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Health Index Assessment of Power Transformer

Presented By:

- **DJELLOULI Fawzi**
- **DJELLOULI Abdelkadir**

Supervisor:

Dr.BOUCHAHDANE Mohammed

Co-supervisor:

Ing.BENLAHNECH Saad Eddine

Ing.BOUGUERA Makdad

Registration Number:……../2020

Dedication

In the name of Allah the most Merciful and Beneficent.

This thesis is dedicated to my mother. She was constant source of inspiration to my life. Although she is not here to give me strength and support I always feel her presence that used to urge me to strive to achieve my goals in life.

To My great father, who were real supports, without forgetting my beloved brothers, my sister and all my family.

I wish to express my sincere appreciation to DJELLOULI Fawzi, KISSOUM Malik and all my friends who encourage and support me from in or out the institute.

To all the staff of IGEE for the great journey of five years.

THANK you ALL

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Abstract

A health index is a tool that processes service and condition data into a score which describes the overall health of an asset. The motivation behind this is to objectively and confidently assess the condition of power transformers so that reinvestment and maintenance decisions might be justified. This way, the technical lifetime of healthy assets might be safely increased, while risky assets can be identified and taken care of before they fail. Health indexing is particularly useful for evaluation of large transformer fleets, since it makes it easy to identify the assets most in need of additional attention. An important prerequisite for a health index to be useful is, however, that the availability of data is considered in the model design. A health index intended for use in Algeria will thus have to be customized to the data availability faced by most Algerian utilities and transformer users.

In order to identify which assessment methods that are suited for use in an Algerian health index, four existing health index models (DNV KEMA, Hydro-Québec, Kinetrics, EDF method) have been reviewed. Based on these reviews and the general data collection practices of Algerian utilities, a health index model has been proposed and implemented in a program based on python.

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Abbreviations

TSO	Transmission system operators
DSO	Distribution system operators
FMEA	Failure Modes and Effects Analysis
LV	Low Voltage
OLTC	On Load Tap Changer
DETC	De-Energize Tap C hanger
IEEE	Institute of Electrical and Electronics Engineers
CIGRE	Conseil international des grands réseaux électriques
EPRI	Electric Power Research Institute
USA	United States of America
FRA	Frequency response analysis
OFAF	Oil Force Air Force
EFP	Earth fault protection
SCBT/S	Short circuit between turns/stands of windings
SCTG	Short-circuit to ground
SCL	Short- circuit between laminations
UC	Ungrounded core
MG	Multiple grounding
OC & CR	Open circuit and contact resistance
CT	Conductor tilting
CB	Conductor bending
HV	High voltage
WBM	Winding bulk movement
CSF	Clamping system failure
LD	Lead deformation
CTF	Compression hoop tension failure
IR	Insulation resistance
DC	Direct current
FRSL	Frequency response of stray losses
TTR	Transformer turn ratio

General Introduction

General introduction

A modern electric power system is a very large and complex network consists of generators, transformers, transmission lines, distribution lines, and other devices. The purpose of the electric power system is to produce, supply, transmit and use electric power. This power system is also known as the grid and can be broadly divided into the generators that supply the power. The transmission system that carries the power from the generating centre to the load centre, and the distribution system that feeds the power to nearby homes and industries, such system as those shown in Figure 1. [1]

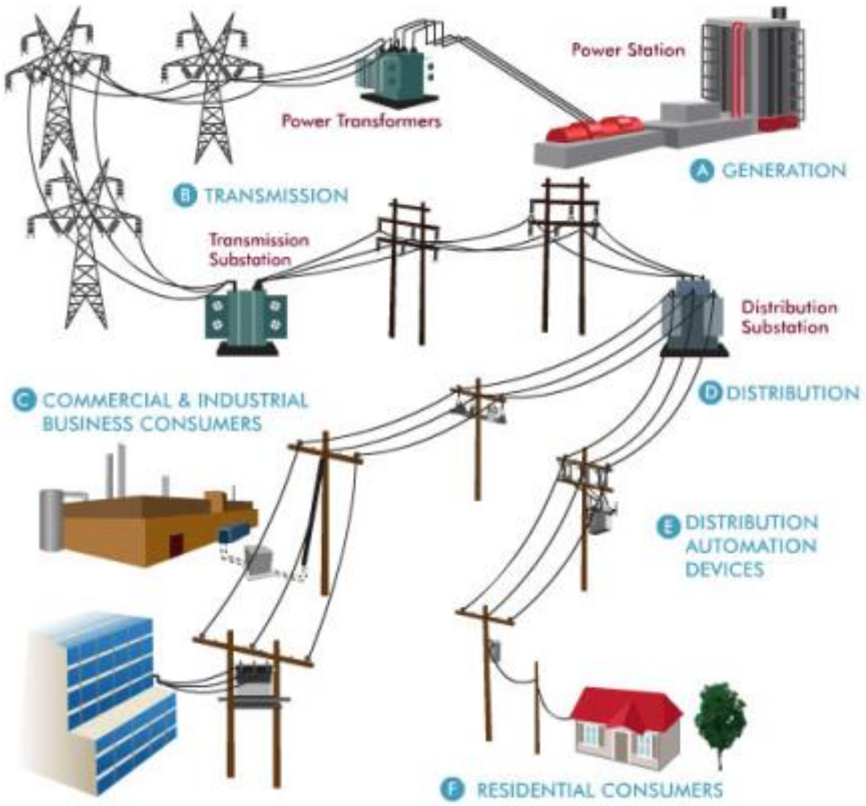

Figure 1: power generation and distribution system

The power transformer is not only one of the most important components in the power system, but also one of the most expensive in terms of reinvestment. In order to fully utilize assets, and thus postpone reinvestments, asset owners continuously seek ways to increase the lifetime of their power transformers. It is, however, important that transformers are not operated to the point where they begin to pose a threat to their environment. Unexpected transformer failures are often associated with severe consequences and substantial costs, and assets in a poor condition should therefore be identified and taken care of before a failure occurs. Appropriate measures in such cases include both maintenance and reinvestment, and a course of action is decided upon based on factors such as the asset condition and importance. However, because acquisition times for power transformers are very long, it is important that future maintenance and reinvestment is properly scheduled. For this, condition assessment is a prerequisite [3].

Power transformers are usually very reliable, with a 20-30 years design life. In practice life of a transformer can be as long as 60 years with appropriate maintenance. [2]. To ensure a safe and economically optimized operation, asset managers must find ways to direct resources to where they are needed the most. This is a comprehensive task that requires both deep knowledge about the transformer and a good overview of the fleet. In recent years the concept of health indexing has been proposed as a tool to aid such decisions. A health index allows for a quick and efficient way to evaluate and compare the overall condition of all the transformers in a fleet. [4]

CHAPTER I

Failure Modes and Statistics

1.1 Introduction

There are three main types of power transformers, namely, oil immersed, gas-insulated, and dry-type transformers with or without cast coil insulation system. This thesis based on Oil-Immersed transformers which are commonly and economically used for a wide range of voltage and power ratings for many decades from distribution to transmission levels or from MV to UHV applications. They use paper-wrapped windings immersed in mineral oil, which serves as both the insulation and cooling medium. All though these transformers are inexpensive and widely used, they are undesirable in tall buildings and densely populated urban areas because of the high fire risks that accompany the use of transformer oil. [19]

Power transformers are one of the most significant and strategically key components of the entire electric infrastructure [19]. It plays an important role by interconnecting generators, power transmission, distribution system and effect the stable operation of electric networked components. From design and operational point of view, a power transformer is divided into several components. The main part of a power transformer consists of active parts that transfer electric power from one winding to another via electric-magnetic induction. Other parts of the power transformer components include tap changer, bushing, insulation (paper, pressboard, and liquid), cooling (radiator, pump, and fan) and accessories (internal relay, temperature indication, oil level indicator, pressure relief device, over voltage protection device etc.). Figure 1.1 illustrates the main components of a typical power transformer. [20]

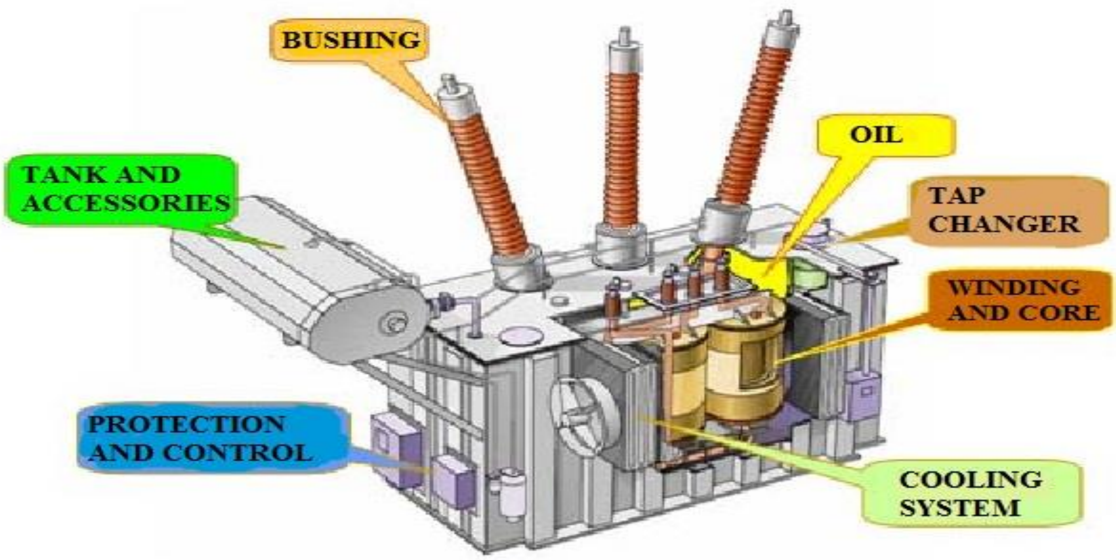

Figure 1.1: Main components of power transformer

In addition, power transformers are extensively facing numerous system abnormality issues, if the risk of failures cannot be detected and problem not fixed in time by maintenance activities, the catastrophic failure will take place, which leads to complete or partial damage of transformers and also increases the outage cost for an electric utility [22]. Hence, the focus of this research is to investigate the failures of power transformers for effective maintenance planning using new approaches and techniques.

1.2 Power transformer failure :

Power transformer failures are a great concern to electric utilities. The failure of power transformers can be defined as follows:

• Any forced outage due to transformer damage in service.

• The trouble that requires removal of the transformer for return to a repair facility, or which requires extensive field repair (e.g., excessive gas & high moisture levels).

Many international electrical study centers conduct surveys on transformer failure statistics to identify the general aspects and trends of transformer failure. [23]

1.3 Statistics on the causes of failures:

Many experts describe failure occurrences in terms of the “bathtub curve” where it is predicted that transformer failures increase through time. However, available statistics have not yet revealed a correlation between the number of failures and advancing years in service. [14]

The assessment of the state of power transformers is generally linked directly to the state of the main components which ensure the normal operation of a transformer. Failures according to statistics can identify which component is critical for the transformer state evolution.

1.3.1 IEEE:

Table 1.1 shows the significant percent deficiencies of some components of power transformers with and without a tap changer. [15]

Table 1. 1: percentage of power transformer failures according to IEEE

Condition	OLTC	DETC
Tank	6%	17.4%
Controller in charge	40%	4.6%
Winding + Core	35%	33%
Auxiliaries	5%	11%
Bushings + bounds	14%	33.3%

1.3.2 Doble and ZTZ-Service:

A failure analysis based on periodic reliability surveys was carried out by ZTZ-Service (the relevant population is about 5000 units, above 100 MVA, 110-750 kilovolts), and by Doble laboratories whose results have been partially edited. The comparison of the statistical data of ZTZ-Service and those of Doble are given in Table 1.2 below. [9]

Table 1. 2: causes of power transformer failures according to Doble and ZTZ-service

Rate% / Defective element	Doble	Service – ZTZ
bushing	35	45
chap changer	16	9
Major insulation	9	17
Aging winding (turns, winding)	16	12
Winding distortion	12	10
Core	7	7
Connections	5	-

1.3.3 CIGRE:

Another glimpse by a CIGRE A-2 working group on power transformer failures had shown that about 41% of failures were due to OLTC switches and about 19% were due to windings. Table 1.3 shows the percentage distribution of failure for transformers with OLTC.

Table 1. 3: percentage of transformer failures with tap changer according to CIGRE [15]

Defective component	CIGRE %
Tap charger	41
Winding	19
Tank and fluid	12
Accessories	11
Bushing	12
Core	5

1.3.4 EPRI:

According to EPRI (1999), failures in transformers installed in USA cover about 25% of population. It was found that the failures are fundamentally related to the crossings and the insulation of the windings.

Table 1. 4: percentage of power transformer failures according to EPRI [17]

Defective component	EPRI US %
Bushing	30
Dielectric Strength	21
Cooling and Others	12
Mechanical Failure	11
Other	5

1.4 Failure Mode

The failure of a transformer can be a devastating and costly situation. However, it is an unfortunate fact that despite even the most rigorous preventative maintenance program, failure and will occur. In order to prepare an accurate failure scenario, and develop proper recommendations to prevent a recurrence, a more in-depth analysis of the failure or a root of failures is necessary to undertake. To accomplish this, it is necessary to first understand the different modes of failure for transformers. [7]

1.4.1 Mechanical Failure Mode:

By the principle of its operation, the transformer is under constant magnetic forces that are withstood under rated conditions by the mechanical clamping, bracing and design of the transformer. Under fault conditions, the current submitted to the transformer exceeds rated values. In fact the force occurring in the transformer due to short circuit will increase the fault current that exceed mechanical withstand of the transformer leading directly to failure of power transformer [8]. The following typical scenarios of a transformer failure related to the mechanical cause are as follows:

· Deformation of the winding geometry and the core and loss of the mechanical stability.
· Loss of clamping pressure, spacers.
· Displacement of leads.

1.4.2 Electrical Failure Mode:

There are different reasons why electrically induced stresses lead to failure of the power transformers. Typical causes are due to:

· Operation of a transformer under transient or sustained over-voltage conditions.

· Exposure to lightning surges and switching surges.

· Partial discharge (corona) can be caused by poor insulation system design, by manufacturing defects, and / or by contamination of the insulation system (both the solid insulation and oil). [5]

These failure modes may be found in combination with one another or combination with other mechanical or thermal evidence or dielectric. It is important for all evidence to be evaluated together in order to develop an accurate failure scenario. [7]

1.4.3 Dielectric Failure Mode:

Dielectric mode failures involve insulation breakdown leading to flashovers between windings, phase to phase, turn to turn, the exit leads and core to ground insulation.

The major insulation is used to insulate the windings from the iron core and insulate or separate the primary winding from the secondary winding. The minor insulation on the other hand is used to insulate or separate one layer of turns to the next layer [10].

1.4.4 Chemical Failure Mode:

Chemistry failure modes are a result of corrosion and contamination with particles (cellulose fibers, iron, aluminum, copper and other particles), gas or moisture eventually leading to dielectric flashovers in the oil insulation, winding to ground insulation and minor insulation.

Water, oxygen, oil aging products (particularly acids) and conductive particles of different origin are degradative agents, which can significantly shorten transformer life under the impact of thermal stresses, electric field, electromagnetic and electrodynamics. [12]

1.4.5 Thermal Failure Mode:

The degradation of a cellulose insulation system is to be expected over time. Normal heating generated by the loading of a transformer will thermally degrade the insulation. Thermal degradation result in the loss of physical strength of the insulation that, over time, will weaken the paper to the point where it can no longer withstand the mechanical integrity imposed on it by the vibration and mechanical movement inside of a transformer [14].

However, a well-designed transformer's insulation system should be able to provide reliable service for 20 to 30 years or more (design life). The reasons for the premature failure of a transformer are generally either poor operating and maintenance practices, or defective workmanship and/or materials, insufficient withstand designs. If evidence of thermally induced problems is found, it must be considered and combined with any other evidence discovered of mechanical or electrical problems to develop a complete failure scenario [7].

1.5 Conclusion

In this chapter, we have seen a review on the statistics of failure in different standards. Then we have discussed the different type of failure mode on power transformer such as mechanical, electrical, thermal, chemical and dielectric failure mode.

CHAPTER II:

Failure Causes and Their Effects on Power Transformer

2.1 Introduction:

The next step is to identify the causes of failures and their effects. The failure effect is a measurement of how the failure influences the power transformer components. Further, it determines whether the failure will cause a complete equipment failure, a partial part of the equipment degradation or there is actually no failure impact at all to the power transformer components performances.

2.2 Determination of the failure causes and their effects on power transformer:

The identification of root causes and their effects was performed using logic tree approach:

2.2.1 Short circuit between turns/stands (SCBT/S) of windings:

There are few ways to represent the causes for winding short-circuits between turns and strands failure modes. The current in the shorted turns will be significantly higher than the normal operating current and therefore abruptly increases the winding's temperature resulting in severe damage or even the breakdown of the insulation. The short- circuit between turn faults can develop a phase-to-phase short circuit or phase- to-ground faults or get shorted from the same phase resulting in extensive damage to the winding insulation. When this failure takes place, the transformer cannot remain in service. The causes for short-circuiting between turns/strands are shown in Figure 2.1. [33]

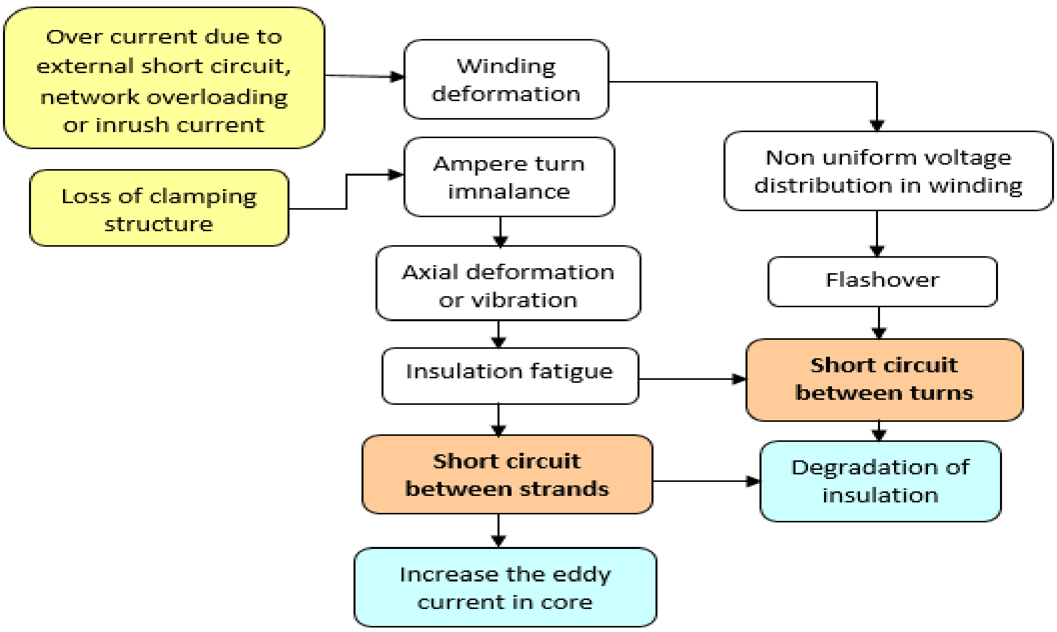

Figure 2.1: Causes and effects of short circuit between turns failure

Moreover, either winding deformation or lack of clamping creates the difference in height between windings resulting in ampere-turn imbalance [24]. Such imbalance induces axial deformations resulting in intensified vibrations that stress the insulation between strands and turns. Depending on the severity of the insulation fatigue SCBT and SCBS can occur. These failures lead to abnormal temperatures and generate aging by-products (particles, gasses). [25]

2.2.2 Short circuited core lamination (SCL):

The short- circuit between laminations (SCL) is the most typical failure caused in the core of the transformers. This normally takes place due to the damage of core lamination partly or deteriorated core lamination insulation, debris in contact with core and core bolt fails leading to core local heated. Local overheating in the core could be present due to the circulation of eddy currents. A transformer having this failure cause cannot remain in service. The effects of the local overheating initiate a degradation process of the insulation between laminations. As time goes by, the fatigue of the insulation can lead to SCL as shown in Figure 2.2. The effect of SCL creates exciting current, and increase the core losses which increases the temperature leading to gas generation, subsequently could cause the trip of the buchholz relay. [33]

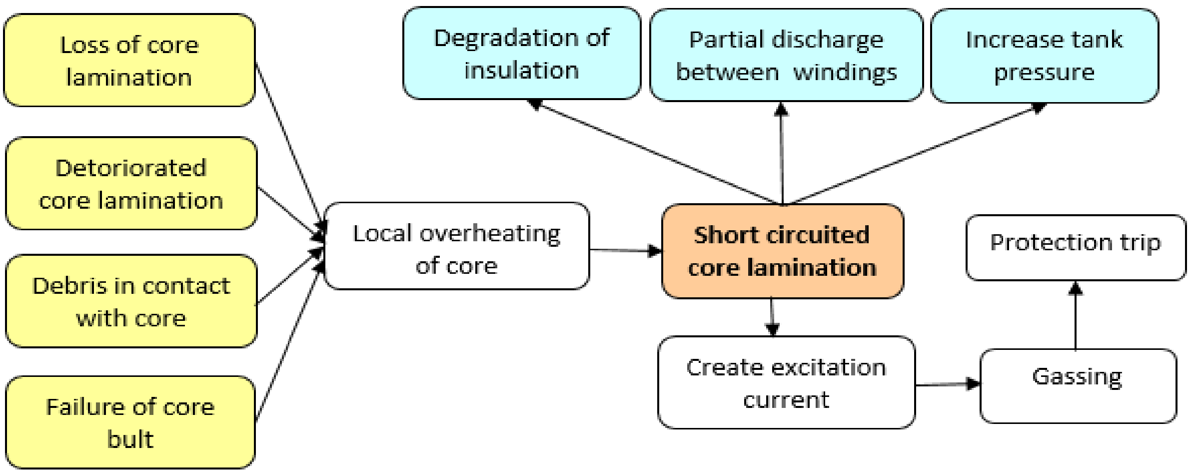

Figure 2.2: Causes and effects of short circuit between core laminations

2.2.3 Multiple Grounding (MG)

Multiple grounding (MG) is another failure caused in core, which is very difficult to detect. The MG failure is caused in two ways namely the failure of insulation between core and ground or failure of insulation between the core and the clamping system arrangement as shown in Figure 2.3. MG build up circulating current lead to local overheating within core which generate gases, predominantly Ethylene (C_2H_4), Methane (CH_4) and also a significant amount of Hydrogen (H_2) [27]. Under the occurrence of this failure cause, a transformer can remain in service, but detrimental circulating currents due to multiple core grounding will lead to a decay of the insulation between core laminations. Subsequently, result in the failure of SCL.

