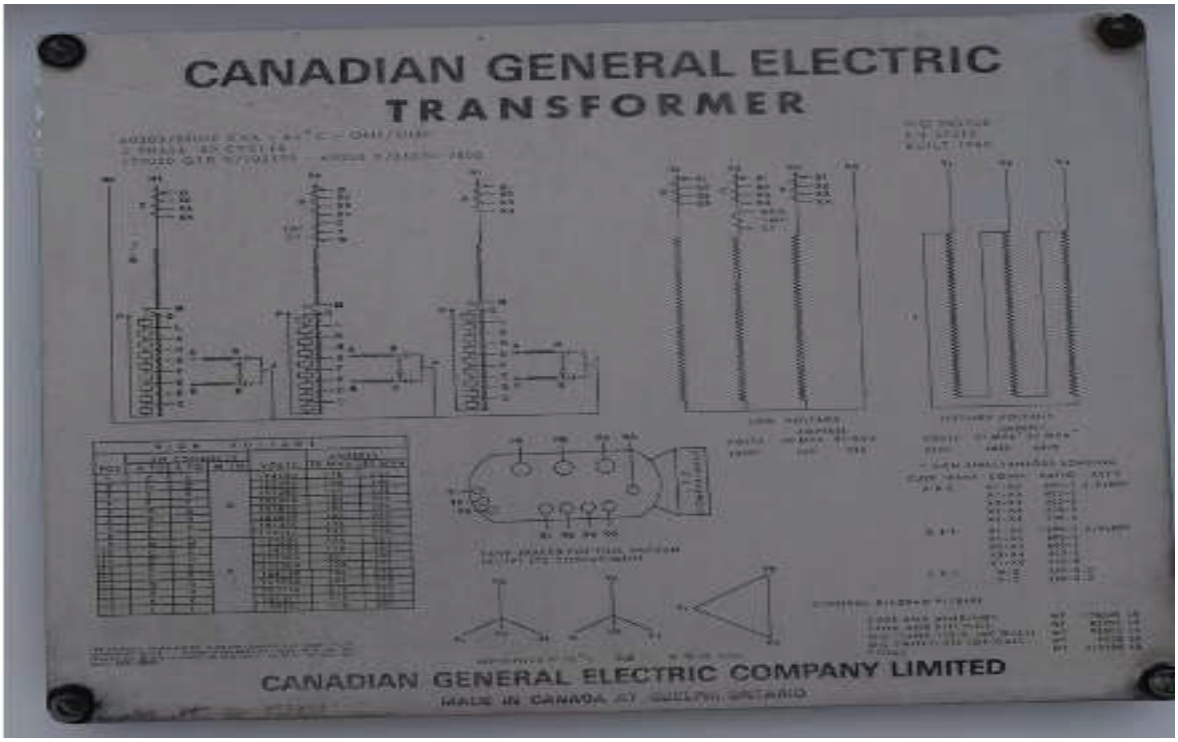


Figure 1 - ASM T1 Nameplate

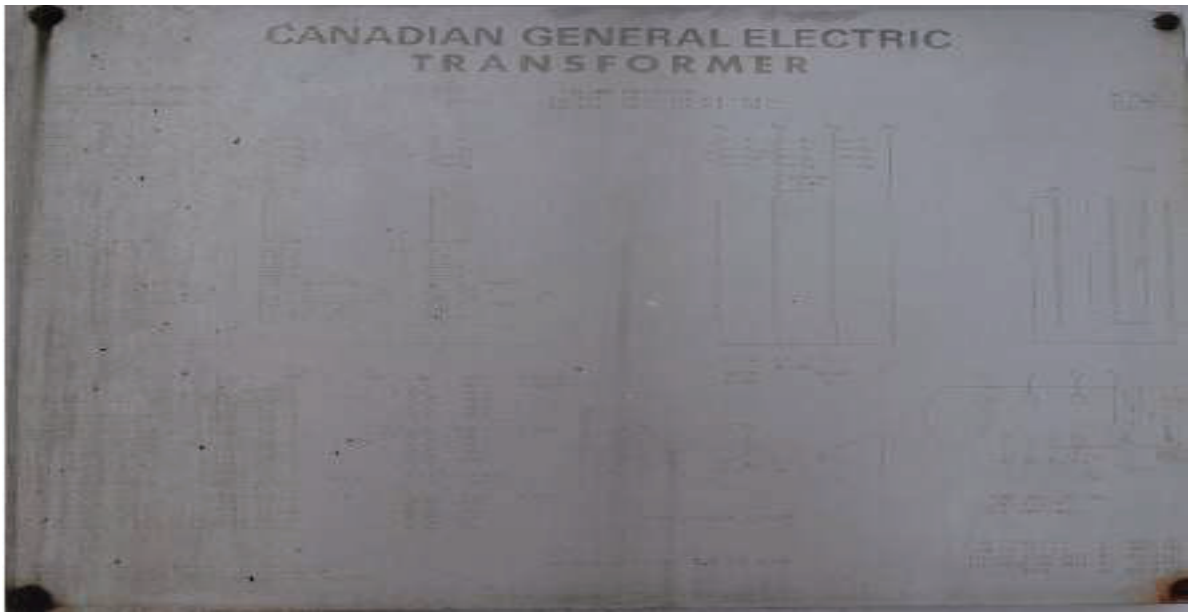


Figure 2 - ASM T2 Nameplate

3.0 LTC ASSESSMENT

To determine asset's condition, the followings inspections were performed:

Table 1 - ASM T1 Condition Assessment

#	Assessed Component	Findings	Corrective Actions
1	Liquid Insulation Condition	Oil filtration pump was found not working. The insulating oil was heavily contaminated with carbon (see Figure 3).	The LTC tank was drained and refilled with new oil. The tank and components were properly cleaned. Oil filtration is currently working.
2	Solid Insulation Condition	Ceramic pass-through bushings were heavily contaminated with carbon deposits. The LTC insulating board had no cracks and there were no leaks.	Clean up was performed.
3	Mechanical Motion (1)	The following were inspected and found in acceptable condition: • Geneva gear and Geneva drive • Scroll cam • Levers • Assembly boards	NA
	Mechanical Motion (2)	The LTC was operated without oil. It seemed to operate properly but noisy-violent. Dynamic Braking System could not be inspected (protective shroud could not be removed). No bouncing was observed but the mechanism did not stabilize immediately after the tap sequence was completed. This appears to be normal for unit with no dashpots.	NA
4	Synchronization	The three LTC heads seem to operate in perfect synchronism and the sequence of operation was as expected.	NA
5	Critical Measurements	Even if apparently, all seems to be ok, due to the age of the compression springs, it is expected that the contact's pressure might be outside the normal range.	User manual is not available. Measurements and adjustments could not be performed. Manually actuating each contact was the only option.