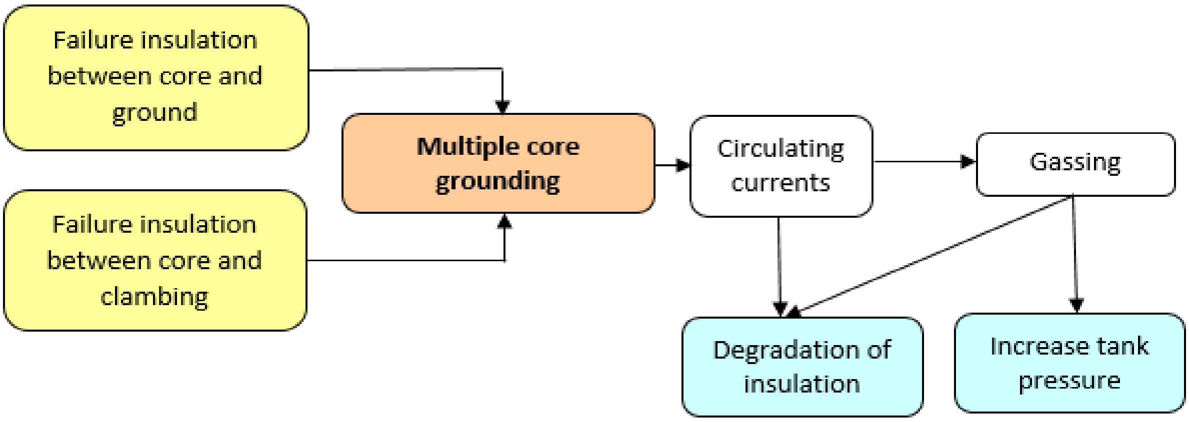

Figure 2.3: Causes and effects of ungrounded and multiple grounding core failures

2.2.4 Open Circuit and Contact Resistance (OC & CR):

The most typical thermal related failure modes are burning and melting leading to contact resistance and open circuit failures in transformers as shown in Figure 2.4. The causes for the failure mode are network overloading, poor contacts, contact deterioration and external short circuit, which increases the stress inside the transformers. This stress can overheat, causing a hotspot which will initially generate some carbon monoxide, ethylene and methane gasses. Depending on the severity of hot spot, the failure would be burning or conductor melting. Melting damages the paper insulation leading to SCTG, while burning causes an increase of CR in the current carrying system and in extreme cases, it causes an OC. [33]

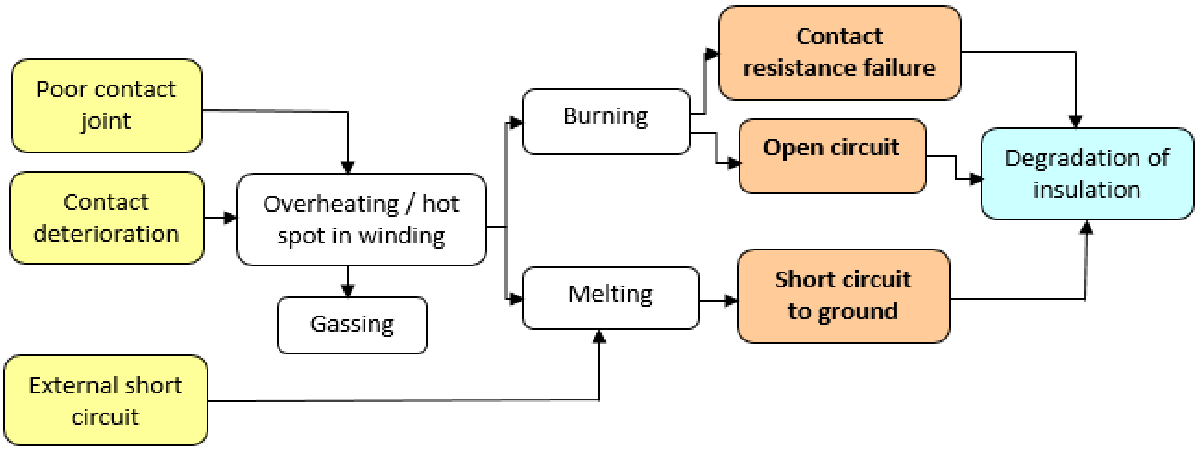

Figure 2.4: Causes and effects of thermal related failures

2.2.5 Winding bulk movement (WBM):

A bulk movement of winding is defined as a movement of individual windings with respect to other windings either upward or downward. This failure is also called axial telescoping failure [27]. The cause for WBM failure mode is shown in Figure 2.5. The typical causes for the failures are external short circuit and inrush current. High external short circuit or inrush current creates electromagnetic force. The action of electromagnetic forces (axial and radial forces) move the winding against clamping system resulting in winding moves in opposite direction relative to one another. [32]

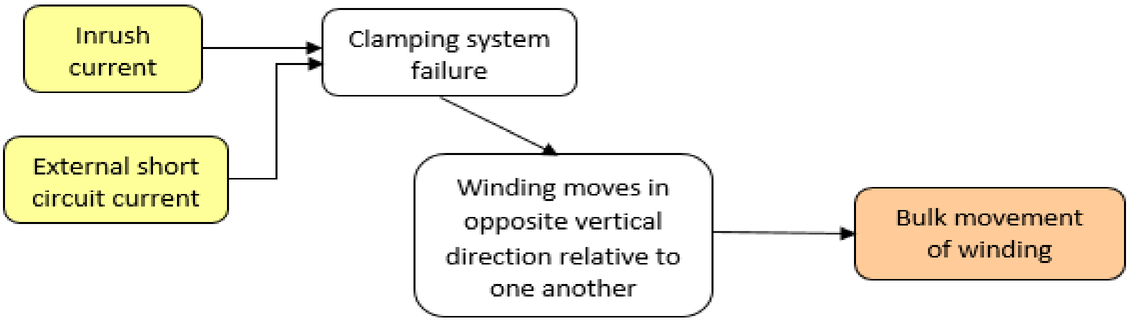

Figure 2.5: Causes and effects of bulk movement of winding failure

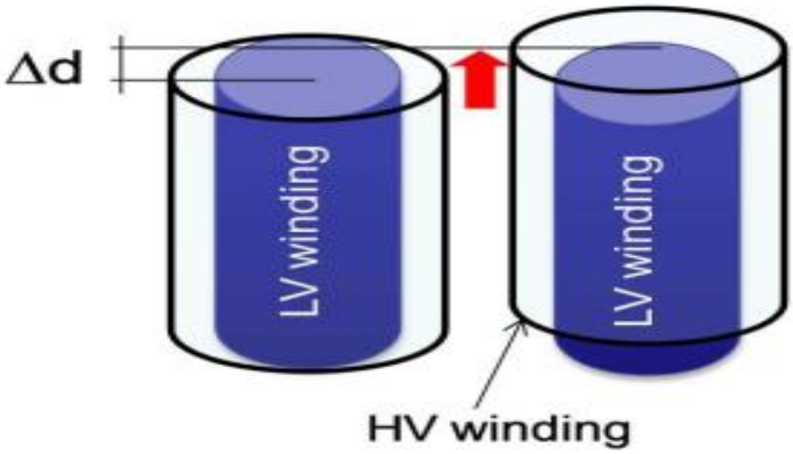

Figure 2.6: Movement of winding upwards

2.2.6 Lead deformation (LD)

The cause for the lead deformation failure mode is illustrated in Figure 2.7. During transformer operation, coils are subjected to a constant clamping force at all time. Winding internal leads gets deformed due to the action of the electromechanical forces caused by short circuit currents, a high inrush current, lightning strikes or due to shocks to a transformer during transportation. Depending on the severity of the LD either arcing or flashover is caused. The deformations reduce the electrical clearance between leads and other components, as a result, a flashover, breakdown of insulation and the comperes of core lamination due to forces are occurs . The arching generates gasses whereas flashover increases the oil pressure in the tank [33].

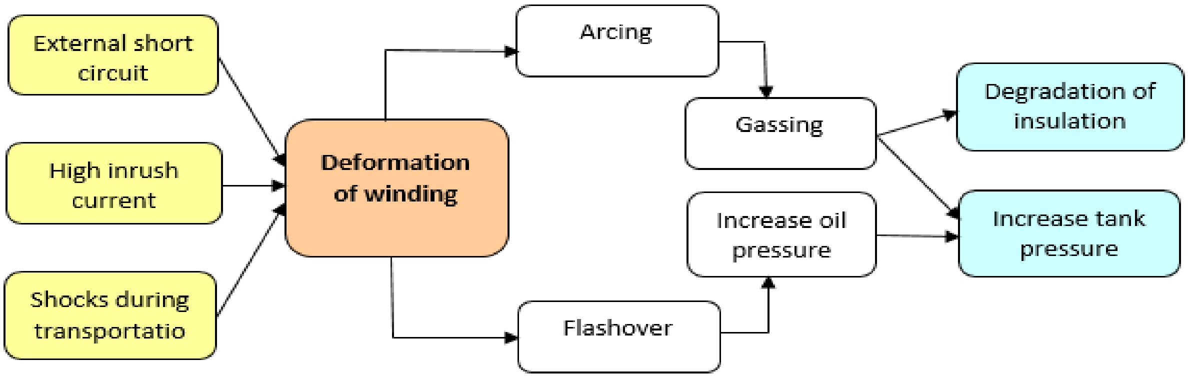

Figure 2.7: Causes and effects of lead deformation failure

2.2.7 Core deformation

The cause for the failure of core deformation is shown in Figure 2.8. Core deformation is not common in the power transformer. The action of shocks to the active part, occur either during transportation or due to earthquakes and high external short circuit impact in the axial/radial direction could lead to core deformation.

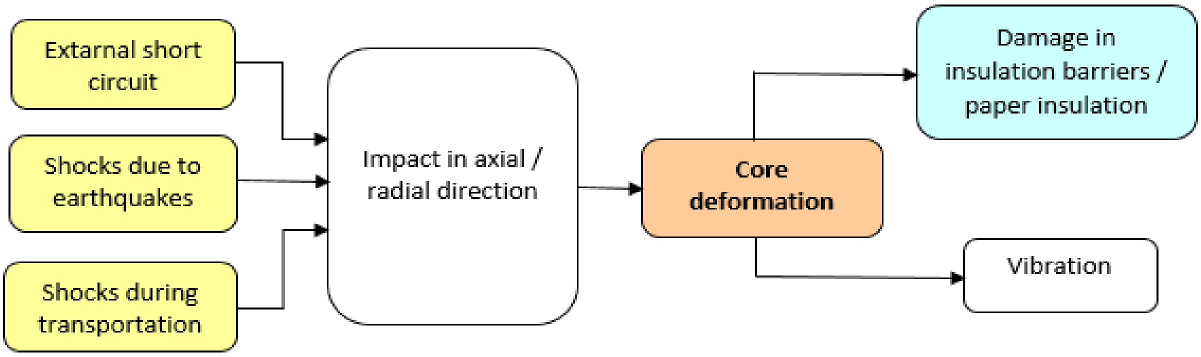

Figure 2.8: Causes and effects of core deformation failure

The operation of a transformer having a core deformation could be noisy because of excessive vibrations and could also lead to partial discharges if the deformation affects the dielectric clearances between the core and current carrying components. As a consequence of core deformations, damage in insulation barrier takes place [32].

2.2.8 Conductor bending (CB):

A typical cause for conductor bending failure mode is shown in Figure 2.9. Axial forces deflection on high voltage (HV) winding lead to CB. The conductor bending can result into damage of its insulation and a maximum stress occurs at the corners of the radial spacers.

Within high voltage winding, the axial forces are attractive, thus placing the conductors, insulation, and spacer blocks under compression. These forces exert beam stresses on the conductors, which bend the conductors between spacer blocks. The real case of CB is illustrated in Figure 2.10.

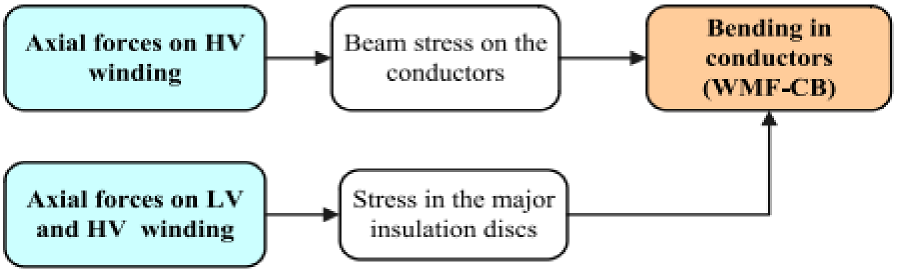

Figure 2.9: Causes and effect of conductor bending failure

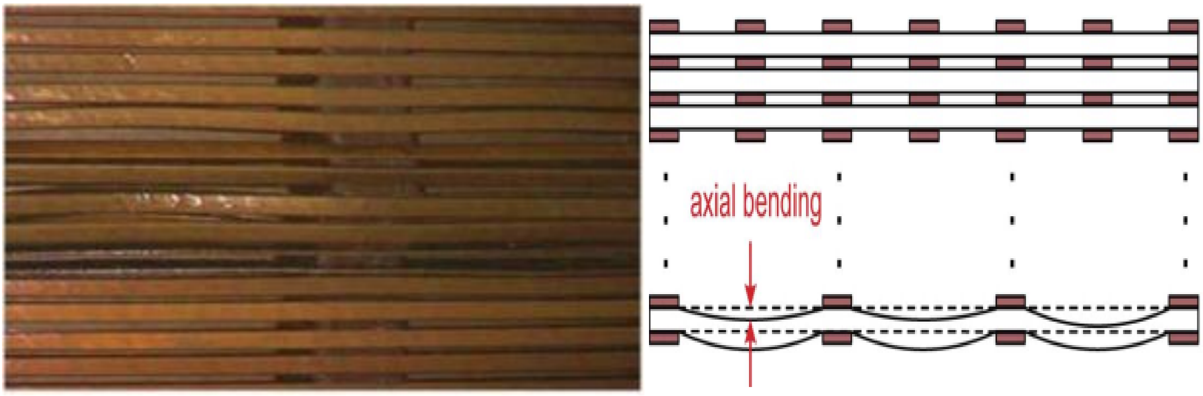

Figure 2.10: Illustration of a real case of conductor bending

2.2.9 Degradation and again of insulation:

The causes for oil-paper insulation degradation related failure modes are discussed as follow.

a) Degradation of oil insulation due to water:

The cause for transformer oil degradation is due to moisture present in the oil. Moisture slowly accumulates in transformers through the internal process of oxidation or externally via a leak. Oil oxidation process occurs when contact between humid air and oil in a free breathing conservator, via degraded gaskets and absorption when the transformer is opened for maintenance. Degrading paper cellulose (via overheat during overloading) also supplies a source of oxygen. Improper breather or conservator without rubber bag could also supply oxygen. Other factors include moisture, particles (metal, carbon, wet fibers) and copper are the catalysts for oil oxidation process in the transformer [32]. This increases the probability of a breakdown of oil is illustrated in Figure 2.11.

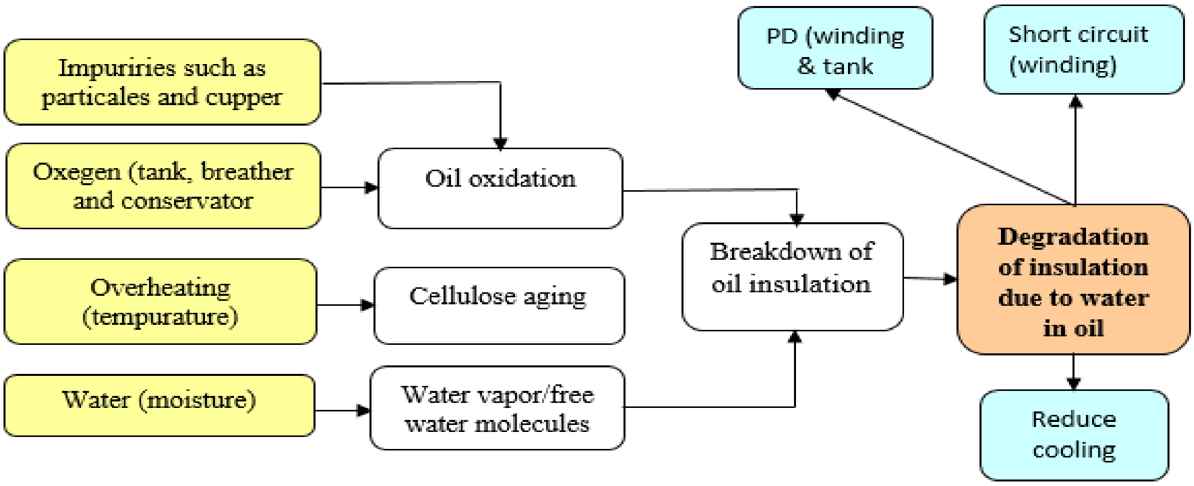

Figure 2.11: Causes and effects of oil insulation degradation failure

b) Degradation of paper insulation due to water

The cause for the degradation of paper is shown in Figure 2.12. The temperature (pyrolysis), water (hydrolysis) and oxygen (oxidation) in the transformer oil are the main causes of cellulose degradation. These three main factors influence the paper degradation.

The presence of water (Moisture) is the most important factor for paper degradation in a transformer. Moisture can enter into the paper as residual moisture in the "thick structural components" when it is not removed during the factory dry-out during assembly, ingress from the atmosphere, aging (decomposition) of cellulose and oil, and externally via a leak. Water with acids involves hydrolysis process, which breaks the cellulose polymer chain. Paper insulation is not in an acceptable condition if the number of glucose molecules in one chain is less than 200 or below DP limit [31]. Therefore, hydrolysis is a dominant cause of degradation of paper insulation.

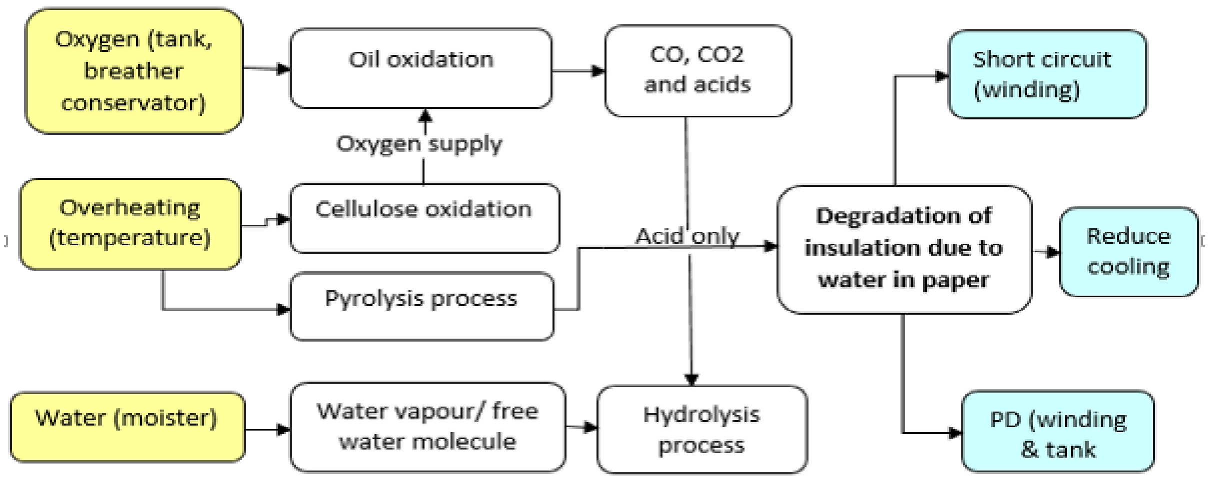

Figure 2.12: Causes and effects of paper insulation degradation failure

c) Degradation of oil and paper insulation due to temperature:

The internal temperature causes general and local overheating in transformers. The cause for degradation due to temperature for oil and paper is shown in Figure 2.13.

The causes of general overheating and local overheating were observed as a cooling deficiency, overloads, poor joints, poor circulation of oil flow, core overheating, stray flux, magnetic flux and circulating currents,…etc. As a consequence of overheating, gasses are generated that degrade the oil insulation. Moreover, a possible generation of carbon and other aging-by-products contributes to further degradation of the oil insulation. Poor joints increase the resistance of current carrying elements, which also leads to oil and local overheating. A local overheating generates gases such as CO, CO_2, and H_20. Subsequently, the sustained overload effect leading to insulation paper degradation [32].

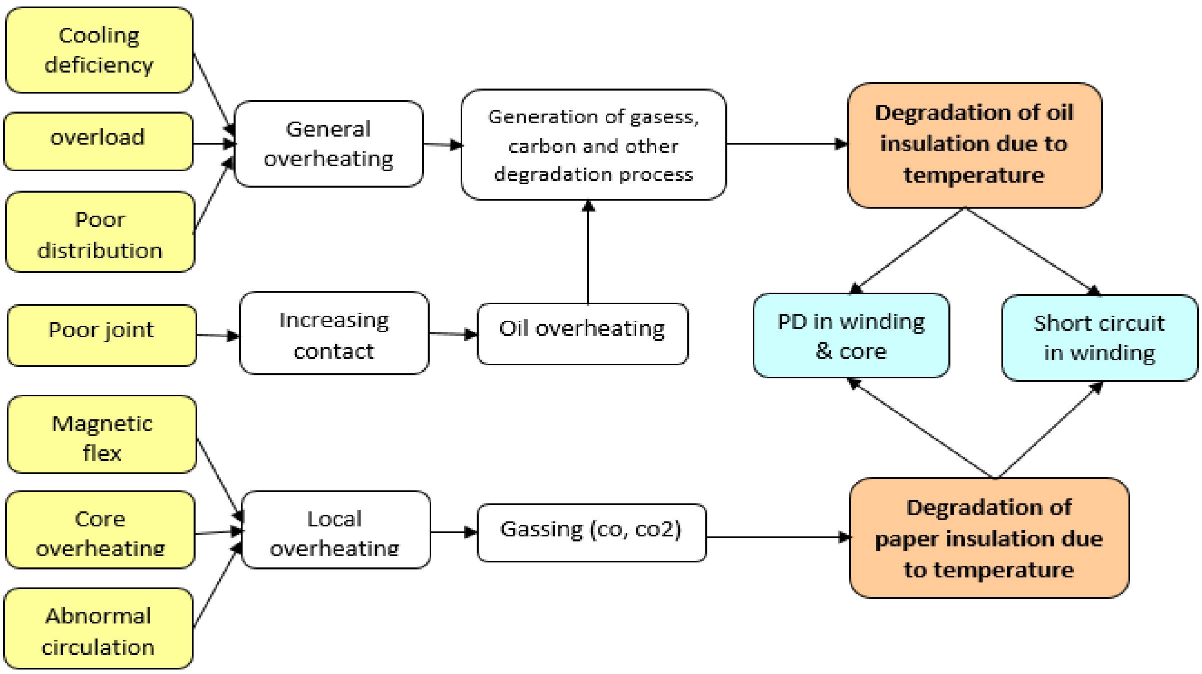

Figure 2.13: Causes and effects for oil/paper failure due to temperature

d) Degradation due to aging of oil and paper insulation :

The causes for the aging of oil and paper insulation are shown in Figure 2.14. Various internal and external faults such as an external heavy short circuit, inrush currents, overloading, continuous operation in higher temperature, moisture migration, operating in the hazardous environment will change the transformer oil/paper performance. Under these conditions, thermal and electric faults generate various gases such as H_2, CH_4, CH_2, C_2H_4 and C_2H_6 and CO, $CO_2$and H_2O. These gases are formed under various temperature ranges resulting in degradation either in the oil or in the paper [32].

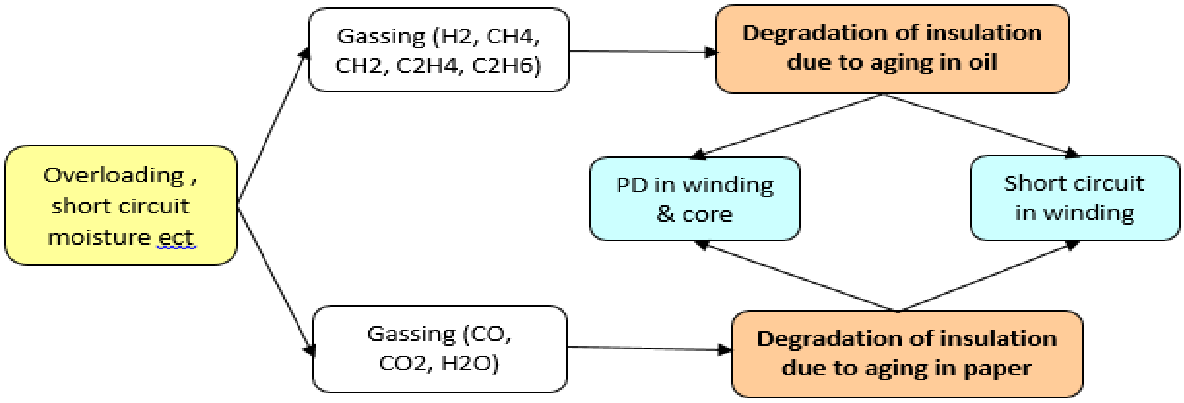

Figure 2.14: Causes and effects of oil-paper insulation aging

2.2.10 Bushing failure:

The causes for bushing failure are shown in Figure 2.15. The function of the bushings is to isolate electrical between tank and windings and to connect the windings to the power system outside the transformer. The main failure mode of the bushing is short circuit. A short circuit in the bushing can either happen due to material faults in the isolation or due to damage. A damage on bushings of porcelain can occur due to earthquakes or sabotage, like stone throwing. [34]. It is important that the gasket between the transformer tank and the bushing are absolutely tight so that no air or water are allowed to enter the transformer. It is important that the oil level remains on a normal level. If the transformer is situated in a highly polluted environment the bushings shall be washed regularly [35].

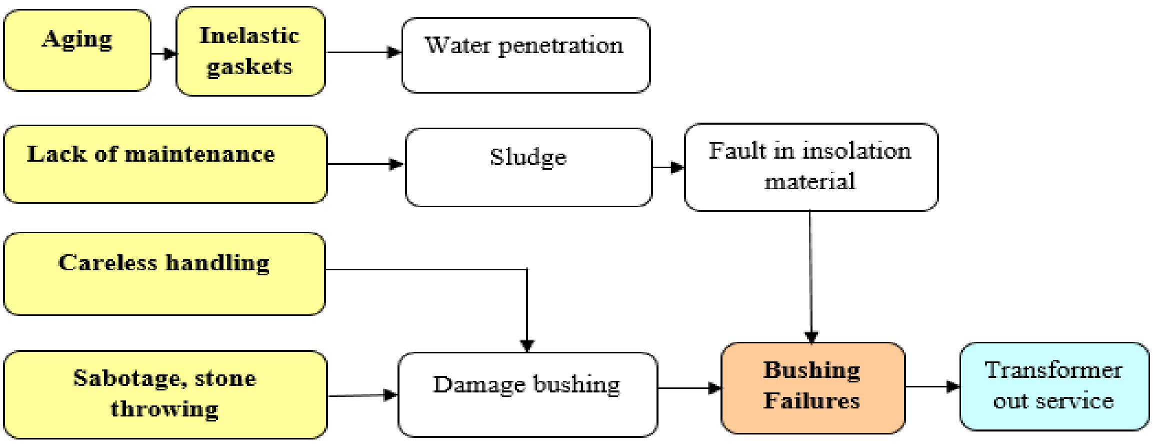

Figure 2.15: causes and effects of short circuit in bushing failure

2.2.11 Coking of contact and burnt resistance in tap changer:

The causes for coking of contact and burnt resistance in tap changer are shown in Figure 2.16. Because OLTCs are operated while the transformer is still loaded, they are more exposed to stresses than DETCs. Of course, OLTCs can experience the same coking problems, but OLTCs are usually operated automatically and are rarely left in the same position for a long period of time. However, because they are frequently operated, the mechanical wear of the switching mechanism is a considerable source to tap changer failures. Operation of the OLTC is performed by a complex mechanical system composed of several components [3]. And when there is high current pass through the resistance of contact, which might lead to a high temperature that can damage this resistance.

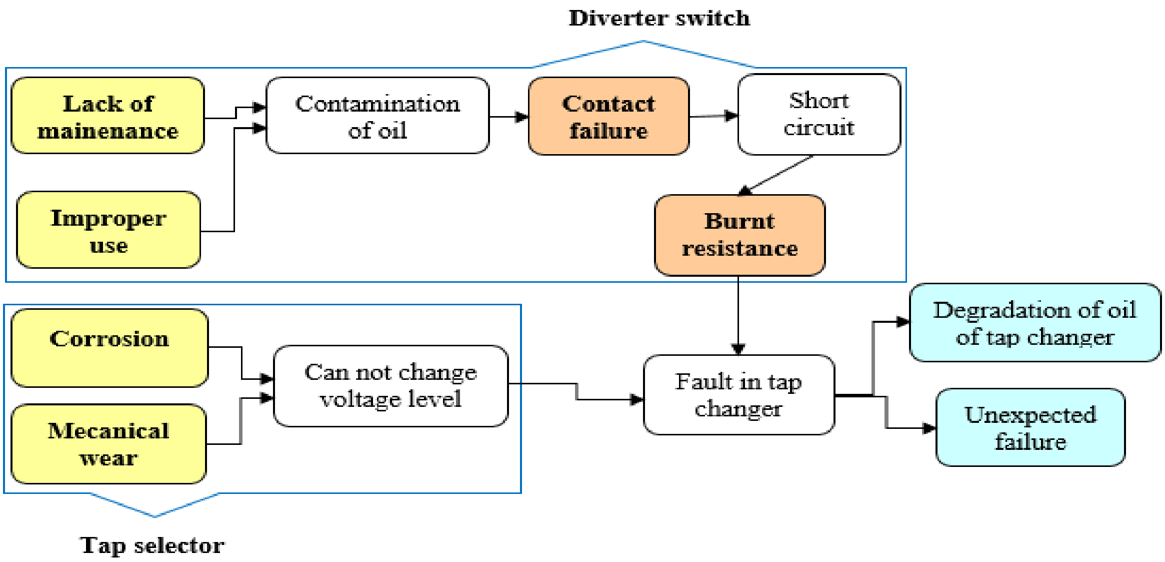

Figure 2.16: causes and effects of coking of contact and burnt resistance in tap changer

2.3 Conclusion

In this chapter, investigation of the critical failure modes, causes and their effects for predominant failure component of insulation (oil and paper) and active part (winding, core, bushing and tap changer) of the power transformers were studied using the logic tree technique which appears that any failure cannot effect just one component and this is the complexity of operation of transformer. Appendix A, discuss some other failures.

CHAPTER III:

Health Index model

3.1 WHAT IS A HEALTH INDEX?

The Health Index (HI) represents a practical tool that combines the results of operating observations, field inspections, and laboratory testing into an objective and quantitative index, providing the overall health of the asset. Asset HI is a powerful tool for managing assets and identifying investment needs as well as prioritizing investments in capital and maintenance programs [3]. The objective of this paper is to present a condition-based asset management tool that quantifies power transformer degradation and allows for a recommendation regarding the number of power transformers that would likely require replacement within future time horizons. A capital plan for replacement of power transformers is also presented. [44]

The calculated HI score is a result of interaction between different routine and diagnostic tests that are not considered by the classical condition monitoring techniques [45]. Thus, the calculated HI can identify the transformers that are close to their end-of-life and differentiate the transformers that have a higher probability of failure [46-47]. This information helps utilities to manage their assets appropriately, through clearly identifying the transformers that need more attention or major capital expenditure.

3.2 General Concepts of Health Indexing:

Health indexing of power transformers is often performed with a special emphasis on assessing the long term reliability of an asset, rather than its short term functionality [48]. Health index models are therefore normally constructed to consider factors that affect the useful lifetime as more serious than those that can be reversed by maintenance. In [48], the objectives of a health index are described as follows:

- The index should be indicative of the suitability of the asset for continued service and representative of the overall asset health.
- The index should contain objective and verifiable measures of asset condition, as opposed to subjective observations.
- The index should be understandable and readily interpreted.

Because a transformer consists of several subsystems, separate modules that describe the degradation of each subsystem can be developed. Health indexes are therefore sometimes referred to as composite health indexes [48]. How these modules affect the final health index verdict depends on the different failure mechanisms the transformer might experience, which in turn depends on manufacturing design, environment and operating conditions. Although considerable variations exist when it comes to design and construction details, most power transformer follow the same basic construction principles. This makes it possible to design a tool that to a large extent is able to assess the technical condition of transformers of various ratings and for various fields of application. Different designs are however also important to incorporate in the model where these are known to, or expected to, play a significant role on the technical condition of the transformer.

A principled illustration of how a health index might be constructed is shown in Figure 3.1. In this figure it can be seen that the input data are processed into a score by assessment function modules. These scores are further weighted relatively to each other and finally summarized to calculate a final health index score. [3]

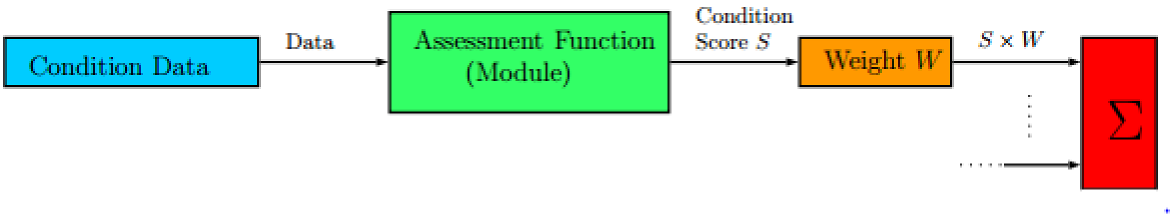

Figure 3. 1: Principled schematic of a health index model

The challenging task in any HI calculation is to identify the most significant measurements and incorporate them through justified weightings. One of the established practices of many utilities is to use the recommended conditional score and weighting factors supplied by industry standards organizations such as IEEE, IEC and CIGRE and combine the test results in a linear way. Mathematically, the linear approach can be expressed by the following equation (1):

$$h(x) = \frac{w1x1+w2x2+\cdots+wnxn}{w1+w2+\cdots+wn} \quad (1)$$

Where $\boldsymbol{h}$ is a health index metric, **w** and **x** represent the weight and conditional score of each test respectively and **n** represents the number of tests included in a HI calculation.

In Algeria, as in most other parts of the world, most power transformers are subject to a maintenance scheme where several routine measurements are conducted.

3.3 Condition Monitoring and Diagnostic Tests:

After installing and commissioning power transformers, utilities always expect to operate them continuously throughout their service life with a minimum of casual maintenance. To reduce unplanned outages and minimize operational cost, a number of routine and diagnostic tests are regularly conducted by utilities to assess the insulation condition and mechanical integrity of each transformer. A review on conventional and sophisticated routine and diagnostic tests has briefly been discussed in the following sections.

3.3.1 Dissolved Gas Analysis (DGA) (ASTMD 2612):

Over time, electrical and thermal stresses on a transformer's insulating materials (arcing, corona discharge, sparking, and overheating) can result in incipient transformer faults. As these stresses accumulate, the insulating materials will breakdown and release several different gases. These gases can be detected in transformer insulating oil using sensitive and reliable techniques (DGA) for determining the type of pending or occurring fault. [51]

DGA is considered the best method for determining a transformer's overall condition and is now a universal practice. Advantages of DGA include:

1. Advanced warning of developing faults.
2. Status checks on new and repaired units.
3. Convenient scheduling of repairs.
4. Monitoring of units under potential overload conditions.

The use of appropriate DGA diagnostic methods can provide improved service reliability, avoidance of transformer failure, and deferred capital expenditures for new transformer assets. To ensure success, we will discuss the tools available for DGA and how to properly interpret the results [51].

3.3.1.1 Formation of Gases in Transformer Oil:

Thermal and electrical stresses that occur within normal operating transformers generate hydrocarbon gases which can indicate potential problems within the transformer. Some gas generation is expected as transformers age, so it is important to separate normal gassing rates from excessive gassing rates. Since normal gas generation varies with transformer design, loading, and the type of insulating material used, general gassing rates are used for all transformers to define abnormal behaviour.

Typical gases that appear in transformers are hydrogen (H_2), methane (CH_4), ethane (C_2H_6), ethylene (C_2H_4), and acetylene (C_2H_2). These gases begin to form at specific temperatures and dissolve within the insulation oil of a power transformer, as shown in Figure 3.2. The types and quantities of the gases that form will depend on the nature and intensity of the fault [51].

It should be noted that small amounts of H_2, CH_4, and CO are produced by normal aging. Thermal decomposition of oil impregnated cellulose produces CO, CO_2, H_2, CH_4, and O_2. Decomposition of cellulose insulation begins at only about 100 ºC or less. Therefore, operation of transformers at no more than 90 ºC is imperative. Faults will produce internal "hot spots" of far higher temperatures than these, and the resultant gases show up in the DGA [51].

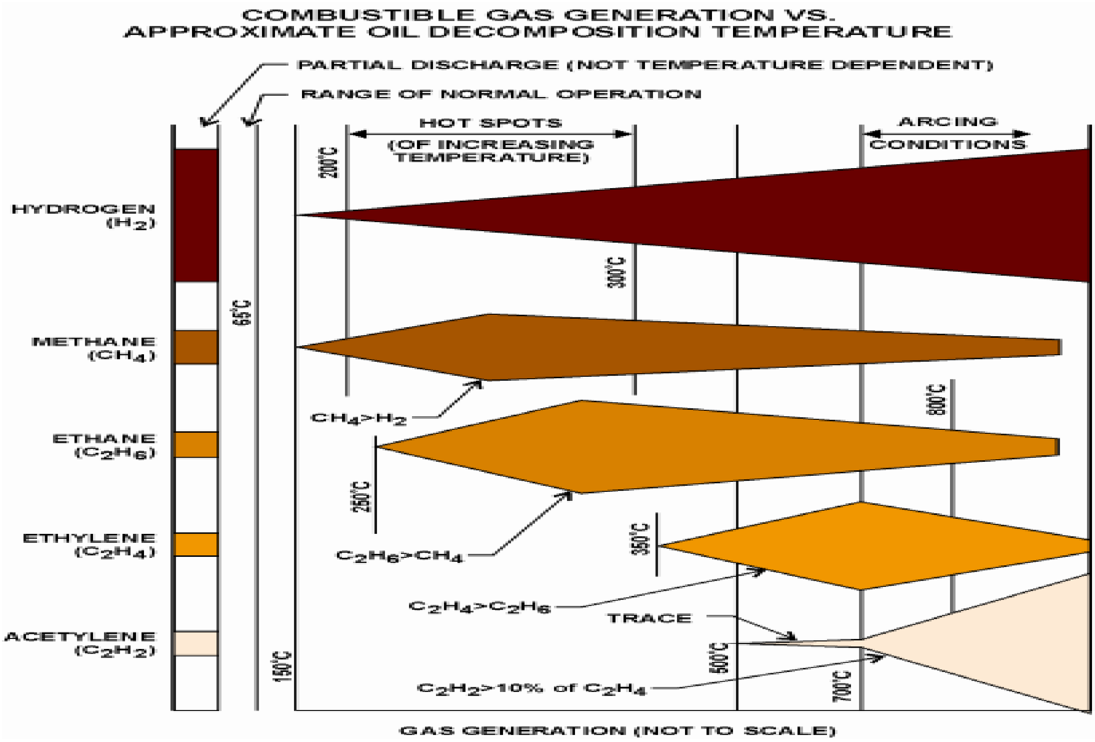

Figure 3. 2: Combustible Gas Generation versus Temperature

3.3.1.2 Types of Fault:

A proper fault diagnosis will include warnings of any gases with concentrations, increments, rates of change, or ratios that exceed the standard limits, along with short interpretive remarks and recommendations based on the findings. To help identify the different faults when a diagnosis is being made, the following classes have been identified after the physical inspection of hundreds of faulty transformers detectable by visual inspections and DGA results [51]. They are also summarized in Table 3.1.

Table 3. 1: Types of fault [51].

Abbreviation	Description
PD	Partial Discharges
D1	Discharges of Low Energy
D2	Discharges of High Energy
T1	Thermal Fault t < 300°C
T2	Thermal Fault 300°C < t < 700°C
T3	Thermal Fault t > 700°C

3.3.1.3 DGA Diagnostic Tool Selection:

a. **IEC 60599-1999 reference standard:**

- **IEC Ratio Analysis**

It is taking similar ratios of Rogers's ratio method except C_2H_6/CH_4; even it is similar ratios of Roger's ratio method but does not diagnosis the same faults because it considered different ranges for corresponding gas ratios. Hence the ratio ranges and their code representation and the indication of faults for every case are different compare to Roger's ratio method [52]. Table 3.2 indicates ratio codes, gas ratio ranges in ppm.

Table 3. 2: IEC code [53]

Gas Ratio	Value	Code
$R_1=C_2H_2/C_2H_4$	$R_1<0.1$	0
	$0.1\leq R_1\leq 3$	1
	$R_1>3$	2
$R_2=CH_4/H_2$	$R_2<0.1$	1
	$0.1\leq R_2\leq 1$	0
	$R_2>1$	2
$R_3=C_2H_4/C_2H_6$	$R_3<1$	0
	$1\leq R_3\leq 3$	1
	$R_3>3$	2

Table 3. 3: Fault diagnostic using IEC code [53]

No.	Fault Type	Code		
		R_1	R_2	R_3
1	NF	0	0	0
2	UD			
3	PDLED	0	1	0
4	PDHED	1	1	0
5	LED	1or 2	0	1 or2
6	HED	1	0	2
7	LTH1	0	0	1
8	LTH4	0	2	0
9	MTH	0	2	1
10	HTH	0	2	2

NF: No fault (normal), UD: Undetermined fault, PDLED: Partial discharge with low energy density, LED (Dl): Arc with low energy density, LTH (Tl) Low temperature thermal overloading, LTH1: Thermal fault <150°C, LTH4: Thermal fault with temperature between 150 to 300°C, MTH (T2): [Thermal fault (temperature < 700 °C), and Thermal fault with temperature between 300 to 700°C], HTH (T3): Thermal fault (temperature > 700 °C) [53].

- **CO2/CO Ratio:**

This popular ratio is used to detect paper involvement in a fault. If the ratio is below 3, it is a strong indication of a fault in paper, either a hot spot or electrical arcing with a temperature above 200 °C. If the ratio is above 10, it indicates a fault with a temperature below 150 °C. However, this ratio is not very accurate because it is affected by the CO2 and CO coming from oil oxidation and normal cellulose aging, so with a high quantity of CO2, seeing a significant change in the CO2/CO ratio is nearly impossible [51].

- **O2/N2 Ratio:**

A decrease of this ratio indicates excessive heating [51].

- **C2H2/H2 Ratio:**

A ratio between 2 and 3 in the main tank indicates contamination by the LTC compartment. In these situations the level of acetylene in the main tank can be quite high, so in order to diagnose true main tank problems, incremental changes in acetylene must be monitored [53].

- **Dival Triangular:**

The Duval Triangle diagnostic method for oil-insulated high-voltage equipment, mainly transformers, was developed by Michel Duval in 1974. It is based on the use of 3 hydrocarbon gases (CH4, C2H4 and C2H2) corresponding to the increasing energy levels of gas formation in transformers in service. This method has proven to be accurate and dependable over many years and is now gaining in popularity. One advantage of this method is that it always provides a diagnosis, with a low percentage of wrong result. Duval method is special since fault diagnosis is performed based on visualisation of the location of dissolved gases in the triangular map. The Triangle method is indicated in figure 3.3. [54]

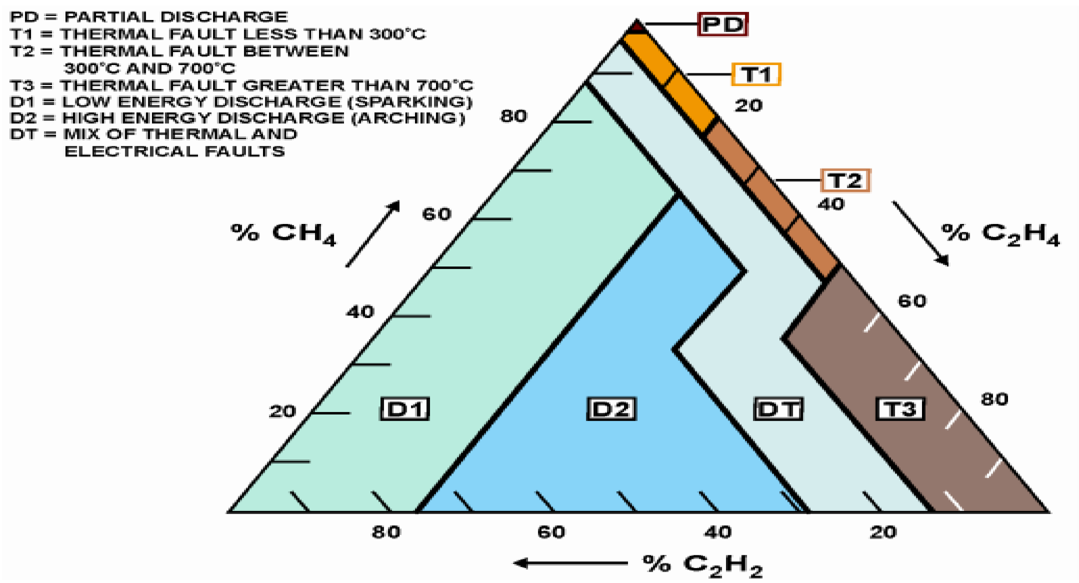

Figure 3. 3: The Duval Triangle

Generally, the faults that can be detected by this method will be determined in 6 zones of individual faults mentioned in Table 3.1 (PD, D1, D2, T1, T2 or T3), an intermediate zone DT has been attributed to mixtures of electrical and thermal faults in the transformer. Since no region is designated for normal ageing condition, careless implementation of Duval triangle will result in the diagnosis of either one of the mentioned faults. To avoid this problem, dissolved gases should be assessed for their normality before being interpreted using Duval triangle [54].

b. IEEE C57.104-1991

- **Four-Condition DGA Guide**

Table 3. 4: Dissolved Key Gas Concentration Limits

Status	H_2	CH_4	C_2H_2	C_2H_4
Condition 1	100	120	35	50
Condition 2	101-700	121-400	36-50	51-100
Condition 3	701-1,800	401-1,000	51-80	101-200
Condition 4	>1,800	>1,000	>80	>200
Status	C_2H_6	CO	CO_2[1]	TDCG[2]
Condition 1	65	350	2,500	720
Condition 2	66-100	351-570	2,500-4,000	721-1,920
Condition 3	101-150	571-1,400	4,001-10,000	1,921-4,630
Condition 4	>150	>1,400	>10,000	>4,630

3.3.2 Oil quality:

The New Transformer oil before filling into a Transformer has to undergo stringent quality tests, as per IEC 60296 Standard specifications. Critical and basic characteristics like Density, Interfacial Tension, Flash Point, Pour Point, Electric Strength, Moisture Content, Dielectric Dissipation Factor …etc. are needed to be analysed. Similarly, the In-service Transformer oil is also required to be analysed as per IEC 60422 standard specifications [57].

Oil quality testing is performed to check the general condition of insulating oil. The evaluation of oil quality is performed by considering six testing: Dielectric Strength, Interfacial Tension (IFT), Neutralization Number (NN) or Acidity, Water Content, Color and Power Factor.

a. Dielectric breakdown voltage (IEC60156):

Dry and clean oil exhibits an inherently high breakdown voltage. Free water and solid particles, the latter particularly in combination with high levels of dissolved water, tend to migrate to regions of high electric stress and reduce breakdown voltage dramatically. The measurement of breakdown voltage, therefore, serves primarily to indicate the presence of contaminants such as water or particles. A low value of breakdown voltage can indicate that one or more of these are present. However, a high breakdown voltage does not necessarily indicate the absence of all contaminants [62-65].

b. Interfacial Tension (ISO 6295):

The interfacial tension between oil and water provides a means of detecting soluble polar contaminants and products of degradation. This characteristic changes fairly rapidly during the initial stages of ageing but levels off when deterioration is still moderate. A rapid decrease of IFT may also be an indication of compatibility problems between the oil and some transformer materials (varnishes, gaskets), or of an accidental contamination when filling with oil [59].

c. Acid Number (IEC62021):

Acid number is the amount of potassium hydroxide (KOH) in milligrams (mg) that it takes to neutralize the acid in 1 gram (gm) of transformer oil. The higher the acid number, the more acid is in the oil [58]. Acids and other oxidation products will, in conjunction with water and solid contaminants, affect the dielectric and other properties of the oil. Acids have an impact on the degradation of cellulosic materials and may also be responsible for the corrosion of metal parts in a transformer [61].

d. Water content in insulating liquid (IEC 60814):

Oil serves as a water-transferring medium within a transformer. In a transformer, the total mass of water is distributed between the paper and the oil such that the bulk of water is in the paper. Thus, for the proper interpretation of moisture content the analytical results need to correct the water content of the oil at a given sampling temperature to the content at a defined temperature. [63]

e. Color (ISO 2049):

Mineral oil should have a light color and be optically clear so that it permits visual inspection of the assembled apparatus inside the equipment tank. Any change in the color of oil over time is an indication of oxidation, deterioration, or contamination of the oil [64].

f. Dissipation factor (IEC 247):

The Dissipation factor is very sensitive to the presence of soluble polar contaminants, ageing products or colloids in the oil. Changes in the levels of the contaminants can be monitored by measurement of these parameter even when contamination is so slight as to be near the limit of chemical detection [58].

3.3.3 Furanic Analysis (IEC 61198):

Degradation of transformer paper insulation can be assessed by direct measurement of the paper's degree of polymerization (DP) and tensile strength (TS). Transformer winding paper begins to degrade noticeably at temperatures of about 100–110 °C, and for every 6–10 °C rise the degradation rate approximately doubles. Overheating can cause cellulose decomposition and production of CO and CO2. These two gases can also be produced during thermal decomposition of the oil. Therefore, analysis of CO and CO2 cannot be used as an unambiguous indication of paper degradation [49].

Accompanying this paper degradation is the release of a chemical compound furfuraldehyde (FFA) into the oil. The monitoring of Furanic compounds by oil analysis using High Performance Liquid Chromatography (HPLC) has been used widely by utilities for the last few decades.

Measuring FFA within oil samples collected periodically from power transformers is usually carried out as a means of transformer condition monitoring. The furfural test is much more convenient than DP or TS measurements, for which the transformer needs to be taken offline and opened to collect paper samples from the windings. [49]

3.3.3.1 Paper Degradation and Furan Formation:

As mentioned before, paper/pressboard insulation contains about 90% cellulose, 6–7% hemicellulose, and 3–4% lignin. Transformer insulation during operation is affected by thermal and electrical stress, moisture, and oxidation. Six furans are found in the oil, which are:

- 2-furfural (2-FAL)
- 5-methyl-2-furfural (5-MEF)
- 2-acetylfuran (2-ACF)
- 2-furfurylalcohol (2-FOL)
- 2-furoic acid
- 5-hydroxymethyl-2-furfural (5-HMF)

Oil maintenance also has a strong influence on the 2-FAL formation and retention in the oil, as discussed extensively in this brochure. “Although 2-FAL seems to be the most popular thermal ageing marker” The proposed diagnosis model is presented in Table 3.5. [49]

Table 3. 5: Possible causes of specific Furanic compound presence

Compound	Diagnosis proposed
5-HMF	Oxidation
2-FOL	High moisture
2-FAL	General overheating or normal ageing
2-ACF	Rare, causes not fully defined
5-MEF	High temperatures

DP Measurements:

a. Paper Ageing and DP:

Cellulose is a linear polymer composed of individual anhydrous glucose units linked at the first and fourth carbon atoms through a glucosidic bond. The structure of glucose and cellulose is shown in Figure 3.4.

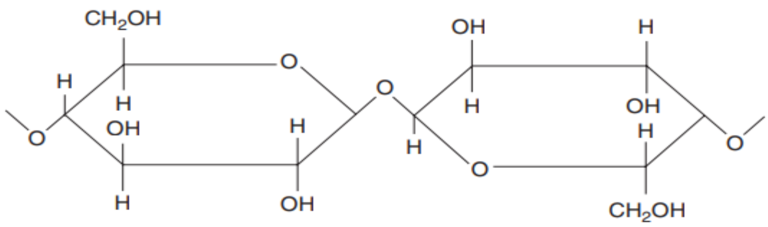

Figure 3. 4: Structure of cellulose.

Cellulose has the molecular formula $(C_6H_{10}O_5)_n$ (the end units are slightly different), where $(C_6H_{10}O_5)$ denotes an anhydroglucose unit and n is the DP.

The strength of paper is critically dependent on the DP of the cellulose. During paper manufacture, the pulping process and subsequent washing and drying reduce the DP of the cellulose in the paper to the range 1000 to 1500. After a long period of service at high temperature with high content of water and oxygen, the paper becomes brittle, changes color to dark brown, and its DP drops to the range 200 to 250. [49]

b. Insulation Life Prediction from DP Measurements

As mentioned before, DP has been used widely to predict the remaining life of aged power transformers. However, DP measurements require the transformer to be de-energized and paper samples collected from the transformer, which is cumbersome and time-consuming. Many researchers have attempted to correlate DP with furfural content by using generally this general model:

$$\text{Log}\,[2FAL] = A - B \times [DP] \qquad (2)$$

The other most discussed models in literature are those of:

- ➔ Chendong
- ➔ De Pablo
- ➔ Burton and
- ➔ Paul Vuarchex

The Chendong model is expressed as shown in equation 3:

$$DP = \frac{\log\,(2FAL) - 1.51}{-0.0035} \qquad (3)$$

De Pablo came with the model that is given by:

$$DP = \frac{8.88 * \mathrm{DP0}}{8.88 + 2FAL} = \frac{7100}{8.88 + 2FAL} \qquad (4)$$

The Burton equation is as follows: $\text{Log}\,(2FAL) = 2.5 - 0.005 * DP \qquad (5)$

Finally, the Paul Vuarchex equation (7) is as follows:

$$\text{Log}\,(2FAL) = 2.6 - 0.0049 * DP \qquad (6)$$

The models where in the DP value is calculated from 2FAL present a better estimation of the DP value if compared to the earlier models where a hot spot gradient and its time duration are used to calculate lost life. [49]

3.3.4 Power Factor (dissipation factor):

The power factor or dissipation factor measurement is an important source of data to monitor transformer and bushing conditions. This test is performed to determine the condition of capacitive insulation between different windings and compartments. The measurement of transformer insulation's capacitance and power factor at voltages up to 10 kV (at 50 or 60 Hz) has long been used both as a routine test and for diagnostic purposes [69]. Though dielectrics have inherent losses due to construction materials, PF measurement is most effective at detecting the relative levels of moisture and contamination. Evaluation of the capacitance measurement is effective in detecting physical defects that lead to changes in the dielectric's geometry.

Power factor (Tan delta) test is used to check the insulation integrity in windings, bushings and oil tank of transformers. Then, it is a measure of the ratio of the power (I^2R) losses to the volt-amperes applied during the test [4]. When an alternating (AC) voltage is applied across the insulation, a leakage current having reactive (Ic) (capacitive) and resistive components (Ir) starts to flow. The magnitude of the resistive component is dependent on the moisture, ageing and conductive contaminants in the oil, while the capacitive current is dependent on the frequency. The ratio of resistive and capacitive current is known as the dissipation factor or power factor [68]. Del (δ) is represented as loss angle. [67]

3.3.4.1 Overall Power Factor Test:

The Overall Power Factor Test is used to test the integrity of the insulation system of a transformer and can identify the following insulation defects:

- Naturally aged, deteriorated, and/or contaminated insulation
- Moisture ingress, which is one of the main "transformer killers"
- Localized insulation failures, such as a partial or full short-circuit to ground, or between the windings [71]

There are three type of measurement:

1. **CH:** The high-voltage winding-to-ground insulation system, including the primary-side (H) bushing insulation that is heavily influenced this test, which make up approximately 50% of the CH measurement.