6	Tap and Stud Contacts	Based on visual inspection only, contacts seem to be in good shape and there is not need for immediate replacement. Some moderate contact coking was observed.	Due to the lack of spare compression springs, dismantling was not attempted. Slide contacts were cleaned by operating the LTC.
7	Contact Carrier, Heads, Collector Rings and Push Rods	Based on visual inspection only, the contact carrier, heads, collector rings, and push rods seem to be in good shape. There were no signs of flash over or across. There is no need for contact replacement.	NA

8	Reversing Switch and Contacts	The reversing switch seemed to operate properly. There were signs of pass-through operation (scratches). No coking was observed. There is no need for contact replacement.	NA
9	Diverter Contacts (1)	Diverter's main mobile and fixed contacts did not show signs of wear and did not need to be replaced.	*Review action plan after completing EIR-E-2023-09 "GLE T2 LR 83 LTC failure"*
	Diverter Contacts (2)	Diverter's arcing contacts were found heavily pitted. In-service contacts are reverse engineered after market parts and do not pair off properly (angled, not flat). This explains DGA results.	Only cleaning was completed. In 2-3 years, all arcing contacts should be replaced.
10	Auxiliary Contacts	The auxiliary contacts were visually inspected and are in ok condition.	Contacts were cleaned with spray on contact cleaner.
11	Motor Drive	Measured inrush and operating currents did not indicate any problems.	LTC motor is not making use of starting capacitors. The centrifugal switches could not be assessed.
12	Tap Counter	The tap counter seemed to operate properly.	NA
13	Dynamic Performance	Not performed. Outage window was too short to complete any electrical tests.	To be rescheduled for 2024.