2. **CL:** The low-voltage winding-to-ground insulation system, including the secondary-side (X) bushing insulation that influenced this test, and make up approximately 10% of the CL measurement.
3. **CHL:** The high-voltage to low-voltage (inter-winding) insulation system, which does not include the bushing insulation which is not influenced by the bushings. This test is the most robust measurement (the most resistant to the test environment) and the best measurement for assessing the condition of the paper insulation, since most of the paper insulation is located between the primary and secondary windings. CHL test can use as an indicator of moisture within the transformer and for assessing the condition of the main-tank insulation system [71].

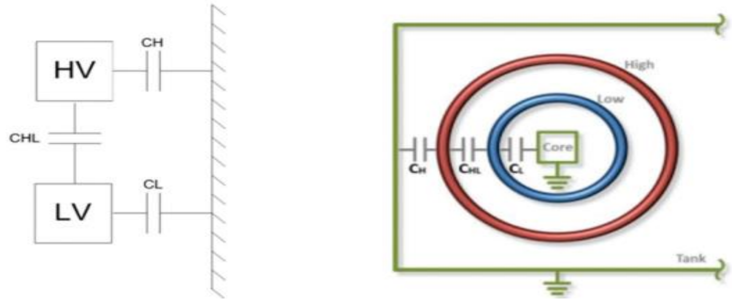

Figure 3. 5: representation of different capacitance of transformer [72]

3.3.4.2 Test modes:

a. Grounded specimen test (GST):

The GST configuration permits testing of a grounded insulation specimen through the specimen's ground. All current flowing to ground is measured via the meter circuit. The configuration is illustrated in Figure 3.6.

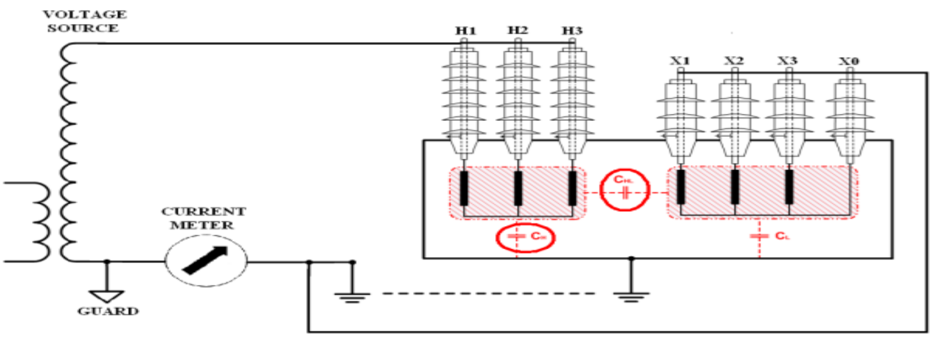

Figure 3. 6: Grounded specimen test circuit [71]

b. Ungrounded specimen test (UST):

The UST configuration is used for measurements between two terminals of a test specimen that are not grounded or that can be removed from ground. In the UST configuration, current flowing in the insulation between the voltage lead and the measuring lead of the instrument is measured and current flowing to ground is not measured. The test configuration also shifts the ground of the test circuit to the guard point to the left of the meter, allowing the ground current to bypass the metering circuit. This configuration is illustrated in Figure 3.7.

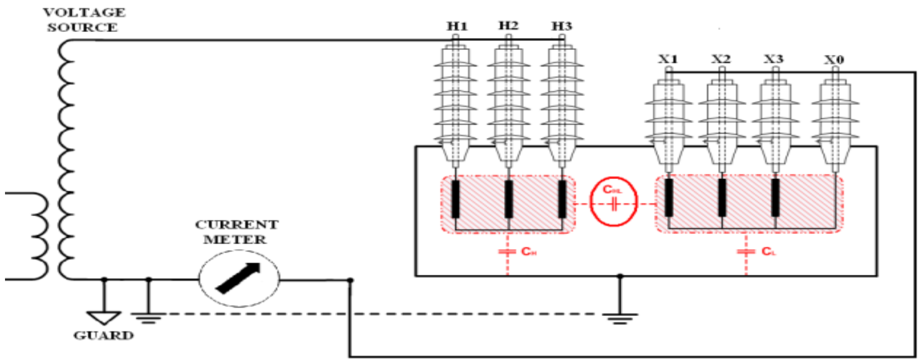

Figure 3. 7: Ungrounded specimen test circuit [71]

c. Grounded specimen test with guard:

The GST-Guard configuration allows unwanted currents to bypass the measuring circuit and enables smaller sections of insulation to be tested individually. Only the ground currents are measured using a GST-Guard configuration. Current flowing to terminals with the guard connection is not measured. This configuration is illustrated in Figure 3.8.

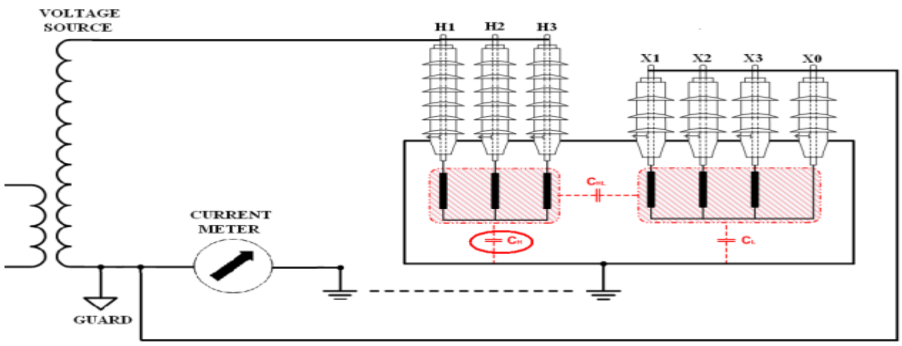

Figure 3. 8: Grounded specimen with guard test circuit [71]

3.3.4.3 Bushing Power Factor Testing (IEC 137):

Bushings provide an insulated path for energized conductors to enter grounded electrical power apparatus. Bushings are a critical part of the electrical system that transforms and switches ac voltages ranging from a few hundred volts to several thousand volts. Bushings not only handle high electrical stress, they could be subjected to mechanical stresses, affiliated with connectors and bus support, as well. Although a bushing may be thought of as somewhat of a simple device, its deterioration could have severe consequences [73].

Performing routine power factor measurements on bushings is critical for extending the life of a power transformer, so bushing insulation problems can be detected by performing periodic electrical tests:

1. The C1 Power Factor Test (bushing tap required): the most-valuable test for assessing the condition of a bushing's insulation system.
2. The C2 Power Factor Test (bushing tap required): we do recommend performing the C2 PF test.
3. The Energized/Hot Collar Test (no bushing tap required): the value of this test should be questioned, and the cost-to-benefit ratio should be considered when building a maintenance testing plan [71].

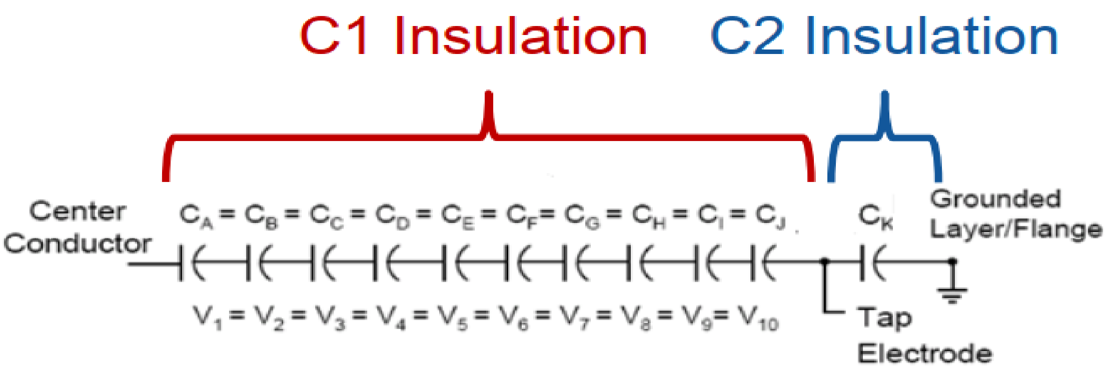

Figure 3. 9: A typical condenser bushing design [74]

a. C1 Power Factor Test – Test Procedure

1. Place the high-voltage lead on the center-conductor of the bushing under test, or anywhere on the short-circuited electrode.

2. Place the current measurement lead on the tap of the bushing. Note, a tap-adapter may be required, depending on the bushing type.

3. Perform an UST, to measure the C1 insulation system of the bushing under test.

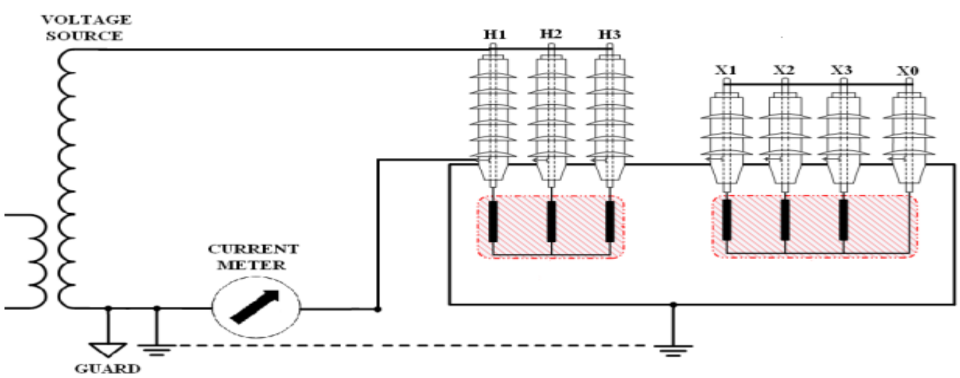

Figure 3. 10: Ungrounded specimen test circuit (C1) [71]

b. C2 Power Factor Test – Test Procedure

• Place the high-voltage lead on the tap of the bushing under test. Note, a tap-adapter will probably be required for the C2 test.

• Place the current measurement lead on the center conductor of the bushing under test, or anywhere on the short-circuited electrode (if the bushings are shorted together).

• Perform a GST with Guard (GST-Guard) to measure the C2 insulation system of the bushing under test.

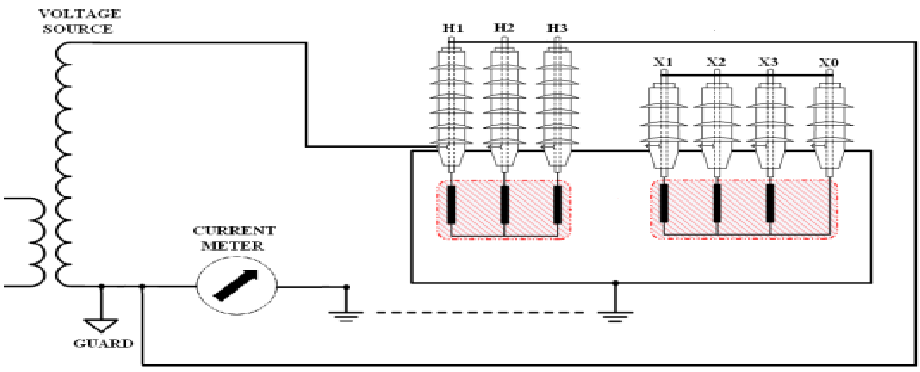

Figure 3. 11: Grounded specimen with guard test circuit (C2) [71]

3.3.5 Load History:

Load factor is the ratio of the average load over a designated period to the peak load occurring in that period.

Peak load is the maximum load consumed or produced by a unit or group of units in a stated period of time. It may be the maximum instantaneous load or the maximum average load over a designated interval of time. Maximum average load is ordinarily used. In commercial transactions involving peak load (peak power) it is taken as the average load (power) during a time interval of specified duration occurring within a given period of time, that time interval being selected during which the average power is greatest [75].

As discussed in before, temperature, and thus load, plays a significant role when it comes to the condition of the solid insulation of the windings. In the health index model the load history is represented by the load factor (LF), which takes into account the load peak Si of every month. The ratio between the monthly load peak and the rated loading SB of the transformer is then calculated for every month. From this procedure, transformers that are heavily loaded will receive a low LF while lightly loaded transformers will receive a high load factor. [3]

3.3.6 Infrared scanning:

3.3.6.1 Infrared Temperature Analysis

Infrared analysis should be conducted annually while equipment is energized and under full load, if possible. IR analysis should also be conducted after any maintenance or testing to see if connections that were broken were re-made properly. Also, if IR is performed during factory heat run, the results can be used as a baseline for later comparison [54].

3.3.6.2 IR for Transformer Tanks

Unusually high external temperatures or unusual thermal patterns of transformer tanks indicate problems inside the transformer, such as low oil level, circulating stray currents, blocked cooling, loose shields, tap changer problems, etc. Thermal patterns of transformer tanks and radiators should be cooler at the bottom and gradually warmer ascending to the top. See figure 3.12 for a normal pattern; the red spot at the top is normal showing a "hot spot" top of B phase, about 110 degrees Fahrenheit (°F). [54]

Figure 3. 12: IR for Transformer Tanks

3.3.6.3 IR for Surge Arresters

Surge arresters should be included when infrared scanning energized transformers. Look for unusual thermal patterns on the surface of lightning arresters (the arrester IR in figure 3.13). Note that the yellow in the top right of the image is a reflection not associated with the arrester. This indicates that immediate de-energization and replacement must be undertaken. [54]

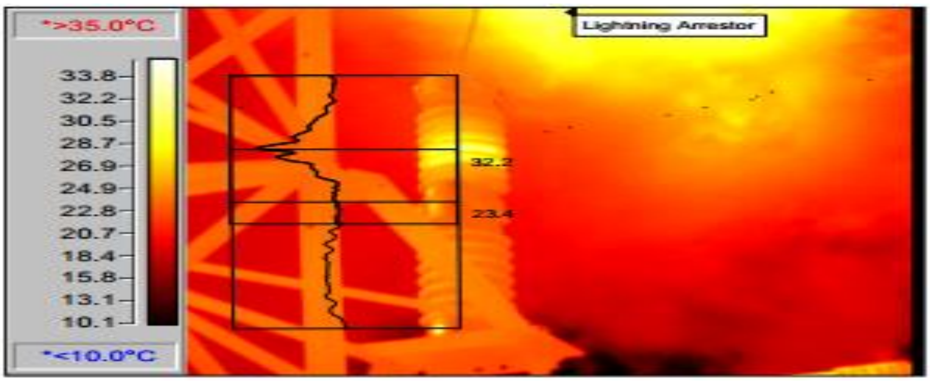

Figure 3. 13: IR for Surge Arresters

3.3.6.4 IR for Bushings

IR scans of bushings can show low oil levels which would call for immediate de-energization and replacement. This generally means that the seal in the bushing bottom has failed, leaking oil into the transformer. The top seal has probably also failed, allowing air and water to enter up the bushing. Remember, over 90% of bushing failures are attributed to water entrance through the top seal. Figure 3.14 shows low-oil level in a high-voltage transformer bushing. [54]

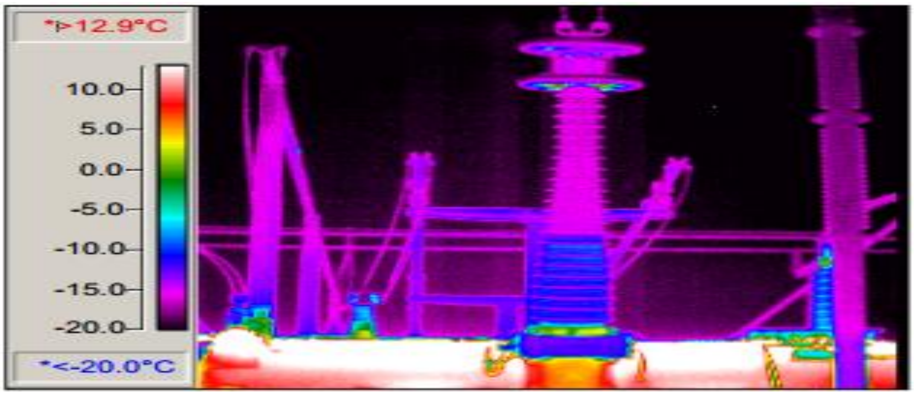

Figure 3. 14: IR for Bushings

3.3.6.5 IR for Radiators and Cooling Systems

Examine radiators with an IR camera and compare them with each other. A cool radiator or segment indicates that a valve is closed or the radiator or segment is plugged. The IR image (figure 3.15) shows that the cold left radiator section is valved off or plugged.. Do not allow a transformer to operate with reduced cooling which drastically shortens transformer life. [54]

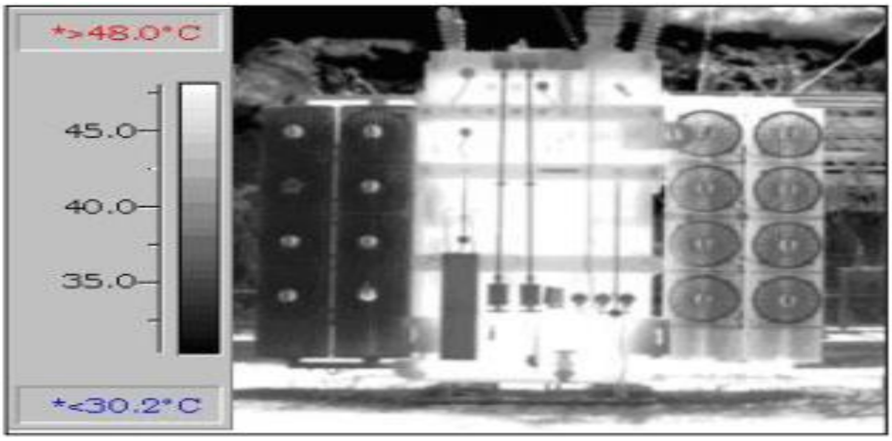

Figure 3. 15: IR for Radiators and Cooling Systems

3.3.7 Maintenance History:

The primary purpose of transformer maintenance is to ensure the internal and external parts of the transformer and accessories are kept in good condition and “fit for purpose” and able to operate safely at all times. A secondary and equally essential purpose is to maintain a historical record of the condition of the transformer [76].

Transformer maintenance can be done periodically or as condition based maintenance. The latter is usually the most economical way of doing maintenance. There are two type of transformer maintenance, which are:

1. Maintenance in energized condition (i.e. oil level, oil tank …etc.)
2. Maintenance in de-energized condition (i.e.: oil leaks, gaskets, electric test …etc.) [21]

The impact of the maintenance history of an asset is evaluated based on the number of corrective maintenance work orders during the last five years. Oil leak, oil level, cooling system, main tank condition, oil tank, foundation, grounding, gaskets and connectors are important factors in this evaluation [3].

3.3.8 Insulation resistance:

Insulation Resistance (IR) test of transformer is one of the most import test. This test performed on transformer in order to check the relative amount of moisture in the insulation, the leakage current over dirty or moist surfaces of the insulation, and the winding deterioration or faults [78].

IR test is made to determine insulation resistance from individual windings to ground or between individual windings. Insulation resistance tests are commonly measured directly in megohms or may be calculated from measurements of applied voltage and leakage current [79].

3.3.8.1 Procedure of Megger test

A dc voltage of 500V to 5 KV is applied to the insulation and readings are taken to the IR versus time. Data should be recorded at the 1-and 10-minute intervals and at several other intermediate times. Because the value of IR varies with applied voltage, it is important that the test instrument have sufficient capacity to maintain its rated output voltage for the largest winding being tested, and the output voltage be constant over the 10-minute test period.

IR test of transformer is divided into:

1. First disconnect all the line and neutral terminals of the transformer, discharge the winding capacitance and clean all bushing then record the temperature.
2. Apply the test voltage and note the reading. The IR value at 60 seconds after application of the test voltage is referred to as the Insulation Resistance of the transformer at the test temperature [79].

3. Megger connects to LV and HV bushing studs to calculate the importance of IR insulation resistance between LV and HV windings.
4. Megger leads to connecting to HV bushing studs and earth point transformer tanks to calculate the importance of IR insulation resistance between HV windings and earth.
5. Megger leads to the relation between the LV bushing studs and the transformer tank earth point to calculate the strength of IR insulation resistance between the LV windings and ground [80].

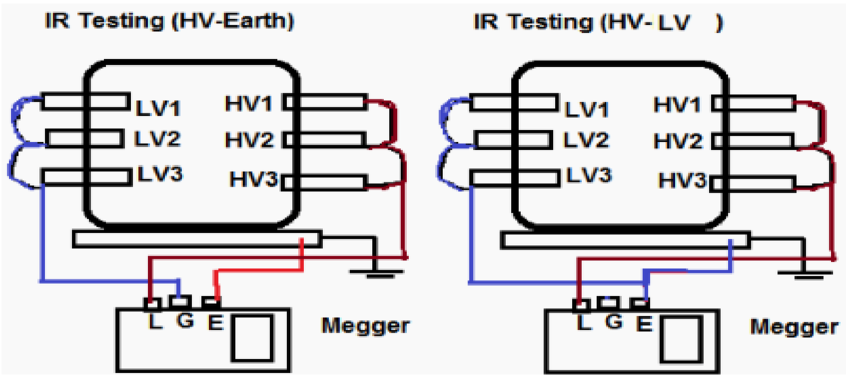

Figure 3. 16: Insulation resistance testing: HV – Earth and HV – LV [79]

Table 3. 6: IR Value of Transformers [79]

Voltage (KV)	**Test voltage (DC) LV side (KV)**	**Test voltage (DC) HV side (KV)**	***Min IR value (MΩ)***
0.415	0.5	2.5	100
Up to 6.6	0.5	2.5	200
6.6 to 11	0.5	2.5	400
11 to 33	1	5	500
33 to 66	1	5	600
66 to 132	1	5	600
132 to 220	1	5	650

3.3.9 Winding Resistance (IEC 60076-1):

Winding resistance measurements are an important diagnostic tool for assessing possible damage to transformers resulting from poor design, assembly, handling, unfavourable environments, overloading or poor maintenance. The main purpose of this test is to check for malfunctioning of tap changer mechanisms, partial or dead short-circuited turns, loose connection, broken stands and poor efficiency. Measuring the resistance of transformer windings assures that each circuit is wired properly and that all connections are tight [82].

The resistance measurements are normally made phase-to-phase and the readings are compared with each other to determine if they are acceptable for delta and wye without neutral, however the measurements are done per phase for wye with neutral connection.

Transformer winding resistance measurements are obtained by passing a known DC current through the winding under test and measuring the voltage drop across each terminal. The resistance can be measured by simple voltmeter, Ammeter method, Kelvin Bridge meter or automatic winding resistance measurement kit. [82]

3.3.9.1 Connecting to the Transformer under Test

Both the primary and secondary terminals of the transformer should be isolated from external connections, and measurements made on each phase of all windings.

a. 3-phase Delta Winding

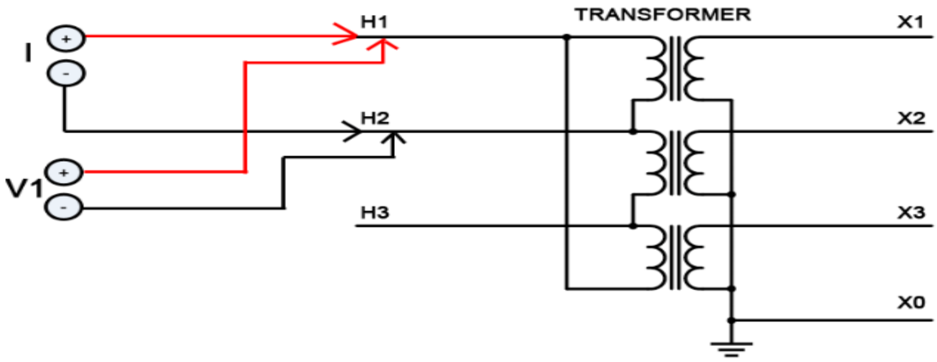

Figure 3. 17: three-phase transformer delta winding resistance test connection [82]

Table 3. 7: winding resistance test connections for 3-phase delta winding [82]

Test No.	*I+*	*I-*	*V1+*	*V1-*
A-phase	H1	H2	H1	H2
B-phase	H2	H3	H2	H3
C-phase	H3	H1	H3	H1

The resistance of individual winding can be calculated as follow:

$$\text{Resistance per winding} = 1.5 \times \text{Measured value}$$

b. 3-phase Wye Secondary Winding

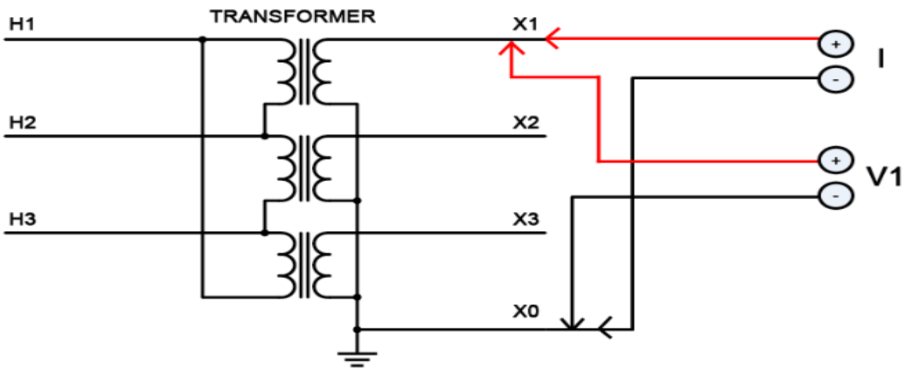

Figure 3. 18: three-phase transformer wye winding resistance test connection [82]

Table 3. 8: winding resistance test connections for 3-phase wye winding [82]

Test No.	***I+***	***I-***	***V1+***	***V1-***
A-phase	X1	X0	X1	X0
B-phase	X2	X0	X2	X0
C-phase	X3	X0	X3	X0

3.3.9.2 Obtaining Winding Resistance Measurements

When measuring winding resistance, the reading should be observed and recorded once the resistance value has stabilized. Resistance values will "drift" at first due to the inductance of the transformer, which is more prevalent in large, delta connected windings [82].