Table 2 - ASM T2 Condition Assessment

#	Assessed Component	Findings	Corrective Actions
1	Liquid Insulation Condition	Oil filtration pump was working.	The LTC tank was drained and refilled with new oil. The tank and components were properly cleaned.
2	Solid Insulation Condition	Ceramic pass-through bushings were mildly contaminated with carbon deposits. The LTC insulating board had no cracks. The ceramic pass-through bushings were in acceptable condition. There was a small leak from the main tank. Signs of flashing across were recorded on insulating push rods.	Clean up was performed. Due to the constructive type of seal and the lack of access, a proper leak mitigation could not be completed.
3	Mechanical Motion (1)	The following were inspected and found in acceptable condition: • Geneva gear and Geneva drive • Scroll cam • Levers • Assembly boards	NA
	Mechanical Motion (2)	The LTC was operated without oil. It seemed to operate properly but noisy-violent. Dynamic Braking System could not be inspected (protective shroud could not be removed). No bouncing was observed but the mechanism did not stabilize immediately after the tap sequence was completed. This appears to be normal for units with no dashpots.	NA
4	Synchronization	The three LTC heads seem to operate in perfect synchronism and the sequence of operation was as expected. A misalignment was observed in the operating gear and that might be caused by operating gear wear (see Figure 6).	Investigate further.
5	Critical Measurements	Due to the age of the compression springs, a jig saw pattern was recorded during electric resistance measurement (see Figure 7). This is a sign of non-uniform/reduced contact pressure.	User manual is not available. Measurements and adjustments could not be performed. Manually actuating each contact was the only option.
6	Tap and Stud Contacts	Based on visual inspection only, contacts seem to be in good shape and there is not need for immediate replacement. Some moderate contact coking was observed (see Figure 4).	Due to the lack of spare compression springs, dismantling was not attempted. Slide contacts were cleaned by operating the LTC.
7	Contact Carrier, Heads, Collector	Based on visual inspection only, the contact carrier, heads, collector rings, and push rods	NA

	Rings and Push Rods	seem to be in good shape. There were no signs of flash over or across. There is no need for contact replacement.	
8	Reversing Switch and Contacts	The reversing switch seemed to operate properly. There were signs of pass-through operation (scratches). No coking was observed. There is no need for contact replacement.	NA
9	Diverter Contacts (1)	Diverter's main mobile and fixed contacts did not show signs of wear and did not need to be replaced.	*Review action plan after completing EIR-E-2023-09 "GLE T2 LR 83 LTC failure"*
	Diverter Contacts (2)	Diverter's arcing contacts were found heavily pitted. In-service contacts are reverse engineered after market parts and do not pair off properly (angled, not flat). This explains DGA results and the assumption of violent-uncontrolled arcing (see Figure 5)	Only cleaning was completed. In 2-3 years, all arcing contacts should be replaced.
10	Auxiliary Contacts	The auxiliary contacts were visually inspected and are in ok condition.	Contacts were cleaned with spray on contact cleaner.
11	Motor Drive	Measured inrush and operating currents did not indicate any problems.	LTC motor is not making use of starting capacitors. The centrifugal switches could not be assessed.
12	Tap Counter	The tap counter seemed to operate properly.	NA
13	Dynamic Performance	Some anomalies have been recorded. See Figure 7 indicating fluctuating tap to tap resistance.	Reschedule testing for 2024.

4.0 SPARE PARTS

The only spare parts available are some reverse engineered/aftermarket arcing contacts. They are stored onsite.

As stated in Section 3, the inspection found that some of the reverse engineered components have manufacturing tolerances, which do not allow for proper surface mating. This makes them a valuable emergency restoration spare part, but they cannot represent a permanent refurbishment solution.

No other spare parts, such as auxiliary contacts, pressure springs, push rods, etc., are available. In case one of these components fails, if the transformer itself survives, the LTC operation will need to be locked out.

5.0 RISKS AND MITIGATION

Table 3 Modes of Failure and Mitigation Actions

#	Modes of failure	Risk	Mitigation	Remanent Risk (2)
1	Liquid insulation failure	Internal uncontrolled flash	Replace LTC oil and ensure the oil filtration system is fully functional (completed). For ASM T2, oil leaks between the main tank and LTC could not be mitigated but the leak is small.	Low
2	Solid insulation failure	Flash Over or Flash Through	Nothing available currently due to the lack of OEM support.	Moderate
3	Mechanical breakdown	Mis- or slow operation	Nothing available currently due to the lack of OEM support.	Moderate
4	Out of synchronism operation	Out of step operation	Due to the lack of OEM support, only small adjustments can be attempted.	Moderate
5	Exceeded tolerances	Mechanical jam.	Due to the lack of OEM support, only small adjustments can be attempted.	Moderate-High
6	High contact resistance	Contact overheating, coking, and melting	When required, clean and replace arcing contacts with what is available. Internal inspection with a shorter periodicity. DGA every 3 months.	Moderate
7	Excessive arcing	Excessive arcing	Replace contacts with what is available. Ensure the oil filtration is fully functional. Perform internal inspections with a shorter periodicity. DGA every 3 months.	Very High
8	Auxiliaries' failure	Slow and inconsistent operation. LTC lockout.	If detected early, LTC operation can be locked out. However, slow operation cannot be monitored so there are no real mitigation options.	Low- Moderate

(2) Represent the likelihood the failure will lead to transformer end of life.

6.0 RECOMMENDATIONS

ASM T1 and T2 advanced age and the accumulated LTC number of operations indicate that these units have been well taken care of, however according to industry classification of the detection failures, LTC failure is one of the most common failures that occurs in a transformer.

Due to the lack of support from the OEM and the substandard quality of the available spare parts, unforeseen transformer failure is likely. Locking out ASM T1 and T2 LTCs will only strain other transformers in the system.

Even if imminent failure is not currently a concern, due to the extremely long lead time for new transformers *(delivery has currently increased to 170 weeks from PO)*, it is recommended to start the replacement planning process asap.

As an interim, to insure ASM T1 and T2 can support the network as required, additional maintenance and close supervision, as specified in the mitigation section, will be required.

Due to age and condition, overloading ASM T1 and T2 comes with an increased risk of LTC failure. *Overloading is not recommended.*