Test Results

Interpretation of winding resistance results is usually based on a comparison of each resistance value with each adjacent winding at the same tap. If all readings are within one percent of each other, the specimen is considered to have passed the test. Comparisons may also be made with original test data measured at the factory by using temperature corrected values. [82]

3.3.9.3 Temperature Correction

Because resistance is dependent on temperature, corrected values must be used whenever comparing results for trend data. It's most important to estimate the winding temperature at the time of measurement. If the transformer has a winding temperature gauge, use these readings, otherwise the winding temperature is assumed the same as the oil temperature. If the transformer is measured without oil, the winding temperature is normally assumed the same temperature as the surround air. [82]

The measured resistance should be corrected to a common temperature such as 75°C or 85°C using the following formula:

$$Rc = Rm * \frac{CF+CT}{CF+WT} \qquad (8)$$

Where:

R_C is the corrected resistance

R_M is the measured resistance

CF is the correction factor for copper (234.5) or aluminium (225) windings

CT is the corrected temperature (75°C or 85°C)

WT is the winding temperature (°C) at time of test

3.3.10 Sweep Frequency Response Analysis (IEC 60076-18):

Sweep Frequency Response Analysis (SFRA) is a diagnostic tool used to assess the mechanical and electrical integrity of power transformers. The SFRA test consists of measuring the transfer function (Vout/Vin) of a power transformer winding over a wide sweep of frequencies from 20 Hz to 2 MHZ. Winding movement and/or deformation will cause changes in the passive RLC elements of the winding transformer equivalent circuit includes core resistance and inductance as well as capacitances between the turns and the other windings, and between the winding, the tank wall, and the core., thus changing the frequency response of the transformer winding. Deviations in the SFRA Measurements can be used to identify the following mechanical failure modes:

- Radial Deformation (faults)
- Axial Deformation (faults)
- Bulk Winding Movement (transportation)

It can also identify electrical problems such as:

- Broken or Loose Connections
- Shorted Turns [85]

SFRA tests are recommended to be performed at the end of the acceptance test at the manufacturer's to establish the transformer's original fingerprint and then again after transportation, and during commissioning. [67]

Test procedure:

Step 1: Inject an AC Voltage into one end of a transformer winding (Vin)

Step 2: Measure the AC Voltage that comes out the other end of the winding (Vout)

Step 3: Calculate the ratio of the output voltage and the input voltage (Vout / Vin)

Step 4: Repeat the measurement over a broad frequency range (e.g. 20Hz – 2MHz) [71]

The comparison of input and output signals generates a unique frequency response, which can be compared with the reference fingerprint [67]. It is commonly accepted that the low frequency range (20 Hz to 2 kHz) is useful for detecting core deformation, the medium frequency range (2 to 20 kHz) determine bulk movement of winding relative to each other, the high frequency range (20 kHz to 1 MHz) can identify deformation within a winding and for frequency above this value will detect a problem with winding leads and/or test lead problem [84]. According to, the frequency response in different sections of the spectrum is shown in Figure 3.19.

SFRA is based on the comparison of a current test with a reference test. When such a fingerprint is not available, results of another phase or a similar transformer can also be used for comparison [67].

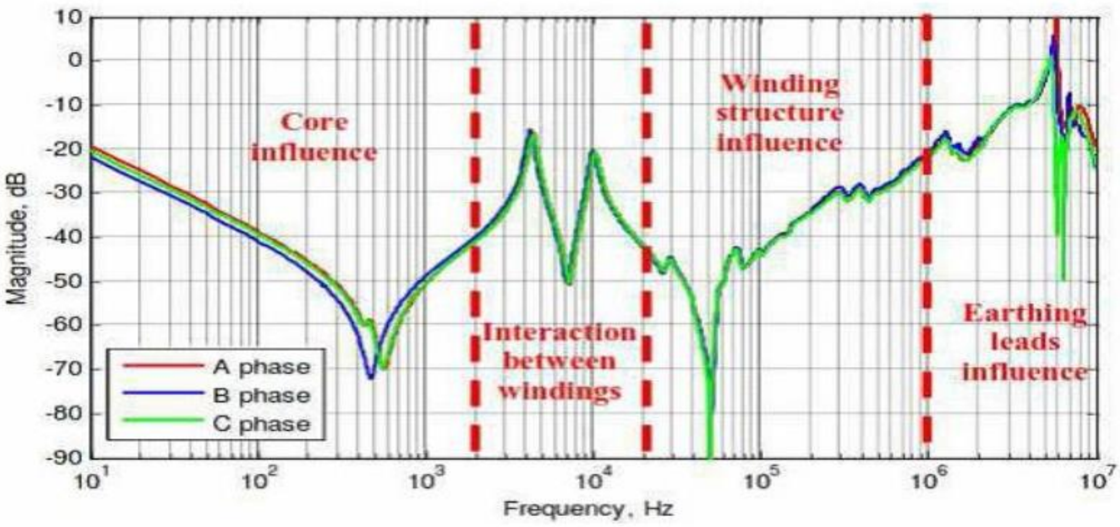

Figure 3. 19: Three phase output signal of SFRA [84]

These detected faults can be confirmed by other measurements, such as DC winding resistance, frequency response of stray losses (FRSL), short-circuit impedance / leakage reactance, exciting current, or transformer turns ratio (TTR) measurement. No other method is as sensitive to mechanical deformations of the active part of power transformers as SFRA. [67]

3.3.11 Leakage Reactance/Short Circuit Impedance Tests (IEC 60076-5):

The field leakage reactance test is an AC (60 or 50Hz) short-circuit impedance test, which is performed to detect mechanical winding movement and/or deformation within a power transformer.

The Leakage Reactance measurement directly corresponds to the leakage flux. Leakage flux is flux that does not link all the turns of the winding. It is normal that some of the flux escapes. This leakage flux also helps create impedance that is used to limit short circuit current. Leakage flux creates reactive magnetic energy that behaves like an inductor in series in the primary and secondary circuits. This impedance can be easily measured, analysed, and trended. This simple model is shown in Figure 3.20. Winding movement changes the reluctance of the leakage flux path, resulting in a change in the expected leakage reactance measurement. [85]

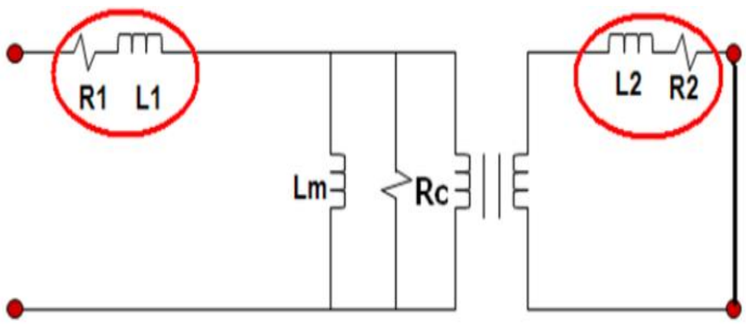

Figure 3. 20: Leakage Reactance Circuit Model

The leakage reactance test is one of our transformer diagnostic “fingerprint” measurements. There are two methods for performing Leakage Reactance tests, as follows:

a. Three Phase (3-Phase) Equivalent Test
b. Per-Phase Test

1ϕ UNIT $\rightarrow$ $$\%Z = \frac{1}{10}\left[(Z)\left(\frac{BasekVA_1}{kV^2}\right)\right]$$

3ϕ UNIT $\rightarrow$ $$\%Z = \frac{1}{60}\left[(Z_{AC} + Z_{BA} + Z_{CB})\left(\frac{BasekVA_3}{kV_{ll}^2}\right)\right]$$

Figure 3. 21: Leakage Reactance Equations [85]

3-Phase Equivalent Test: the purpose of the 3-Phase equivalent test is to produce a test result to compare to the factory short-circuit impedance percentage value (Z% nameplate), which can be found on the transformer nameplate. One disadvantage of the 3-Phase equivalent test (relative to the Per-Phase test) is that the measured percent impedance value (Z% measured) is comprised of all three phases of the transformer, which may result in overlooking (or “masking”) a mechanical failure isolated to one particular phase.

Another issue with the 3-Phase equivalent test is that, to compare the field and nameplate values, the transformer must be tested on the same tap-changer position(s) as the factory test. This is often problematic when the de-energized tap-changer has been moved off of the nominal position for service [85].

Test procedure:

• All three phases of secondary winding are electrically short circuited

• Single phase source excites two phases each in series

• Measurement is conducted on three groups of two phases

• Sum of three impedances and / or reactance is used to calculate final % impedance and / or % reactance which is then compared to nameplate or benchmark [86].

Table 3.9, shown below, provide the connections for the 3-Phase Equivalent test:

Table 3. 9: Connections for the 3 Phase Equivalent Test [85]

Test	Phase	Terminals	Ground	Short	Measure
1	LL-A	H1red-H3black	X0	X1,X2,X3	H1-H3
2	LL-B	H2red-H1black	X0	X1,X2,X3	H2-H1
3	LL-C	H3red-H2black	X0	X1,X2,X3	H3-H2

Per-Phase Test: the Per-Phase test is often more valuable to the overall transformer condition assessment (relative to the 3-Phase test) because the Per-Phase test isolates and tests each individual phase of the transformer. Therefore, if a mechanical failure exists within one particular phase of the transformer, it will usually be more obvious with the Per-Phase test.

One advantage of the Per-Phase test is that the measured impedance (Ω) values are not compared to the nameplate percent impedance (Z% nameplate) value, so the transformer does not have to be tested in the same tap-position(s) as the factory test. Another advantage of the Per-Phase test is that a baseline value is not required to perform a reliable condition assessment of the transformer (although it is helpful). If a mechanical failure exists within the main tank of the transformer, it will typically cause one or more of the Per-Phase measurements to be dissimilar from the others, which would then trigger further investigation. We recommend that the measured impedance (Ω) values of the three Per-Phase [85].

Test procedure:

• Single phase source performs individual test on each phase.

• Only corresponding phase on secondary winding is electrically short circuited

• Individual impedance and / or reactance are used to calculate individual % impedance and / or % reactance which is then compared among phases or benchmark [85].

Table 3.10, shown below, provide the connections for Per-Phase test:

Table 3. 10: Connections for the Per Phase Test [85]

Test	Phase	Terminals	Ground	Short	Measure
4	LL-A	H1red-H3black	X2, X3	X1 & X0	H1-H3
5	LL-B	H1red-H3black	X1, X3	X2 & X0	H2-H1
6	LL-C	H1red-H3black	X2, X1	X3 & X0	H3-H2

3.3.12 Turns Ratio Test (IEC 60076-1):

The Transformer Turns-Ratio (TTR) Test is a functional check of the transformer – The TTR Test helps determine whether or not the transformer can perform its intended function. If a transformer cannot transform the applied voltage with the correct ratio, then the unit should not be returned to service until the issue is resolved – “Do Your Job” [71].

The TTR measurement is used to detect the compromised insulation (turn-to-turn, inter-winding, and/or winding-to-ground insulation), core defects, tap-changer component faults (e.g. faults involving the regulating winding, reversing switch, tap selectors, stationary contacts, etc.), severe discontinuities, poor connections, and/or open-circuits and severe mechanical failures (e.g. winding movement or deformation). [72]

In the TTR test, the ratio needs to check at all taps position. The TTR can provide evidence of gross winding resistance deviation. A magnetized core or missing ground reference may influence the measurement and lead to incorrect results. Making sure the transformer core is demagnetized and proper grounds are established on each winding is therefore very important [67].

Test procedure:

Step 1: Open circuit the secondary-side bushing terminals

Step 2: Apply an AC voltage across one phase on the primary-side

Step 3: Measure the AC voltage induced across the same phase on the secondary-side

Step 4: Calculate the ratio **(**Vprimary/Vsecondary) and assess the results by comparing the measured ratio to the nameplate ratio and amongst the three phases [71]

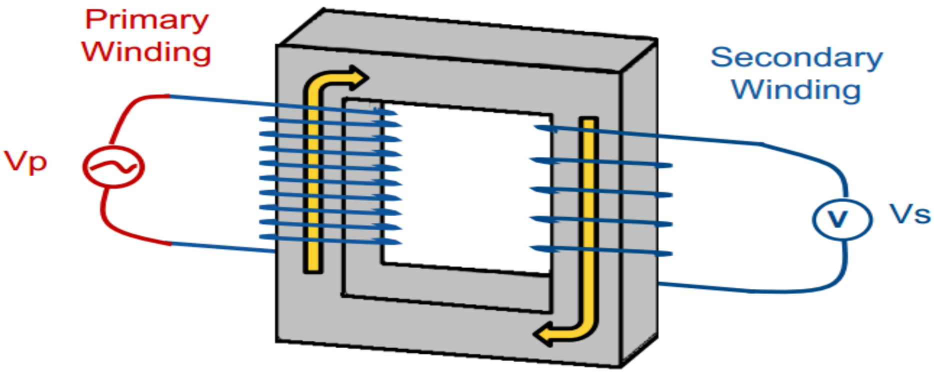

Figure 3. 22: Turn ratio test connection [71]

Results are compared with nameplate values and across phases. According to IEC 60076-1 a deviation of more than 0.5% is an indication of insulation failure, short circuit or open turns….etc. It is recommended to start the test at low voltage (100 volts) and verify the result against the nameplate value. If no significant deviation is found then it is safe to increase the voltage up to the rated voltage. This approach helps to avoid unwanted insulation breakdown [67].

These tests are performed with the transformer de-energized and may show the necessity for an internal inspection or removal from service. The TR is determined during Factory Acceptance Tests (FAT) and needs to be checked routinely once the transformer is in service.

3.3.13 Tap Changer Condition:

The load tap changer (LTC) of a transformer is used to regulate the voltage despite variations in the load. A range of insulating materials like oil, fiberglass, cardboard and proxy resin are used in a tap changer as its insulation. Failure to a tap changer can result into a catastrophic failure of nearby transformers. The authors of [49] and [88], respectively state that 30% and 40% of transformer failure results from the tap changer malfunction and this could varies depending on the tap changer types, manufacturer, operation and maintenance frequency. Unlike in the main tank, a certain amount of combustible gas in the tap changers is considered normal, which is produced from the operation of LTC. The trapping of gases is depending on the breathing system. A sealed LTC can trap most of the gases while gas is rapidly vents from a free breathing system [41]. However, insufficient adoption of standards and the lack of guidelines make it hard to assess the condition of LTC directly from DGA [88]. Consequently, a series of tests such as DGA, oil quality, contact resistances and acoustic signal are performed, at the same time the number of operations, temperature and motor current is monitored to assess the condition of tap changer and its insulation. Due to poor availability of DGA and oil analysis data, the construction type and the number of operation are used in this work to assess the condition of a tap changer. [84]

There are several diagnostic methods used today, that can be divided into:

1. Oil and insulation analysis
    - Dissolved gas analysis (DGA)
    - Oil quality analysis
2. Analysis of tap changer contacts
    - Static resistance measurement
    - Dynamic resistance measurement (DVtest)
3. Mechanical analysis
    - Motor current measurement [42]

3.4 Conclusion:

In this chapter, we represent the general concept of health index, and we summarise a review of the different condition monitoring and diagnostics tests of power transformer that we use in our health index model. These analytical and diagnostic techniques will help the maintenance engineers to interpret the test results and suggest the important parameters of transformers that need to be monitored.

Chapter IV:

Health Index Calculation

4.1 Introduction

Health index (HI) is a size which can be used to evaluate the general condition of a power transformer. This size is calculated using some of the most representative elements of diagnosis (or state) that characterize the operation and status of the transformer and is converted into a quantitative index that provides information about its health status [36].

4.2 Health Index Model:

4.2.1 Input:

The model does only take service and condition data as input in the evaluation of a transformer. The required data, as well as a schematic of how these are processed, can be seen in Figure 4.1.

4.2.2 Parameters of Health Index Formulation:

The following will explain how the different input parameters are converted to scores in the health index model. The modules for assessment of each condition parameter will be presented one at the time.

4.2.2.1 Dissolved gas analysis (DGA):

Table 4.1 presents the limit value of scoring and weighting factor for DGA of oil in main tank. The score is classified into six levels: one means good condition and six means poor. The lower number of weighting factor implies less important than upper number. The scoring and weighting factor are calculated to get percent DGA factor (DGAF) as written in Eq. (1) [37].

$$\text{DGAF}=\frac{\sum_1^7 Si*Wi}{\sum_1^7 Wi} \qquad (1)$$

Table 4. 1: Scoring and weight factors for gas levels [PPM].

Gas	Score (S_i)						W_i
	1	2	3	4	5	6	
H_2	≤100	100-200	200-300	300-500	500-700	≥700	2
CH_4	≤75	75-125	125-200	200-400	400-600	≥600	3
C_2H_6	≤65	65-80	80-100	100-120	120-150	≥150	3
C_2H_4	≤50	50-80	80-100	100-150	150-200	≥200	3
C_2H_2	≤3	3-7	7-35	35-50	50-80	≥80	5
CO	≤350	350-700	700-900	900-1100	1100-1400	≥1400	1
CO_2	≤2500	≤3000	≤4000	≤5000	≤7000	≥7000	1

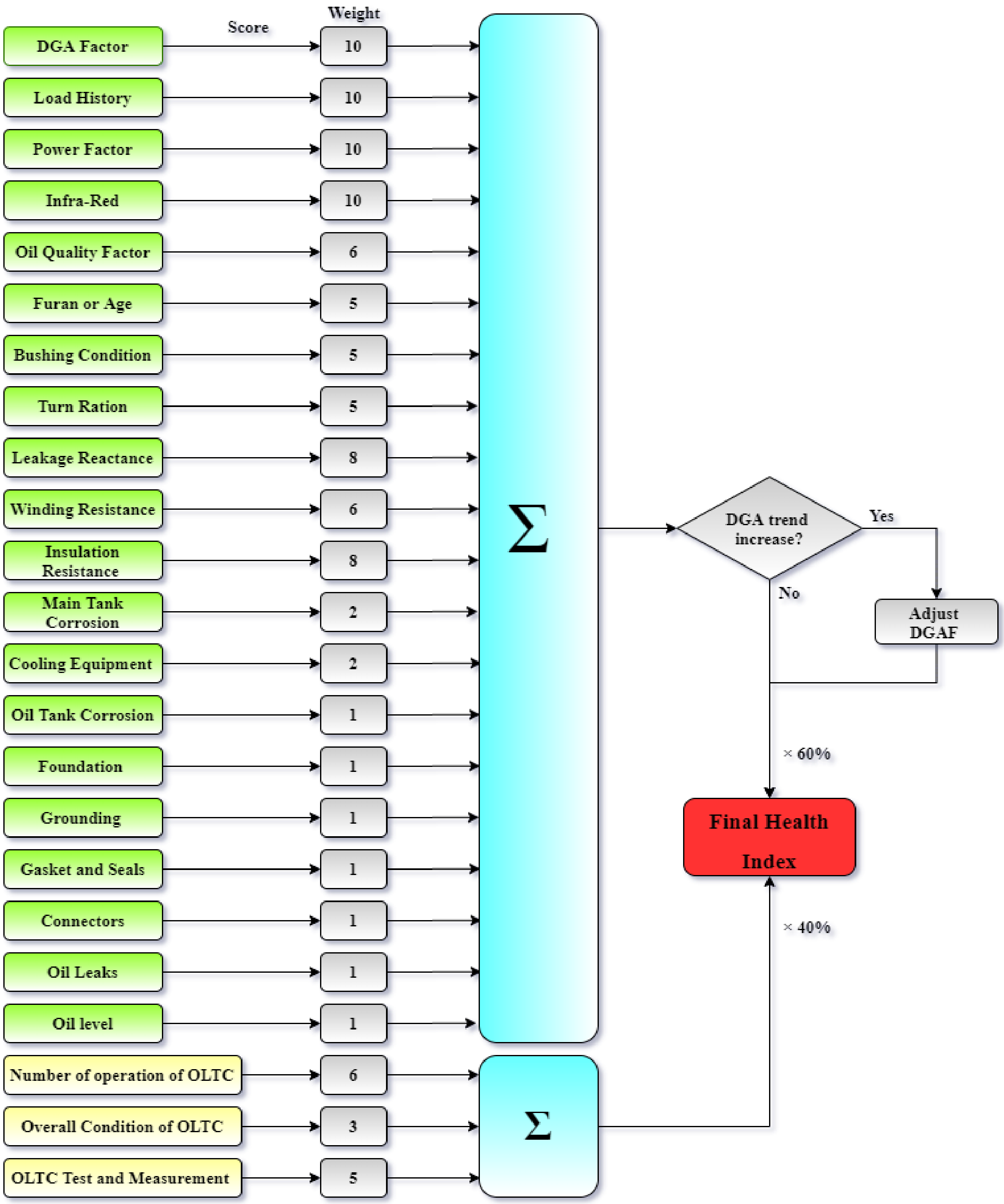

Figure 4. 1: Flowchart of the Health Index required input data and calculation procedure.

From the DGAF a rating is assigned according to Table 4.2.

Table 4. 2: Transformer rating based on DGA Factor.

Rating	**Condition**	**Description**
4	Good	DGAF<1.2
3	Acceptable	1.2≤DGAF<1.5
2	Need Caution	1.5≤DGAF<2
1	Poor	2≤DGAF<3
0	Very poor	DGAF≥ 3

4.2.2.2 Oil quality factor:

Oil quality testing is performed to check the general condition of insulating oil. The evaluation of oil quality is performed by considering six testing: dielectric Strength, interfacial tension (IFT), neutralization number (NN) or acidity, water content, color and dissipation factor (DF). Show in Table 4.3. The scoring and weighting factor are calculated to get percent oil quality factor (OQF) from Eq. (2), [37]

$$\text{OQF}=\frac{\sum_1^6 Si*Wi}{\sum_1^6 Wi} \qquad (2)$$

Table 4. 3: Scoring and weight factors for oil quality parameters.

	U ≤ 60 kV	**60 kV < U < 230 kV**	**230 kV ≤ U**	**Score (Si)**	**Weight (Wi)**
Dielectric Strength [kV] (2 mm gap)	≥45	≥52	≥60	1	3
	35–45	47–52	50–60	2	
	30–35	35–47	40–50	3	
	≤30	≤35	≤40	4	
IFT dyne/cm	≥25	≥30	≥32	1	2
	20–25	23–30	25–32	2	
	15–20	18–23	20–25	3	
	≤15	≤18	≤20	4	
Acid Number [mg KOH/g]	≤0.05	≤0.04	≤0.03	1	1
	05–0.1	0.04–1.0	0.03–.07	2	
	0.1–0.2	1.0–0.15	0.07–.10	3	
	≥0.2	≥0.15	≥0.10	4	
Water Content (ppm)	≤30	≤20	≤15	1	4
	30–35	20–25	15–20	2	
	35–40	25–30	20–25	3	
	≥40	≥30	≥25	4	
Color	≤1.5			1	2
	1.5–2.0			2	
	2.0–2.5			3	
	≥2.5			4	
Dissipation Factor (%) 90 °C	≤0.1			1	3
	0.1–0.5			2	
	0.5–1.0			3	
	≥1.0			4	

From the OQF a rating is assigned according to Table 4.4.

Table 4. 4: Transformer rating based on OQ Factor

Rating	**Condition**	**Description**
4	Good	OQF < 1
3	Acceptable	1 ≤ OQF < 1.6
2	Need Caution	1.6 ≤ OQF < 2.4
1	Poor	2.4 ≤ OQF < 3.2
0	Very poor	OQF ≥ 3.2

4.2.2.3 Load history factor:

Practically, recorded monthly load peaks can be employed to contribute load history to the HI calculation. The load history is categorized according to the five groups listed below:

N_0: Number of $^{SI}/_{SB}$ that are lower than 0.6, I=0

N_1: Number of $^{SI}/_{SB}$ that are between 0.6 and 1, I=1

N_2: Number of $^{SI}/_{SB}$ that are between 1 and 1.3, I=2

N_3: Number of $^{SI}/_{SB}$ that are between 1.3 and 1.5, I=3

N_4: Number of $^{SI}/_{SB}$ that are bigger than 1.5, I=4

Where **Si** is the monthly peak load and **S_B** is the rated loading of the transformer.

Eq. (3) proposes a linear method of load score calculation and Table 4.5 describes a ranking method of transformer condition using the load history data I is an integer 0 to 4 [69].

$$LF=\frac{\sum_0^4 (4-i)*Ni}{\sum_0^4 Ni} \qquad (3)$$

Table 4. 5: Load factor rating

Rating	Load factor	Condition
4	LF ≥ 3.5	Good
3	2.5 ≤ LF < 3.5	Acceptable
2	1.5 ≤ LF < 2.5	Need Caution
1	0.5 ≤ LF < 1.5	Poor
0	LF ≤ 0.5	Very poor

4.2.2.4 Power Factor

Power factor measurements are an important source of data to monitor transformer and bushing conditions. Measurement of a transformer insulation's capacitance and power factor at voltages up to 10 kV (at 50 or 60 Hz) has long been used as both a routine test and for diagnostic purposes we have to be [38]:

a. Overall power factor

Table 4.6 recommends a ranking method for the power factor of the transformer. PFmax is the greatest of all the measured power factors:

Table 4. 6: Transformer power factor rating [69].

Rating	Maximum Power factor [%]	Condition
4	$PF_{max} < 0.5$	Good
3	$0.5 \leq PF_{max} < 0.7$	Acceptable
2	$0.7 \leq PF_{max} < 1.0$	Need Caution
1	$1.0 \leq PF_{max} < 2.0$	Poor
0	$PF_{max} \geq 2.0$	Very poor

b. Bushing power factor

General guidelines for evaluating the **C1** and **C2** capacitance data are as follows:

Table 4. 7: Bushing power factor rating [39].

Rating	Difference between measurement and nameplate	Bushing condition
4	+/-3%	Very good bushing
3	+/-3% to +/-5%	Good bushing
2	+/-5% to +/-8%	monitor bushing closely
1	+/-8% to +/-10%	Poor bushing
0	+/-10% or greater	replace bushing

4.2.2.5 Furanic analysis

The analysis of furan is especially the decaying of paper insulation in transformer oil. This test is additionally performed, which the transformer has a high level of carbon monoxide and carbon dioxide, which cause overheat problem. Furan is a method to determine the condition of paper insulation inside transformer. Measuring the furfural content of the oil pays attention to 2-furaldehyde (2-FAL) presented, limit are indicated in Table 4.8. [37]

Table 4. 8: Furfural concentration test rating or age rating where test results are not available.

Rating	Furans content [ppm]	Transformer life [years]
4	0 – 0.1	< 20
3	0.1 – 0.25	20 – 40
2	0.25 – 0.5	40 – 60
1	0.5 – 1.0	> 60
0	> 1.0	…

4.2.2.6 Infra-red thermography:

The temperature comparisons shown in Table 4.9 between similar components under similar loading and temperature rises above ambient have been found to be practical during IR inspection according to Table 4.9, Thermographic Survey Suggested Actions Based on Temperature Rise [84].