7.0 PICTURES and ANNEXES

Figure 3 ASM T1 High Carbon Contamination

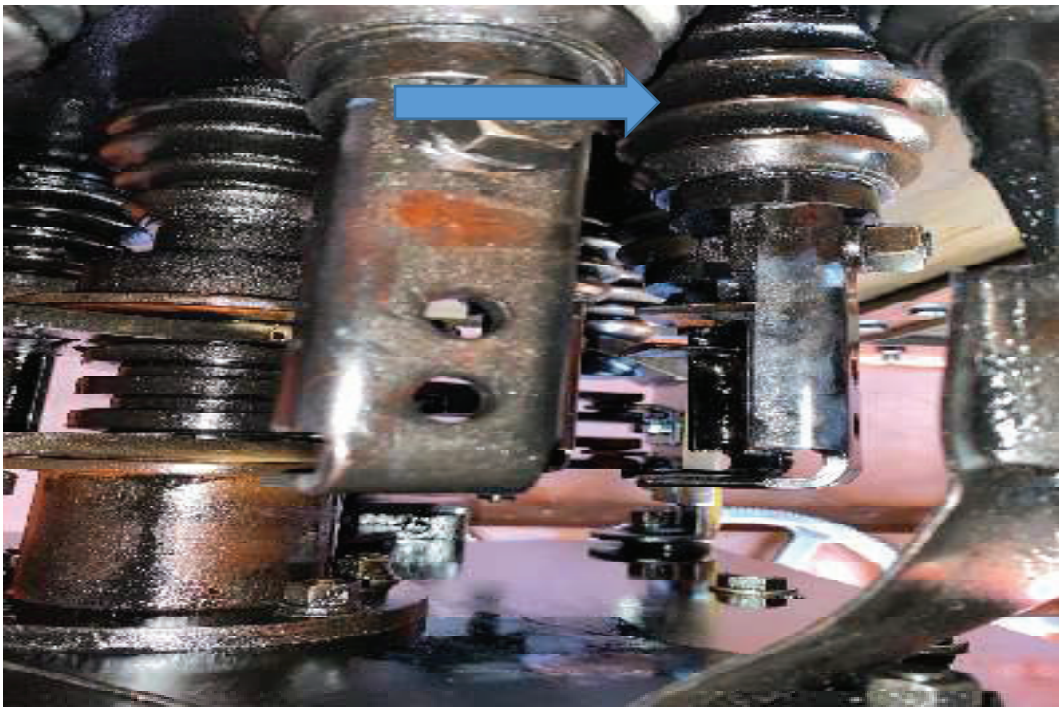


Figure 4 ASM T2 Coking of Selector Ring and Carbon Contamination

Figure 5 ASM T2 Signs of uncontrolled arcing