Table 4. 9: Heating severity classification

Rating	Increased temperature [IT] °C	Description
4	IT < 9	Good
3	10 ≤ IT < 20	Acceptable
2	20 ≤ IT < 30	Need Caution
1	30 ≤ IT < 49	Poor
0	IT ≥ 49	Very poor

4.2.2.7 Electrical Test

The rest of the electrical tests involved in the HI calculation are summarized in Table 4.10, with their rating factors. Turn ratio test, excitation current test, leakage reactance test, insulation resistance, sweep frequency response analysis and winding resistance test are mainly considered as diagnostic tests rather than routine tests, and the related test data may not be available. [88]

Table 4. 10: Ranking of the Turn Ratio, Leakage Reactance, insulation resistance, and Winding Resistance Test

Rating Code	Turn ratio (TR) deviation [%]	Leakage reactance deviation [%]	Winding resistance deviation [%]	Insulation resistance[MΩ]
4	ΔTR ≤ 0.1%	ΔX < 0.5%	ΔR < 1%	R > 1000
3	0.1% < ΔTR ≤0.5%	0.5% ≤ ΔX < 1%	1% ≤ ΔR<2%	100 ≤ R < 1000
2	0.5% < ΔTR ≤ 1%	1% ≤ ΔX < 2%	2% ≤ ΔR <3%	10 ≤ R < 100
1	1% < ΔTR < 2%	2% ≤ ΔX < 3%	3% ≤ ΔR<5%	1 ≤ R < 10
0	ΔTR ≥ 2%	ΔX ≥ 5%	ΔR ≥ 5%	R < 1

4.2.2.8 SFRA test

This test take a place when there is a missing data in the leakage reactance test:

Table 4. 11: *SFRA factor rating*

Rating	SFRA (SC: Shape Changes) [dB]	Condition
4	<1	Good
3	1 ≤ SC <1.5	Acceptable
2	1.5 ≤ SC<2	Need Caution
1	2 ≤ SC <3	Poor
0	SC ≥3.	Very poor

4.2.2.9Maintenance History:

The impact of the maintenance history of an asset is evaluated based on the number of corrective maintenance work orders during the last five years. Such work orders for the different components on the transformer are counted and compared to the scoring criteria in Table 4.12. [3]

Table 4. 12: Individual component rating criteria based on number of corrective maintenance work orders.

Rating Code	Bushings	Oil leaks	Oil level	Cooling	Main tank	Oil tank	Foundation	Grounding	Gaskets	Connectors
4	0	0-2	0	0-3	0	0	0	0	0	0
3	1-2	3-4	1-2	4-6	1-2	1-2	1-2	1-2	1-2	1-2
2	3-4	5-6	3-4	7-10	3-4	3-4	3-4	3	3-4	3
1	5-7	7-8	5-6	11-15	5	5-6	5	4-6	5-6	4
0	>7	>8	>6	>15	>5	>6	>5	>6	>6	>4

4.2.2.10 Tap Changer:

Depending on the construction, the insulation system of an LTC usually consists of oil, cardboard, fiberglass, or epoxy resin. There are several types of measurements for assessing the condition of LTCs such as: number of operations, DGA, oil quality, contact resistance, temperature, motor current, acoustic signal, relay timing, maintenance data, and the history of the LTC [88].

The main factors employed for HI calculation are the number of operation (store the number of operation), contact resistances and oil quality.

a. Number of Operation of OLTC:

Table 4. 13: rating of OLTC based on number of operation

Rating code	Number of operation (NO) of OLTC for transformer rating < 220 kV	Number of operation (NO) of OLTC for transformer rating > 220 kV	Condition
4	NO <15,000 since the last oil change **And** Number of oil changes since the last service = 0	NO <5000 since the last oil change **And** Number of oil changes since the last switch revision = 0	Very Good
3	15,000 < NO < 20,000 since the last oil change **And** Number of oil changes since the last service = 1	5,000 < NO < 10,000 since the last oil change **And** Number of oil changes since the last switch revision = 1	Good
2	20,000 < NO < 25,000 since the last oil change **And** Number of oil changes since the last service = 2	10,000 < NO < 15,000 since the last oil change **And** Number of oil changes since the last switch revision = 2	Fair

1	25,000 < NO < 30,000 since the last oil change **And** Number of oil changes since the last service = 3	15,000 < NO < 20,000 since the last oil change **And** Number of oil changes since the last switch revision = 3	Poor
0	30,000 < NO < 35,000 since the last oil change operations **And** Number of oil changes since the last revision = 4 and more	20,000 < NO < 25,000 since the last oil change **And** Number of oil changes since the last revision of the switch = 4 and more	Very poor

b. OLTC test and measurement:

Power transformer OLTCs need close monitoring of their condition due to their high failure rate. Typical switching times of the diverter or selector switch between 40 and 60ms make it difficult to detect any effects during the switching process using a conventional static winding resistance measurement, which might take a few minutes. Therefore the principal of the Dynamic Contact Resistance DRM was developed as a supplementary diagnostic method for this specific use.

4.2.3 Output

A quantified scoring system can be used to appropriately represent the transformer health. This involves the following steps:

1. "Deterioration" assessments or scores are converted to health scores in a defined range from "perfect health" to "very poor condition."
2. Importance weighting is assigned to each factor in a range from "modest importance" to "very high importance."
3. General deterioration index is formulated by calculating the maximum possible score by summing the multiples of steps 1 and 2 for each factor.
4. The general deterioration index is normalized to a maximum score of 100 based on having a defined acceptable/ minimum number of condition criteria available.
5. The dominant factors are normalized to a maximum score of 100.

A calculation of the overall Health Index is performed, where 100% represents excellent health and less than 30% represents "poor" health. Table 4.14 provide a summary of the scoring system of the main condition parameters that are used in this study for condition assessment. Totalled scores are used in calculating final HI.

For each component, the HI calculation involves dividing its total condition score by its maximum condition score, then multiplying by 100. This step normalizes scores by producing a number from 0 (completely degraded transformer) to 100 (perfect condition). The power transformer is rated against a set of criteria for each condition parameter. Considering all the discussed parameters and factors, the total HI of a power transformer is proposed as [88]:

$$\mathrm{HI} = X\% \times \frac{\sum_{j=1}^{n} Kj\, Sj}{\sum_{j=1}^{n} 4Kj} + Y\% \times \frac{\sum_{j=n+1}^{z} Kj\, Sj}{\sum_{j=n+1}^{z} 4Kj}$$

Where:

Sj: Score corresponding to parameter “j”

Kj: “Weighing factor” corresponding to parameter “j”

J: Number of each diagnostic parameter

With X (%) +Y (%) = 100 (%). [40]

$$\Rightarrow \mathbf{HI = 60\% \times \frac{\sum_{j=1}^{21} Kj * HIFj}{\sum_{j=1}^{21} 4 * Kj} + 40\% \times \frac{\sum_{j=22}^{24} Kj * HIFj}{\sum_{j=22}^{24} 4 * Kj}}$$

Kj and HIF*j* are introduced in Table 4.14 weighting factor of 40% is assigned to the LTC and 60% to the transformer. This is based on an international survey done by a CIGRÉ working group on failures in large power transformers that found that about 40% of failures were due to LTC. [88]

Table 4. 14: Health Index Scoring.

	Transformer Condition Criteria	**K**	**HIF**
1	DGA	10	4,3,2,1,0
2	Load History	10	4,3,2,1,0
3	Power Factor	10	4,3,2,1,0
4	Infra-Red	10	4,3,2,1,0
5	Oil Quality	6	4,3,2,1,0
6	Furan or Age	5	4,3,2,1,0
7	Turns ratio	5	4,3,2,1,0
8	Leakage reactance	8	4,3,2,1,0
9	Winding resistance	6	4,3,2,1,0
10	Insulation resistance	6	4,3,2,1,0

12	Bushing Condition	5	4,3,2,1,0
13	Main Tank Corrosion	2	4,3,2,1,0
14	Cooling Equipment	2	4,3,2,1,0
15	Oil Tank Corrosion	1	4,3,2,1,0
16	Foundation	1	4,3,2,1,0
17	Grounding	1	4,3,2,1,0
18	Gaskets, seals	1	4,3,2,1,0
19	Connectors	1	4,3,2,1,0
20	Oil Leaks	1	4,3,2,1,0
21	Oil Level	1	4,3,2,1,0
22	Number of Operation of OLTC	6	4,3,2,1,0
23	Overall condition of OLTC	3	4,3,2,1,0
24	OLTC test and measurement	5	4,3,2,1,0

Finally, Table 4.15 provides categories of HI results and correlates these to an expected lifetime and required action. HI values are grouped into discrete categories from "very good" To "very poor." This aggregation into discrete categories for a condition index requires fine-tuning of the health scoring system, because it is necessary that the relative degree of severity of the scores due to "dominant" factors and those due to generalized degradation align at the boundaries between each category. This may require iteration of the individual steps to ensure that the resulting index is rational and coherent and reasonably reflects field conditions.

Table 4. 15: Health Index and Transformer Expected Lifetime

Health index	**Description**	**Expected Lifetime**	**Condition**
100-85	Some aging or minor deterioration of a limited number of components	More than 15 years	Very Good
85-70	Significant deterioration of some components	More than 10 years	Good
70-50	Widespread significant deterioration or serious deterioration of specific components	Up to 10 years	Fair
50-30	Widespread serious deterioration	Less than 3 years	Poor
30- 0	Extensive serious deterioration	At End-of-Life	Very Poor

4.3 PTA Software

The entire concept of health indexing is dependent on the availability of condition data and it is thus reasonable to discuss the data requirements of the models in question. As previously stated, it is important that the required data is available for a majority of the assets in a fleet for them to be compared on the same grounds and for the model to be useful. On the other hand it is important that the input data contains information with strong relevance for the asset condition. One of the issues to assess the condition of power transformers in Algeria is the lack of the results of the diagnostics tests (unavailable or lost data). "How to solve this issue?"

The module above is implemented by using our program software which name's PTA (Power Transformer Assessment). This software programming by using Python 3.8, PYQT5 package and Qt designer.

PTA software have several advantages, which are:

- It can easily record the data.
- It can easily classify the transformers according to their conditions.
- The user can easily read the information that needs.
- Facilitates calculations.
- The Security (Password).

The PTA software divided into four parts:

1. "Transformer Park" which contain three tabs: the nameplate, references tests and historical tests of each transformer from different region, services and posts. Figure 4.2 shows the transformer park part of PTA software.

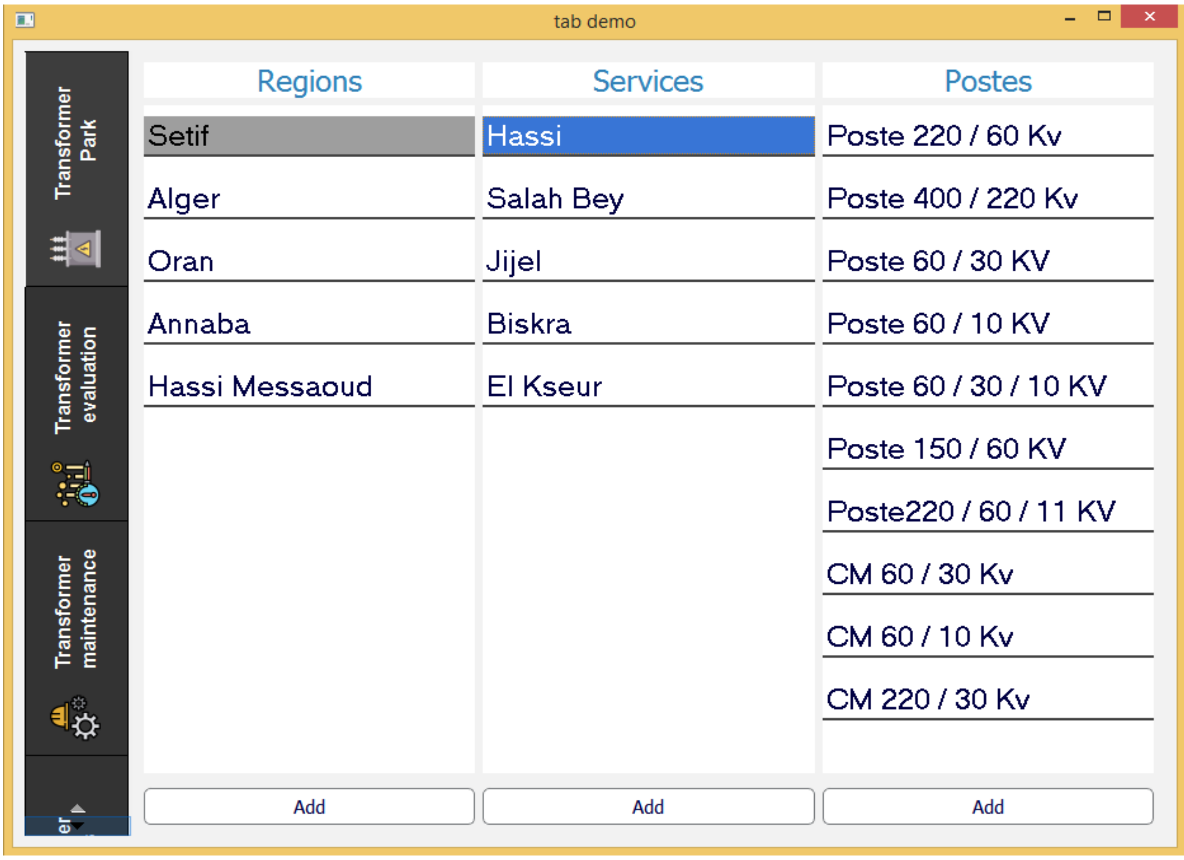

Figure 4. 2: PTA park transformer

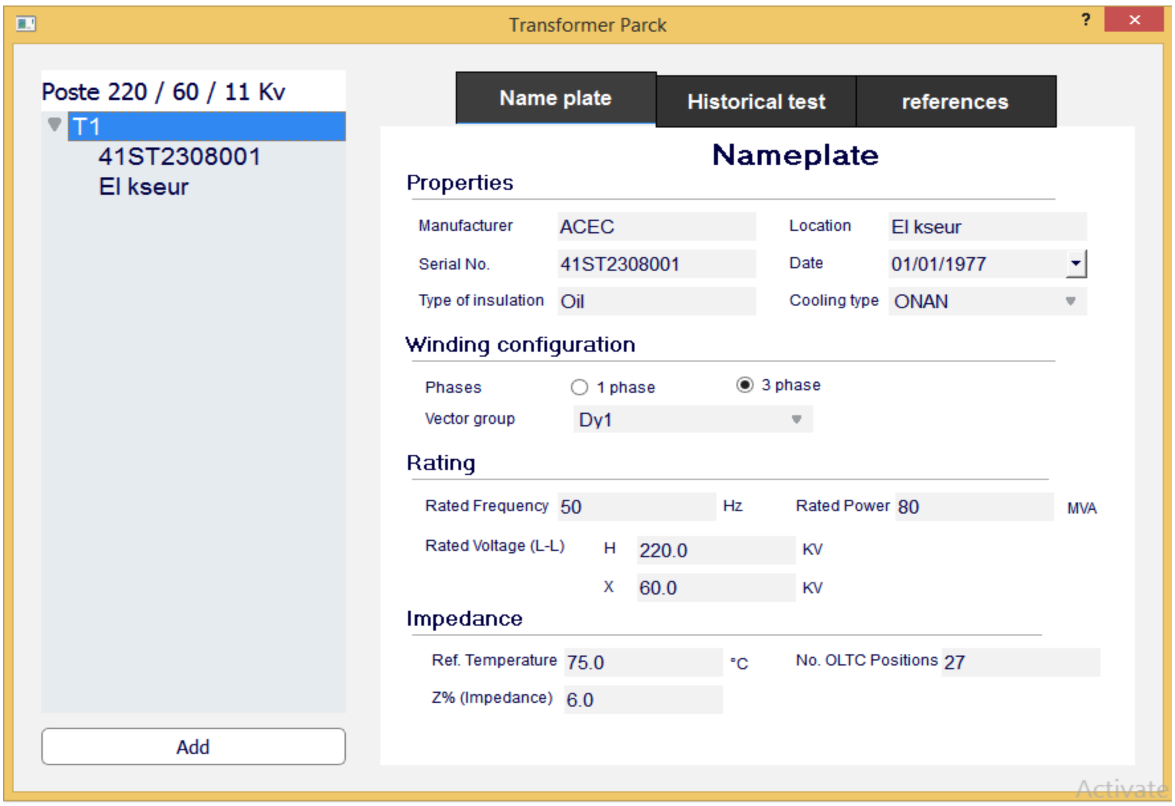

Figure 4. 3F: Name plate tap in Transformer Park

2. "Evaluation of transformers" which contain two tabs: first tab use to calculate the health index score of each parameter and the total health index, and the second tab use to classify the transformers according to their final health indices. Figure 4.4 shows the Evaluation of transformers part of PTA software.

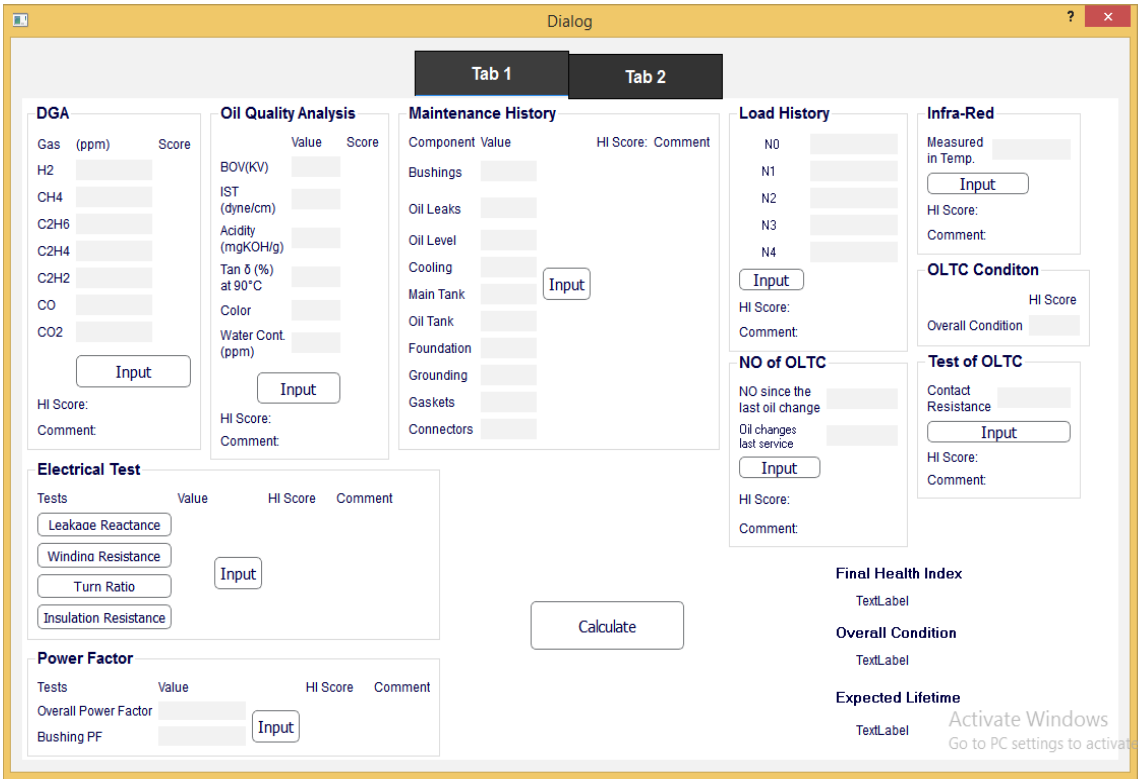

Figure 4. 4: PTA window for transformer evaluation

3. "Transformer Maintenance"
4. "Transformer Exploitation"

4.4 Results

To test its performance, the proposed model has been applied to six Algerian power transformers. The output of the model on parameter level and transformer level will further be presented. The data used in the health index calculation for the selected transformers are given in Appendix C.

4.4.1 The Transformers Data

The transformers evaluated by the proposed model are shown in Table 4.16. These transformers were selected in order to investigate how the model would perform for units of different condition, age and geographic location.

Table 4. 16: Age, nameplate data and expected condition for the transformers used to test the proposed health index model.

Transformer	**Age**	**Voltage [kV]**	**Power [MVA]**
T1- VIJAI	4	60/30	40
T2- BOUSSAADA	15	60/31,5	40
T3- MSILLA	41	220/60/11	120
T4- EL-KSEUR	43	220/60/11	80
T5-OUED ATHEMENIA	48	220/60/11	120

4.4.2 Results

In this section, the results from each of the parameters are shown for each of the six transformers investigated. Results both on module level and transformer level are shown. Module scores are given in Table 4.17. The final health index scores of the six transformers are shown in Table 4.18. For comparison, the expected condition and the age of the transformers are also shown in this table.

Table 4.17: Results from the different parameters of the health index model for each of the five transformers. A score of 4 represents the best condition and 0 the worst.

Parameters	**T1**	**T2**	**T3**	**T4**	**T5**
DGAF	4	4	2	2	1
LF	3	3	3	2	3
PF	4	3	1	0	2
Infra-Red	4	4	3	3	1
OQF	4	4	2	1	1
Furan	4	4	1	2	1
Turns ratio	4	3	3	3	2
Leakage reactance	4	4	4	4	2
Winding resistance	4	3	4	4	3
Insulation resistance	4	4	3	2	2
Bushing Condition	3	3	2	1	2
Main Tank Corrosion	4	4	2	3	2
Cooling Equipment	4	4	4	4	3
Oil Tank Corrosion	4	4	2	3	3
Foundation	4	4	3	4	4
Grounding	4	4	4	4	4
Gaskets, seals	4	4	1	3	2
Connectors	4	4	2	3	3

Oil Leaks	4	4	0	3	3
Oil Level	4	4	3	4	4
Number of Operation of OLTC	4	3	4	3	3
Overall condition of OLTC	4	3	2	3	0
OLTC tests and measurements	4	4	3	3	0

Table 4. 17: Age, expected condition and health index score for the transformers used to test the proposed health index model.

Transformer	Age	Health index score%	Expected Lifetime	Expected condition
T1	4	97.33	More than 15 years	Very good
T2	15	87.43	More than 15 years	Very good
T3	41	69.81	Up to 10 years	Fair
T4	43	64.78	Up to 10 years	Fair
T5	48	42.17	Less than 3 years	Poor

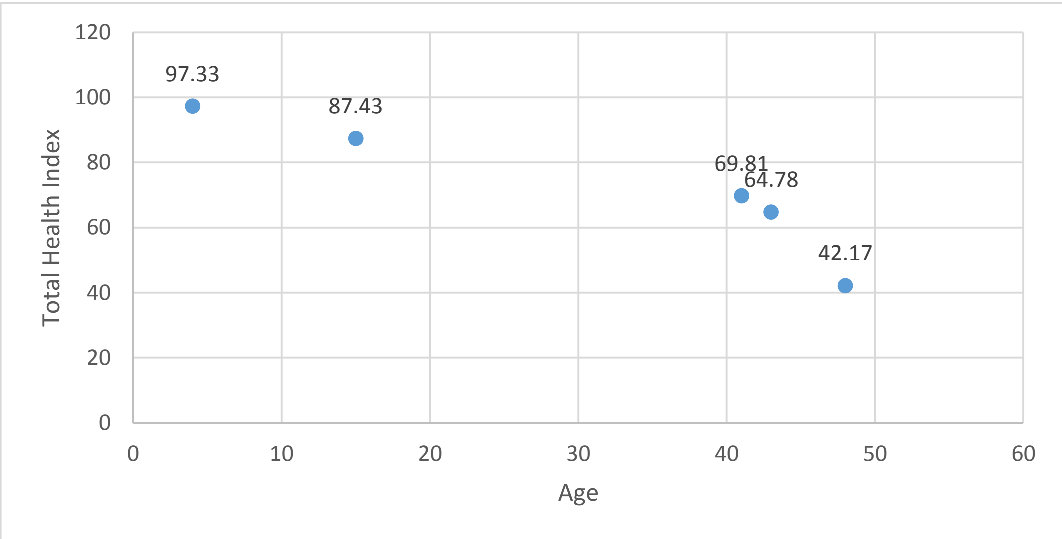

Figure 4. 5: Plot of the relationship between age and health index score of each asset.

4.4.3 Discussion:

The model proposed in this thesis is a first draft of a health index customized to Algerian needs. For this reason, the data collection practices of Algerian utilities have been essential to the design of the model. An important question is, however, whether or not the model is reliable enough for asset owners to put trust in it. In an attempt to answer this question, the above result aspects will be taken into account.

To facilitate the comparison, Table 4.17 shows five power transformers at different condition and age. From Table 4.18 and Table 4.17, T1 which is the new one whose health conditions are very good because the initial stage of working is tending to zero failure. This is a common outcome of the transformers health index since all the measurements and tests are at a very good scores.

For T2 transformer which has 15 years, the health condition of this transformer tends to be very good (87%) with teeny degradation in insulation and some maintenance like change oil or cleaning the bushing.

T3 and T4 transformers, the health condition is classified as acceptable condition (35%, 37% respectively) which means that these transformers can steel in service up to 10 years but with a serious series of a short term diagnostics (each 6 month or less) on each part of transformer (specially for insulations).

For T5 transformer which is the worst one in the group, the health condition is classified in the end of his life since all the factors are in the very poor condition (1 or 2 scores) especially for the OLTC which represents 40% of the overall health index condition. This means that the manager must be prepared to invest in a new transformer.

From the results presented above and since the model take all the aspects of the power transformer such as solid and liquid insulations , tap changer, bushing, winding and all other components, it appears that this model of health index is able to provide reliable scores for ranking of assets. Additionally, a decent relationship between the actual condition of an asset and the health index score appears to exist. It might therefore be said that the health index score is indicative of the condition of a transformer.

Also when it comes to the usability of the proposed model, it is believed that most asset managers will have access to the required input data. This is expected to be a large advantage since this allows all assets of a fleet to be assessed and since it minimizes the effort associated with such assessments. Additionally, the model is able to select appropriate values based on IEC standard (used in Algeria) values for some of the quantities that are in frequent use. This functionality is believed to be very important in order to make the health index an easy-to-use tool.

By making sure that every asset is evaluated by the same criteria, a ranking of assets by condition is made possible. This ranking will allow asset managers to see where maintenance or reinvestment is required simply by comparing the scores of the assets in a fleet.