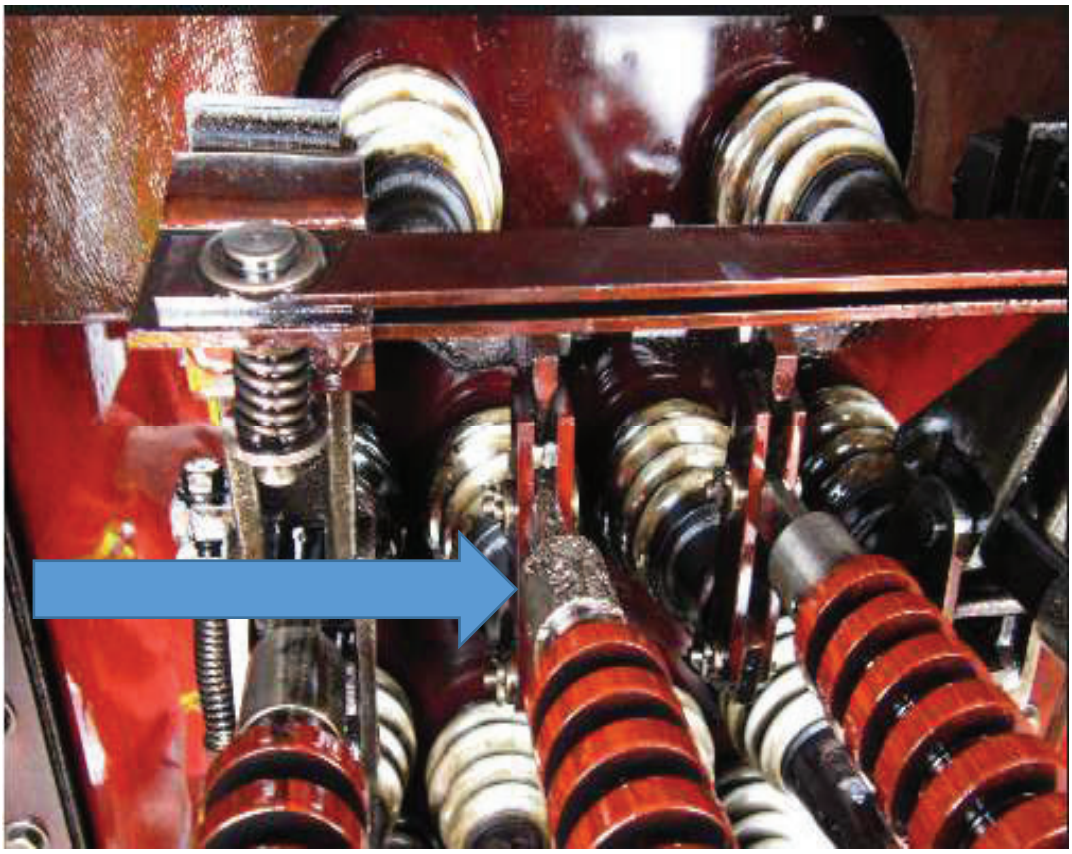
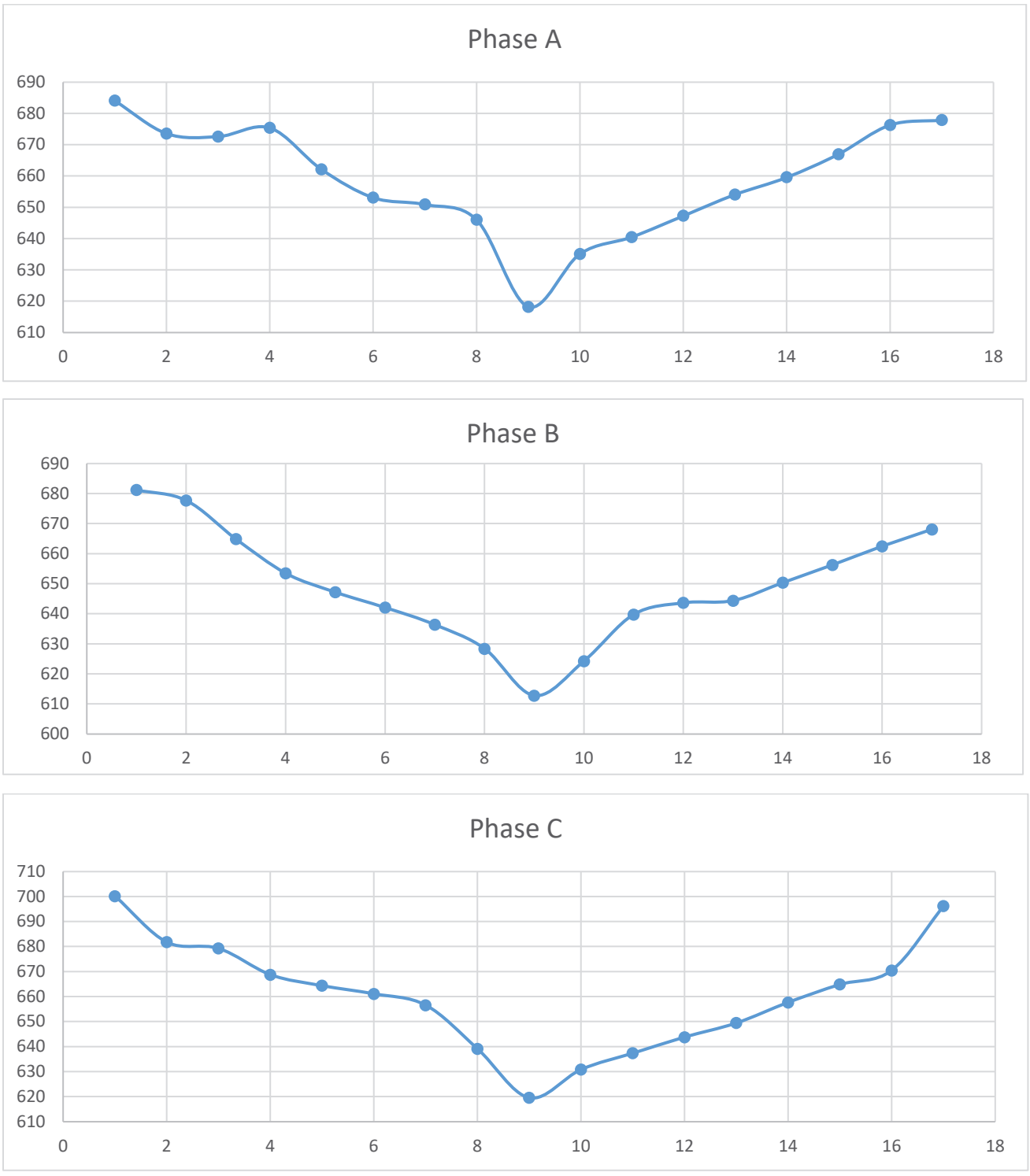


Figure 6 ASM T2 Misalignment of the gear mechanism

Figure 7 ASM T2 Winding Resistance (LTC side)



X Axis resistance in micro-ohms. Y Axes LTC tap number.