4.5 Conclusion

In this chapter, we described a realistic Health Index method for power transformers using available data of a five power transformer and considering IEC recommendations for condition parameters. The calculation is based on weighting factors, condition ratings, and assigned scores for any specific parameter. By using a multi-criteria analysis approach, the various factors are combined into a condition-based Health Index. And also we use PTA program software to implement our model.

General Conclusion and Further Work

General Conclusion

In this thesis, a model for health indexing of power transformers is proposed. This model is based on identification of the most important failure modes and aging mechanisms for power transformers. Customizing the model to Algerian needs has been an important goal and the model has therefore been designed with special emphasis on the data availability faced by most Algerian utilities. This is important to ensure that all transformers are evaluated on the same basis. The model input data have for this reason been limited and special measurements that are not conducted regularly in Algeria have been left out. Based on the available input data, appropriate assessment models have been found. These have been designed corresponding to international standards on transformer maintenance. The output of the model is given as an overall score which describes the condition of the transformer.

The proposed model has been tested on five power transformers of various age and condition. This test showed that the model was able to differentiate between transformers in different conditions depending on the results of operating observations, field inspections, and site and laboratory testing into an objective and quantitative index. Furthermore, asset health index is a powerful tool for managing assets and identifying investment needs as well as prioritizing investments in capital and maintenance programs.

Further Work

Used the HI to estimate the probability of failure of the transformer in its present condition. Each transformer has a level of remaining strength, both electrical and mechanical, that decreases as its condition deteriorates with age and use. The transformer’s probability of failure depends on whether the stresses in the field exceed the remaining strength. The probability of the stress exceeding the strength is the probability of failure.

Furthermore, the methodology in this work can be applied to other equipments in the power system (High Voltage assets like: generators, motors, circuit breakers…etc.) for better efficiency and reliability of electric power system.

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Appendices

A | Excitation current test

A transformer's "exciting current" is essentially the minimum current required to operate the transformer under no-load conditions. The exciting current test is performed by applying an AC voltage on the primary winding of the transformer, while the secondary windings of the transformer are open-circuited. The current flowing through the primary winding of the transformer is then measured, and is the main focus of the exciting current measurement.

The purpose of any electrical diagnostic test is to detect a failure within the test specimen. The exciting current test is used to detect the compromised insulation (e.g. turn-to-turn, inter-winding, and/or winding-to-ground insulation), core failures, tap-changer failures (e.g. failures involving the regulating winding, preventative autotransformer, reversing switch, tap selectors, stationary contacts, etc.), severe discontinuities, poor connections and/or open-circuits.

If the test set "trips" when the exciting current measurement is performed, the user must troubleshoot the measurement to determine if the cause of the "overcurrent" is due to: user error (e.g. incorrect test connection), the transformer construction or a failure within the transformer.

Test Connections and Test Procedure

To properly understand, perform, and assess the exciting current measurement, it is important to become familiar with the recommended test connections for testing several different transformer winding configurations that are: delta, wye with an accessible neutral and wye without an accessible neutral.

Delta Primary Winding

Understanding, performing, and analysing the exciting current measurement for a transformer that has a Delta primary winding can be difficult, due to the test procedure required to isolate and measure each individual phase-winding of the transformer.

Consider the Phase-A measurement. Since the exciting current test is an open-circuit test, the three phase bushing terminals on the secondary (i.e. X1, X2, and X3) are open-circuited when the three exciting current measurements are performed. The high-voltage (HV) test lead is placed on the H1 bushing terminal and the low voltage (LV) test lead is placed on the H3 bushing terminal.

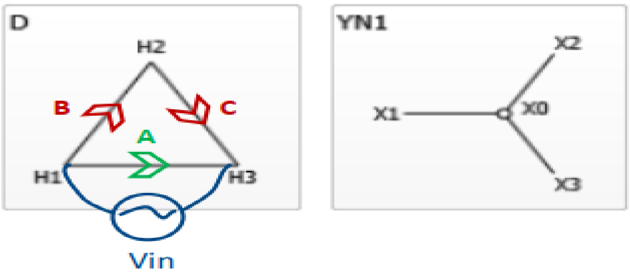

Figure A.1: *Phase-A Measurement - H2 Floating*

As can be seen in Figure 2, by leaving the H2 bushing terminal floating during the Phase-A exciting current measurement, the measured current will be comprised of all three phases. The goal of any electrical diagnostic test is to isolate the test specimen into as many components as possible, so to isolate each individual phase, a ground lead must be placed on the third, unused Delta bushing terminal. The ground connection will help remove the parallel phase-currents for the single phase-measurement.

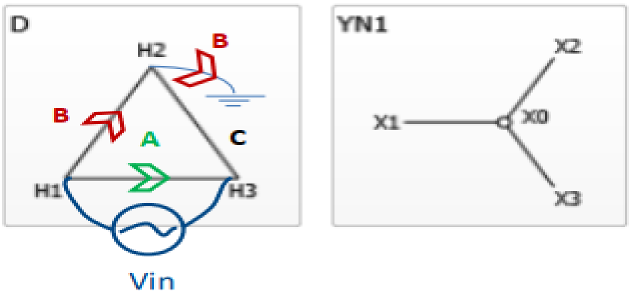

Figure A.2: *Phase-A Measurement - H2 Grounded*

As can be seen in Figure 3, when the test voltage is applied across the Phase-A winding (H1- H3), a current is induced in the Phase-A winding. However, the Phase-B winding current is directed to ground via the H2 ground connection. Since the exciting current measurement is an Ungrounded Specimen Test (UST), any current flowing to ground is “guarded” and removed from the measurement.

Table A.1 provides a summary of the phase-windings that are “excited” and measured when the exciting current test is performed on a transformer with a Delta primary winding.

Table A.1: *Delta Primary Winding – Measurement Summary*

	Test connection	**Ground**	**Exited phases**	**Measured phase**
Phase A	H1-H3	H2	Phase A and Phase B	Phase A
Phase B	H2-H1	H3	Phase B and Phase C	Phase B
Phase C	H3-H2	H1	Phase C and Phase A	Phase C

Wye Primary Winding with Accessible Neutral

The recommended test connections for testing a transformer with a Wye primary winding with an accessible neutral (H0) are discussed in this section. Fortunately, when the transformer under test has this particular winding configuration, the exciting current measurement is relatively simple to understand and perform.

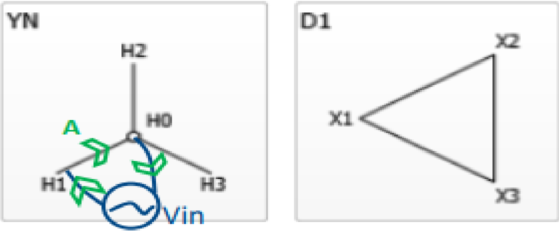

Figure A.3: *Ynd1 - Phase-A Exciting Current Measurement*

The recommended test connections for performing the exciting current measurement on aYnd1transformer are provided in Table A.2. For all three phase-measurements, the LV measurement lead is placed on the primary neutral bushing terminal (H0). Additionally, the HV injection lead is placed on one of the three primary phase bushing terminals (i.e. H1, H2, or H3) for each phase measurement.

Table A.2: *Ynd1 - Exciting Current Test Connections*

	High-voltage lead (LV)	**Low-voltage lead (LV)**	**ground**	**Float**	**Mode**
Phase A	H1	H0	-	X1,X2,X3,H2,H3	UST
Phase B	H2	H0	-	X1,X2,X3,H1,H3	UST
Phase C	H3	H0	-	X1,X2,X3,H1,H2	UST

Wye Primary Winding without Accessible Neutral

The recommended test connections for testing a transformer with a Wye primary winding without an accessible neutral (H0) are discussed in this section. Unfortunately, when the transformer under test has this particular winding configuration, the analysis of the exciting current measurement is somewhat complex.

When the Wye primary winding has no accessible neutral, there is no reasonable way to isolate and measure each phase-winding individually. Unfortunately, the LV measurement lead must be placed on one of the three phase bushing terminals, which results in "exciting" and measuring two phase-windings simultaneously.

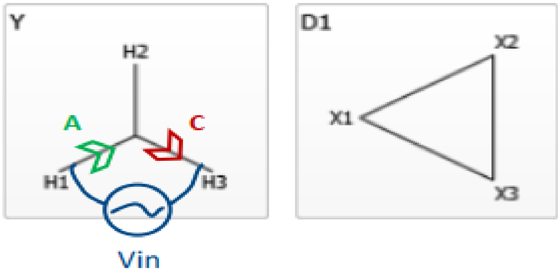

Figure A.4: *Yd1 "Phase-A" Exciting Current Measurement*

Consider the “Phase-A” measurement, which is depicted in Figure A.4. The HV injection lead is placed on the H1 bushing terminal and the LV measurement lead is placed on the H3 bushing terminal. As a result, the measured current for “Phase A” is actually the sum of the Phase-A and Phase-C winding currents. In other words, the Phase-A and Phase-C windings are tested in series.

A summary of the “excited” and measured phases for the three exciting current measurements is provided in Table A.3.

Table A.3: *Wye Primary Winding with No Accessible Neutral - Measurement Summary*

	Test connection	**Exited phases**	**Measured phase**
Phase A	H1-H3	Phase A and Phase C	Phase A and Phase C
Phase B	H2-H1	Phase B and Phase A	Phase B and Phase A
Phase C	H3-H2	Phase C and Phase B	Phase C and Phase B

Exciting Current Tap-Changer Patterns

The transformer exciting current measurement can be performed on various de-energized tap changer (DETC) and load tap-changer (LTC) positions to verify the integrity of the tap-changer and its associated components. To properly identify tap-changer failures using the exciting current measurement, it is important to understand the tap-changer patterns that can be obtained when performing the exciting current measurement on various tap-positions, which include,

1.) De-Energized Tap Changer (aka No-Load Tap-Changer) Patterns

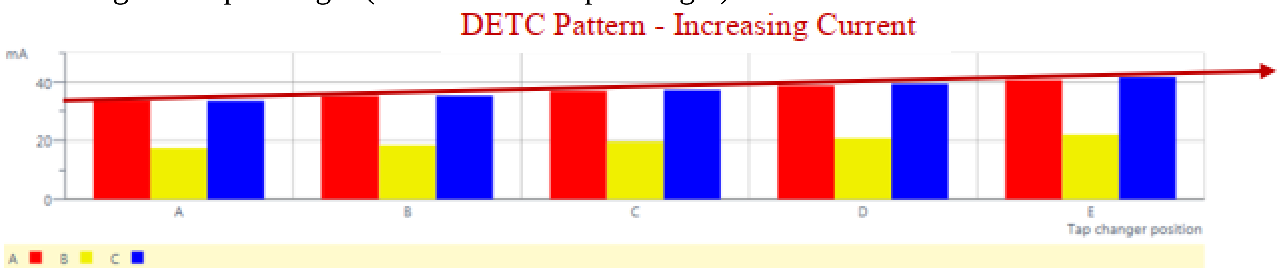

Figure A.5: *Typical DETC Tap-Changer Pattern*

2.) Resistive-Type Load Tap Changer Patterns

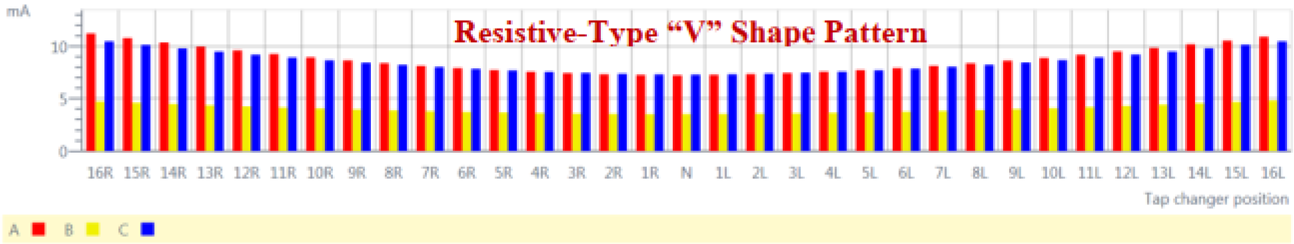

Figure A.6: *Typical Tap-Changer Pattern when Resistive LTC is Located on Secondary Side*

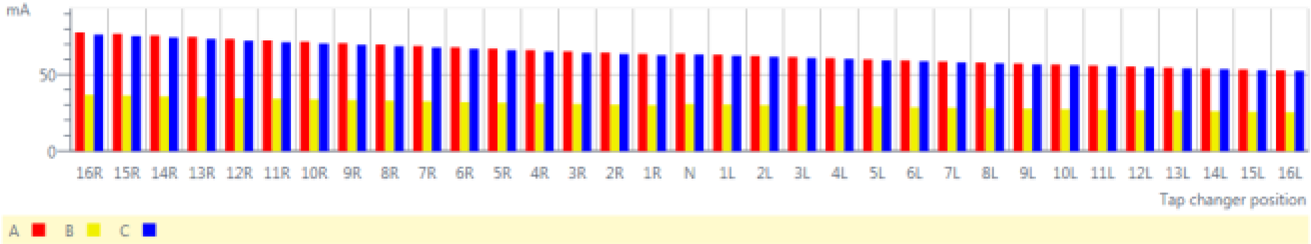

Figure A.7: *Typical Tap-Changer Pattern when Resistive LTC is Located on Primary Side*

3.) Reactive-Type Load Tap Changer Patterns

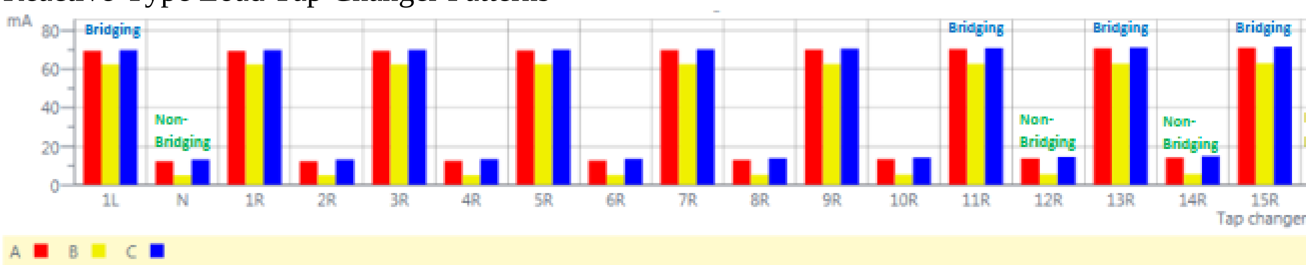

Figure A.8: *Reactive-Type LTC Pattern Example*

Note, regardless of the tap-changer configuration, the expected phase-pattern should not change versus tap-position, and should be consistent with the phase-patterns discussed in the previous sections.

B| Some Other Failure

1. Axial instability (WAI):

Axial instability occurs when the movement of outer winding turns upward or downward. The cause for the axial instability (WAI) failure mode is shown in Figure B.1. The typical cause is over-current which creates high radial forces that subsequently create a buckling deformation. Depending on the severity of the deformation, if the material elastic limit is exceeded, the conductors would break, causing an open-circuit failure. In other hand, opposing axial forces directed axially towards winding centers can lead to conductor tilting. The result of these deformations (radial, axial or both) might cause conductors to collapse inward, thereby causing axial instability.

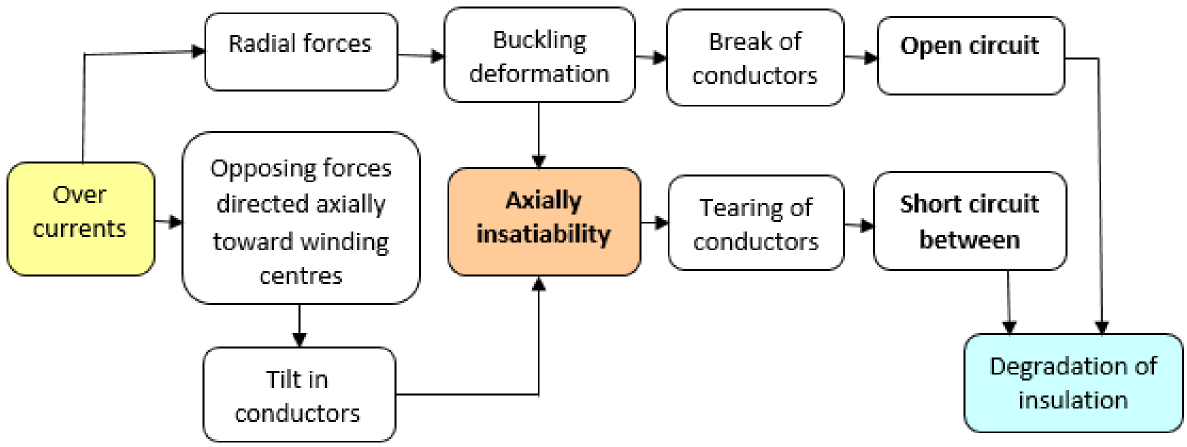

Figure B.1: *Causes and effects for the failure of axially insatiability*

2. Loose clamping structure:

The cause for loose clamping structure failure mode is shown in Figure B.2. The clamping structure can get loosened due to the action of different factors. The most typical causes are paper shrinkage due to drying in old transformers, vibrations caused by the normal operation of the transformer, normal aging or axial forces caused by short-circuiting currents and careless transportation of transformers. This failure cause is very difficult to be detected. The transformer can remain in operation with a loose clamping. Nevertheless, under these conditions, there is a high risk of mechanical deformations during the operation of the transformer. In Figure B.3 is shown the loose clamping structure during un-tanking of the real transformer.

The action of axial force and vibrations move the windings against the clamping ring plates leading to the partial or total destruction (bend or break of clamping plates) of the clamping ring plates resulting in clamping system failure (CSF). Failure of clamping structure is not only caused by axial forces; it is also caused as a result of the normal aging process of power transformers. Clamping failure is a common problem of old transformers, especially when it is excessively dried after refurbishment [32].

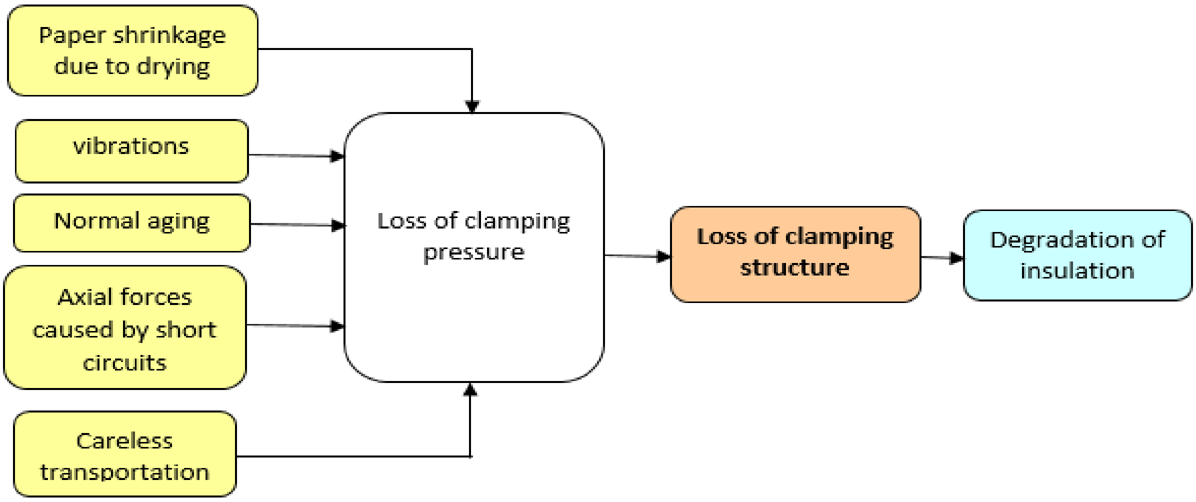

Figure B.2: *Causes and effects of loose clamping structure failure*

Figure B.3: *Illustration of a real case of loose clamping structure*

3. Compression and Hoop tension failure

The cause for the compression hoop tension failure mode is shown in Figure B.4. The action of external short-circuits currents can develop inward radial compressive forces in inner windings (usually LV windings). The inward radial compressive forces can lead to compression tension failure. Compression tension failures can cause the conductor insulation to tear or separate. In extreme cases, inward radial forces compress the conductors leading to breakage once the material elastic limit exceeded [29].

The cause for the buckling hoop tension failure mode is shown in Figure B.4. The action of external short-circuits currents can develop outward radial forces in outer windings, which can lead to hoop tension failure. Hoop tension failure can cause the conductor insulation to tear or separate (break of conductors). In extreme cases, outward radial forces stretch the conductor leading to breakage once the material elastic limit exceeds. Subsequently tearing of the conductors leading to a short circuit between turns, whereas breakage of conductors results in an open circuit [29].

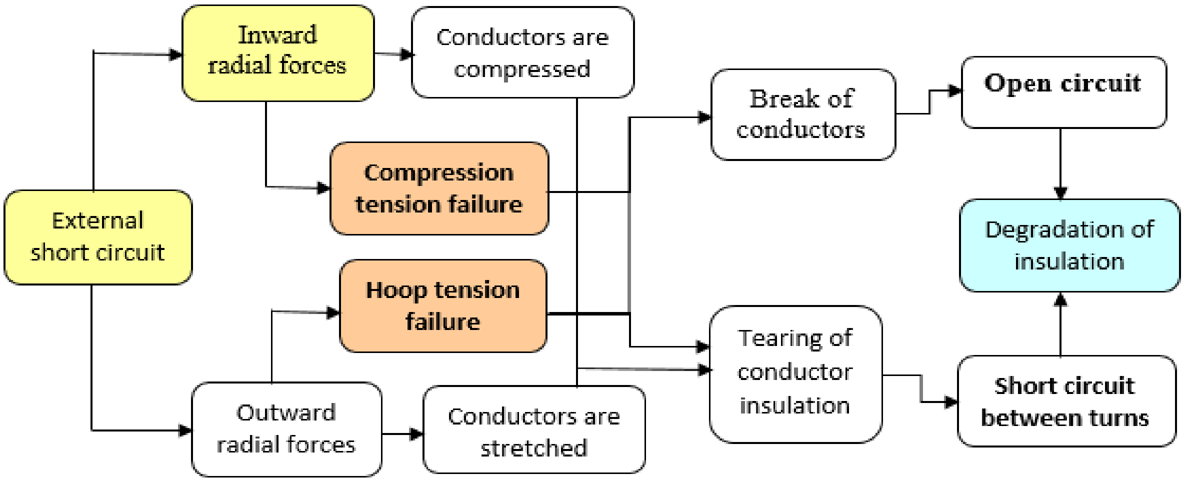

Figure B.4: *Causes and effects of hoop and compression tension failure*

4. Conductor tilting:

Electromagnetic force in the inner discs of a winding creates cumulative force, which is transmitted through the insulation structure. When these forces are more than a certain limit, it causes conductors to tilt. The cause for conductor tilting failure mode is shown in Figure B.5. The ampere-turn imbalance and over-currents creating axial forces tending to move either one coil or other coil part upwards and downwards [27]. The action of the axial forces stresses the clamping rings on one hand and, on the other hand, opposing forces directed towards winding centers could lead to conductor tilting. The conductor tilting leading to the conductor insulation damage, conductor displacements, and inter-turn short circuits in transformers.

An initial conductor tilt, which tends to deform the conductors in a conical shape result in axial instability. Under this condition, the transformer may operate normally for a period of time. However, when the transformer is again under a sudden large increase in current flow, its winding will spread apart. This movement is very sudden and violent, resulting in severe deformation of the windings leading to axial instability and a short circuit between turns [25]. The typical conductor tilting is shown in Figure B.6.

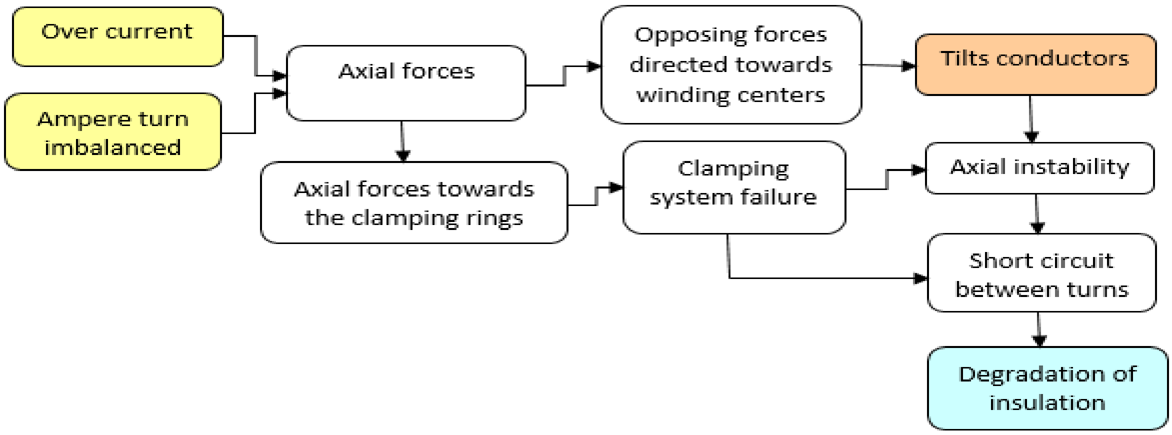

Figure B.5: *Causes and effects of winding conductor tilting failure*

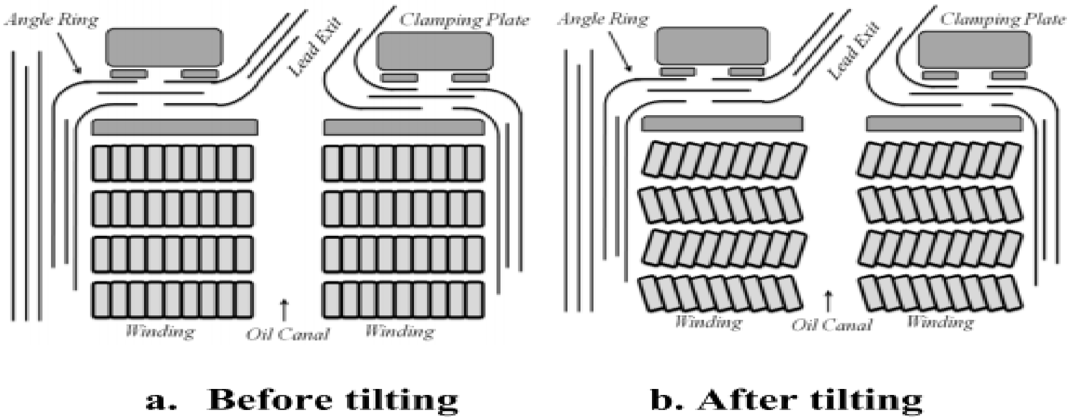

Figure B.6: *Winding conductor tilting*

5. Short circuit to ground (SCTG):

Short-circuit to ground (SCTG) is occurred either by operational loss of insulation between LV windings and the core or operational loss of insulation between internal leads and ground, tank…etc. As shown in Figure B.7.

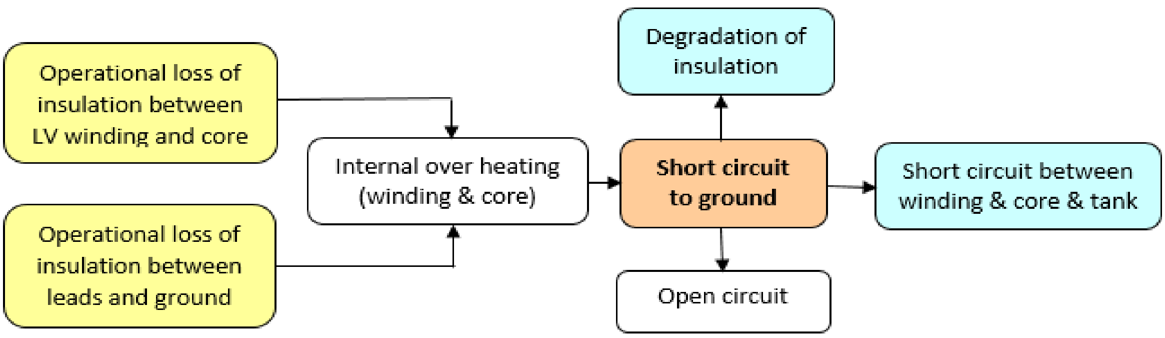

Figure B.7: *Causes and effects of short circuit to ground failure*

Degradation of insulation between the winding and grounded parts such as a tank, core causes overheating in current-carrying elements, this phenomenon can generate gases. Depending on the overheating caused by the short circuit to ground, the burning could also turn into an open-circuit. A short-circuit to ground also leads to condition in which a transformer cannot remain in service [32]. Figure B.8 shows real case of failure to ground found in a transformer.

Figure B.8: *Illustration of a real case of failure to ground*

6. Leakage:

The causes for leakage failure are shown in Figure B.9. The fault in the tank occurs due to environmental stress, corrosion, high humidity and sun radiation resulting in a leakage or cracks in the tank walls. From these leakages and cracks oil spill from the tank causing the reduction of oil. The reduction in oil level results in the reduction of insulation in the transformer and affecting the windings. The oil is also used for cooling purposes so the reduction of oil causes over-heating with damages different parts of the transformer.

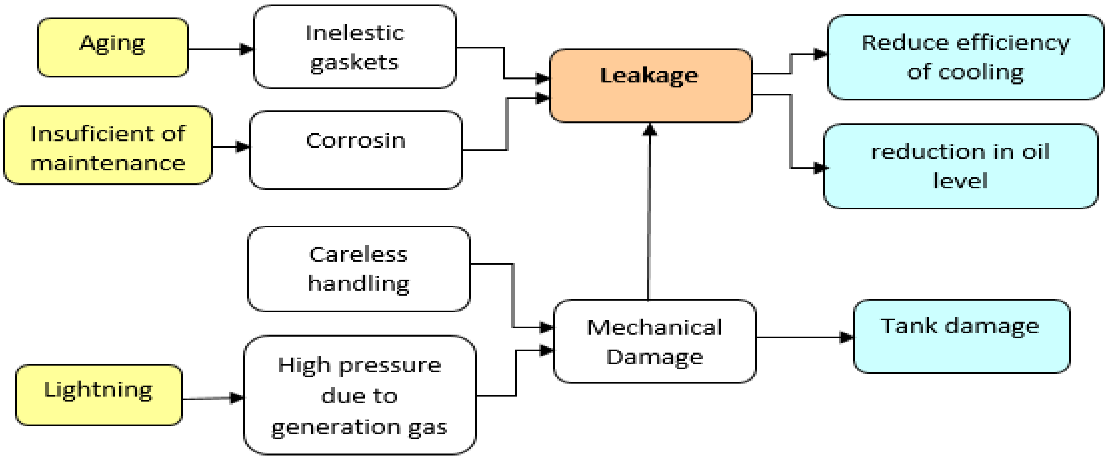

Figure B.9: *causes and effects of leakage failure*

C | Transformer Data

This appendix contains all the different data for the transformers evaluated in the thesis. The results based on these data are shown in Chapter 4.

T3 Data (Msila)

DGA:

Table C.1: *DGA data for T1.*

[ppm] date	**26.12.12**	**20.06.14**	**09.11.16**	**07.01.19**	**20.01.19**	**28.01.19**
Hydrogen	7	10	14	26	37	39
Oxygen	4513	3255	1378	2731	2726	2310
Nitrogen	45377	71634	40120	45555	41525	40220
Carbon monoxide	552	723	542	534	455	561
Carbon dioxide	3351	3319	3307	3244	3054	3139
Methane	29	31	26	22	24	25
Ethene	26	15	11	9	10	12
Ethane	0	<1	9	7	7	7
Ethyne (Acetylene)	26	<1	4	13	19	22

Oil Quality

Table C.2: *Oil sample analysis data for T1.*

Date:	**29.01.2019**
Breakdown voltage [kV]	58
Water content [mg/kg]	12
Neutralization value [mg KOH/g]	0.15
tan(δ) [% ref 90°C]	0.11
Color	6.1
Interfacial Tension	No

Furan

Table C.3: *Oil sample analysis data for T1.*

Date	01.06.16	22.11.16	07.01.19	23.01.19
2-furfural (2-FAL)	0.36	0.4	0.6	0.7
5-hydroxymethyl-2-furfural (5-HMF)	<0.1	<0.1	<0.1	<0.1
5-methyl-2-furfural (5-MEF)	<0.1	<0.1	<0.1	<0.1
2-acetylfuran (2-ACF)	<0.1	<0.1	<0.1	<0.1
2-furfurylalcohol (2-FOL)	<0.1	<0.1	<0.1	<0.1

Insulation Resistance:

Table C.4: *Insulation resistance of transformer T1*

Applied voltage: 5Kv

Test	**Result**
P/E	**700 MΩ**
S/E	**440 MΩ**
T/M	**800 MΩ**
P/S	**920 MΩ**
P/T	**1,3 GΩ**
S/T	**1,4 GΩ**

Turn Ratio:

Phase A:

Position	Nominal V pr.	Nominal V sec.	Nominal Ratio	V pr.		V sec.		Ratio	
001	253000 V	66150.0 V	3.8246 :1	299.93	0.00	78.119 V	0.01 °	3.8394 :1	0.39 %
002	249700 V	66150.0 V	3.7748 :1	299.94	0.00	79.161 V	0.00 °	3.7890 :1	0.38 %
003	246400 V	66150.0 V	3.7249 :1	299.93	0.00	80.228 V	0.00 °	3.7385 :1	0.36 %
004	243100 V	66150.0 V	3.6750 :1	299.94	0.00	81.328 V	0.02 °	3.6880 :1	0.35 %
005	239800 V	66150.0 V	3.6251 :1	299.93	0.00	82.458 V	0.00 °	3.6373 :1	0.34 %
006	236500 V	66150.0 V	3.5752 :1	299.93	0.00	83.620 V	0.00 °	3.5868 :1	0.32 %
007	233200 V	66150.0 V	3.5253 :1	299.94	0.00	84.816 V	0.01 °	3.5363 :1	0.31 %
008	229900 V	66150.0 V	3.4754 :1	299.93	0.00 °	86.041 V	0.01 °	3.4859 :1	0.30 %
009	226600 V	66150.0 V	3.4255 :1	299.95 V	0.00 °	87.309 V	0.00 °	3.4355 :1	0.29 %
010	223300 V	66150.0 V	3.3757 :1	299.92 V	0.00 °	88.605 V	0.02 °	3.3849 :1	0.27 %
011	220000 V	66150.0 V	3.3258 :1	299.95 V	0.00 °	89.955 V	0.00 °	3.3344 :1	0.26 %
012	216700 V	66150.0 V	3.2759 :1	299.92 V	0.00 °	91.328 V	0.01 °	3.2840 :1	0.25 %

Position	Nominal V pr.	Nominal V sec.	Nominal Ratio	V pr.		V sec.		Ratio	
013	213400 V	66150.0 V	3.2260 :1	299.93 V	0.00 °	92.757 V	0.02 °	3.2335 :1	0.23 %
014	210100 V	66150.0 V	3.1761 :1	299.94 V	0.00 °	94.231 V	0.01 °	3.1830 :1	0.22 %
015	206800 V	66150.0 V	3.1262 :1	299.92 V	0.00 °	95.744 V	0.02 °	3.1325 :1	0.20 %
016	203500 V	66150.0 V	3.0763 :1	299.93 V	0.00 °	97.316 V	0.01 °	3.0820 :1	0.18 %
017	200200 V	66150.0 V	3.0265 :1	299.94 V	0.00 °	98.936 V	0.01 °	3.0317 :1	0.17 %
018	196900 V	66150.0 V	2.9766 :1	299.93 V	0.00 °	100.61 V	0.00 °	2.9811 :1	0.15 %
019	193600 V	66150.0 V	2.9267 :1	299.92 V	0.00 °	102.33 V	0.00 °	2.9308 :1	0.14 %
020	190300 V	66150.0 V	2.8768 :1	299.92 V	0.00 °	104.13 V	0.02 °	2.8803 :1	0.12 %
021	187000 V	66150.0 V	2.8269 :1	299.93 V	0.00 °	105.99 V	0.01 °	2.8299 :1	0.11 %

Phase B:

Position	Nominal V pr.	Nominal V sec.	Nominal Ratio	V pr.		V sec.		Ratio	
021	187000 V	66150.0 V	2.8269 :1	299.93 V	0.00 °	105.91 V	0.01 °	2.8320 :1	0.18 %
020	190300 V	66150.0 V	2.8768 :1	299.92 V	0.00 °	104.05 V	-0.01 °	2.8824 :1	0.19 %
019	193600 V	66150.0 V	2.9267 :1	299.93 V	0.00 °	102.26 V	0.00 °	2.9329 :1	0.21 %
018	196900 V	66150.0 V	2.9766 :1	299.94 V	0.00 °	100.54 V	0.00 °	2.9834 :1	0.23 %
017	200200 V	66150.0 V	3.0265 :1	299.93 V	0.00 °	98.860 V	0.01 °	3.0339 :1	0.25 %
016	203500 V	66150.0 V	3.0763 :1	299.93 V	0.00 °	97.240 V	0.01 °	3.0844 :1	0.26 %
015	206800 V	66150.0 V	3.1262 :1	299.93 V	0.00 °	95.672 V	0.02 °	3.1350 :1	0.28 %

Position	Nominal V pr.	Nominal V sec.	Nominal Ratio	V pr.		V sec.		Ratio	
014	210100 V	66150.0 V	3.1761 :1	299.93 V	0.00 °	94.157 V	0.01 °	3.1854 :1	0.29 %
013	213400 V	66150.0 V	3.2260 :1	299.94 V	0.00 °	92.688 V	0.01 °	3.2360 :1	0.31 %
012	216700 V	66150.0 V	3.2759 :1	299.94 V	0.00 °	91.266 V	0.00 °	3.2864 :1	0.32 %
011	220000 V	66150.0 V	3.3258 :1	299.92 V	0.00 °	89.875 V	0.00 °	3.3371 :1	0.34 %
010	223300 V	66150.0 V	3.3757 :1	299.94 V	0.00 °	88.542 V	0.01 °	3.3875 :1	0.35 %
009	226600 V	66150.0 V	3.4255 :1	299.93 V	0.00 °	87.237 V	0.01 °	3.4381 :1	0.37 %
008	229900 V	66150.0 V	3.4754 :1	299.92 V	0.00 °	85.971 V	0.02 °	3.4886 :1	0.38 %
007	233200 V	66150.0 V	3.5253 :1	299.94 V	0.00 °	84.748 V	0.00 °	3.5392 :1	0.39 %
006	236500 V	66150.0 V	3.5752 :1	299.92 V	0.00 °	83.550 V	0.00 °	3.5897 :1	0.41 %
005	239800 V	66150.0 V	3.6251 :1	299.93 V	0.00 °	82.392 V	0.01 °	3.6403 :1	0.42 %
004	243100 V	66150.0 V	3.6750 :1	299.94 V	0.00 °	81.265 V	0.01 °	3.6909 :1	0.43 %
003	246400 V	66150.0 V	3.7249 :1	299.93 V	0.00 °	80.166 V	0.01 °	3.7414 :1	0.44 %
002	249700 V	66150.0 V	3.7748 :1	299.92 V	0.00 °	79.095 V	0.01 °	3.7919 :1	0.45 %
001	253000 V	66150.0 V	3.8246 :1	299.93 V	0.00 °	78.056 V	0.02 °	3.8425 :1	0.47 %

Phase C:

Position	Nominal V pr.	Nominal V sec.	Nominal Ratio	V pr.		V sec.		Ratio	
001	253000 V	66150.0 V	3.8246 :1	299.94 V	0.00 °	78.122 V	0.03 °	3.8394 :1	0.39 %
002	249700 V	66150.0 V	3.7748 :1	299.94 V	0.00 °	79.165 V	0.01 °	3.7888 :1	0.37 %

Position	Nominal V pr.	Nominal V sec.	Nominal Ratio	V pr.		V sec.		Ratio	
003	246400 V	66150.0 V	3.7249 :1	299.93 V	0.00 °	80.232 V	0.01 °	3.7383 :1	0.36 %
004	243100 V	66150.0 V	3.6750 :1	299.93 V	0.00 °	81.330 V	0.01 °	3.6878 :1	0.35 %
005	239800 V	66150.0 V	3.6251 :1	299.94 V	0.00 °	82.461 V	0.01 °	3.6374 :1	0.34 %
006	236500 V	66150.0 V	3.5752 :1	299.92 V	0.00 °	83.618 V	0.00 °	3.5868 :1	0.32 %
007	233200 V	66150.0 V	3.5253 :1	299.94 V	0.00 °	84.816 V	0.02 °	3.5364 :1	0.31 %
008	229900 V	66150.0 V	3.4754 :1	299.94 V	0.00 °	86.046 V	0.01 °	3.4858 :1	0.30 %
009	226600 V	66150.0 V	3.4255 :1	299.95 V	0.00 °	87.316 V	0.03 °	3.4352 :1	0.28 %
010	223300 V	66150.0 V	3.3757 :1	299.91 V	0.00 °	88.605 V	0.00 °	3.3848 :1	0.27 %
011	220000 V	66150.0 V	3.3258 :1	299.93 V	0.00 °	89.952 V	0.00 °	3.3344 :1	0.26 %
012	216700 V	66150.0 V	3.2759 :1	299.94 V	0.00 °	91.340 V	0.00 °	3.2838 :1	0.24 %
013	213400 V	66150.0 V	3.2260 :1	299.92 V	0.00 °	92.757 V	0.00 °	3.2334 :1	0.23 %
014	210100 V	66150.0 V	3.1761 :1	299.92 V	0.00 °	94.227 V	0.02 °	3.1829 :1	0.21 %
015	206800 V	66150.0 V	3.1262 :1	299.94 V	0.00 °	95.750 V	0.02 °	3.1325 :1	0.20 %
016	203500 V	66150.0 V	3.0763 :1	299.93 V	0.00 °	97.318 V	0.01 °	3.0819 :1	0.18 %
017	200200 V	66150.0 V	3.0265 :1	299.93 V	0.00 °	98.938 V	0.02 °	3.0315 :1	0.17 %
018	196900 V	66150.0 V	2.9766 :1	299.93 V	0.00 °	100.61 V	0.01 °	2.9810 :1	0.15 %
019	193600 V	66150.0 V	2.9267 :1	299.92 V	0.00 °	102.34 V	0.01 °	2.9305 :1	0.13 %
020	190300 V	66150.0 V	2.8768 :1	299.92 V	0.00 °	104.13 V	0.00 °	2.8801 :1	0.12 %
021	187000 V	66150.0 V	2.8269 :1	299.94 V	0.00 °	106.00 V	0.02 °	2.8297 :1	0.10 %

Leakage Reactance:

Phase A:

Output	Freq.	I AC		V1 AC		Z	
1.000 A	15.00 Hz	14.06 mA	0.00 °	73.956 V	81.92 °	5260.0 Ω	81.92 °
1.000 A	30.00 Hz	12.75 mA	0.00 °	107.70 V	76.32 °	8447.3 Ω	76.32 °
1.000 A	50.00 Hz	10.78 mA	0.00 °	143.96 V	69.07 °	13355 Ω	69.07 °
1.000 A	50.00 Hz	10.85 mA	0.00 °	143.94 V	69.31 °	13266 Ω	69.31 °
1.000 A	50.00 Hz	10.85 mA	0.00 °	143.90 V	69.33 °	13262 Ω	69.33 °
1.000 A	150.00 Hz	4.22 mA	0.00 °	134.76 V	64.90 °	31934 Ω	64.90 °
1.000 A	200.00 Hz	3.01 mA	0.00 °	128.38 V	63.36 °	42650 Ω	63.36 °
1.000 A	250.00 Hz	2.08 mA	0.00 °	121.35 V	58.48 °	58342 Ω	58.48 °
1.000 A	300.00 Hz	1.37 mA	0.00 °	112.34 V	51.68 °	82002 Ω	51.68 °
1.000 A	350.00 Hz	890.00 µA	0.00 °	95.687 V	36.67 °	107.51 kΩ	36.67 °
1.000 A	400.00 Hz	680.00 µA	0.00 °	83.348 V	0.38 °	122.57 kΩ	0.38 °
1.000 A	400.00 Hz	750.00 µA	0.00 °	83.356 V	2.44 °	111.14 kΩ	2.44 °

Phase B:

Sortie	Freq.	I AC		V1 AC		Z	
1.000 A	15.00 Hz	11.02 mA	0.00 °	73.865 V	81.48 °	6702.8 Ω	81.48 °
1.000 A	30.00 Hz	10.00 mA	0.00 °	107.72 V	75.53 °	10772 Ω	75.53 °
1.000 A	50.00 Hz	8.49 mA	0.00 °	143.97 V	67.70 °	16957 Ω	67.70 °
1.000 A	100.00 Hz	4.91 mA	0.00 °	141.23 V	64.68 °	28764 Ω	64.68 °
1.000 A	150.00 Hz	3.26 mA	0.00 °	134.79 V	62.29 °	41346 Ω	62.29 °
1.000 A	200.00 Hz	2.23 mA	0.00 °	128.37 V	57.79 °	57567 Ω	57.79 °
1.000 A	250.00 Hz	1.47 mA	0.00 °	121.24 V	50.08 °	82477 Ω	50.08 °
1.000 A	300.00 Hz	930.00 µA	0.00 °	112.25 V	32.85 °	120.70 kΩ	32.85 °
1.000 A	350.00 Hz	740.00 µA	0.00 °	95.788 V	-1.59 °	129.44 kΩ	-1.59 °
1.000 A	400.00 Hz	710.00 µA	0.00 °	83.384 V	-40.63 °	117.44 kΩ	-40.63 °

Phase C:

Sortie	Freq.	I AC		V1 AC		Z	
1.000 A	15.00 Hz	12.89 mA	0.00 °	73.866 V	81.36 °	5730.5 Ω	81.36 °
1.000 A	30.00 Hz	11.69 mA	0.00 °	107.70 V	75.37 °	9213.3 Ω	75.37 °
1.000 A	50.00 Hz	9.98 mA	0.00 °	143.97 V	67.69 °	14426 Ω	67.69 °
1.000 A	100.00 Hz	5.87 mA	0.00 °	141.20 V	65.18 °	24054 Ω	65.18 °

Sortie	Freq.	I AC		V1 AC		Z	
1.000 A	150.00 Hz	3.98 mA	0.00 °	134.76 V	63.61 °	33860 Ω	63.61 °
1.000 A	200.00 Hz	2.78 mA	0.00 °	128.41 V	60.67 °	46191 Ω	60.67 °
1.000 A	250.00 Hz	1.87 mA	0.00 °	121.28 V	55.41 °	64857 Ω	55.41 °
1.000 A	300.00 Hz	1.22 mA	0.00 °	112.07 V	44.96 °	91860 Ω	44.96 °
1.000 A	350.00 Hz	870.00 µA	0.00 °	95.866 V	23.48 °	110.19 kΩ	23.48 °
1.000 A	400.00 Hz	790.00 µA	0.00 °	83.445 V	-15.82 °	105.63 kΩ	-15.82 °

OLTC Test:

Phase A:

Position	Time	R mea.	Dev.	R ref.	Ripple	Slope	I CC	V CC
001	113.000 s	469.30 mΩ	0.07 %	579.61 mΩ	n/a	n/a	3.0000 A	1.4079 V
002	41.000 s	465.17 mΩ	0.07 %	574.52 mΩ	0.98 %	-90.20 mA/s	3.0001 A	1.3956 V
003	66.000 s	460.70 mΩ	0.07 %	568.99 mΩ	1.49 %	-94.50 mA/s	3.0000 A	1.3821 V
004	35.000 s	454.20 mΩ	0.04 %	560.97 mΩ	0.99 %	-68.00 mA/s	3.0000 A	1.3626 V
005	34.000 s	445.11 mΩ	0.05 %	549.74 mΩ	1.42 %	-90.50 mA/s	3.0000 A	1.3353 V
006	32.000 s	438.89 mΩ	0.03 %	542.06 mΩ	1.00 %	-67.50 mA/s	3.0001 A	1.3167 V
007	108.000 s	434.97 mΩ	0.06 %	537.22 mΩ	1.44 %	-84.00 mA/s	3.0000 A	1.3049 V
008	34.000 s	426.99 mΩ	0.07 %	527.35 mΩ	1.00 %	-52.70 mA/s	3.0001 A	1.2810 V
009	34.000 s	420.96 mΩ	0.03 %	519.91 mΩ	1.49 %	-77.80 mA/s	3.0001 A	1.2629 V
010	39.000 s	415.50 mΩ	0.08 %	513.17 mΩ	0.97 %	-47.40 mA/s	3.0000 A	1.2465 V
011	41.000 s	405.38 mΩ	0.06 %	500.67 mΩ	1.71 %	-198.10 mA/s	3.0000 A	1.2161 V
012	89.000 s	416.45 mΩ	0.06 %	514.33 mΩ	2.38 %	-289.30 mA/s	3.0000 A	1.2493 V
013	48.000 s	430.59 mΩ	0.03 %	531.81 mΩ	1.76 %	-105.90 mA/s	3.0000 A	1.2918 V
014	62.000 s	439.54 mΩ	0.08 %	542.86 mΩ	1.12 %	-57.20 mA/s	3.0000 A	1.3186 V
015	140.000 s	443.18 mΩ	0.08 %	547.35 mΩ	1.44 %	-74.00 mA/s	3.0000 A	1.3295 V
016	76.000 s	444.56 mΩ	0.08 %	549.05 mΩ	9.3e+2 m%	-43.10 mA/s	3.0000 A	1.3337 V
017	36.000 s	444.45 mΩ	0.08 %	548.92 mΩ	1.45 %	-74.70 mA/s	3.0000 A	1.3333 V
018	27.000 s	449.73 mΩ	0.07 %	555.44 mΩ	0.97 %	-46.00 mA/s	3.0000 A	1.3492 V
019	33.000 s	454.59 mΩ	0.08 %	561.44 mΩ	1.29 %	-68.60 mA/s	3.0000 A	1.3638 V
020	56.000 s	464.80 mΩ	0.08 %	574.06 mΩ	8.2e+2 m%	-36.80 mA/s	3.0000 A	1.3944 V
021	43.000 s	468.24 mΩ	0.07 %	578.30 mΩ	1.16 %	-57.10 mA/s	3.0000 A	1.4047 V

Phase B:

Position	Time	R mea.	Dev.	R ref.	Ripple	Slope	I CC	V CC
021	72.000 s	793.04 mΩ	0.06 %	0.99935 Ω	n/a	n/a	3.0000 A	2.3791 V
020	82.000 s	792.82 mΩ	0.09 %	0.99908 Ω	3.68 %	-434.30 mA/s	3.0000 A	2.3785 V
019	181.000 s	783.82 mΩ	0.09 %	0.98774 Ω	3.43 %	-410.90 mA/s	3.0000 A	2.3515 V
018	218.000 s	769.53 mΩ	0.09 %	0.96974 Ω	3.78 %	-444.40 mA/s	3.0000 A	2.3086 V
017	72.000 s	756.65 mΩ	0.09 %	0.95350 Ω	3.32 %	-400.30 mA/s	3.0001 A	2.2700 V
016	48.000 s	753.21 mΩ	0.09 %	949.17 mΩ	3.63 %	-437.40 mA/s	3.0000 A	2.2596 V
015	50.000 s	740.44 mΩ	0.09 %	933.07 mΩ	3.21 %	-389.80 mA/s	3.0000 A	2.2213 V
014	39.000 s	729.82 mΩ	0.08 %	919.69 mΩ	3.45 %	-421.00 mA/s	3.0000 A	2.1895 V
013	65.000 s	712.81 mΩ	0.09 %	898.25 mΩ	3.09 %	-376.10 mA/s	3.0000 A	2.1384 V
012	40.000 s	708.57 mΩ	0.04 %	892.91 mΩ	3.32 %	-402.90 mA/s	3.0000 A	2.1257 V
011	140.000 s	699.66 mΩ	0.07 %	881.69 mΩ	3.01 %	-363.90 mA/s	3.0000 A	2.0990 V
010	78.000 s	704.20 mΩ	0.09 %	887.40 mΩ	3.32 %	-404.90 mA/s	3.0000 A	2.1126 V
009	234.000 s	699.80 mΩ	0.08 %	881.86 mΩ	2.90 %	-360.80 mA/s	3.0000 A	2.0994 V
008	55.000 s	706.95 mΩ	0.08 %	890.87 mΩ	3.11 %	-377.90 mA/s	3.0000 A	2.1209 V
007	160.000 s	733.81 mΩ	0.09 %	924.72 mΩ	2.86 %	-344.70 mA/s	3.0000 A	2.2014 V
006	40.000 s	739.15 mΩ	0.06 %	931.45 mΩ	3.11 %	-378.70 mA/s	3.0000 A	2.2175 V
005	80.000 s	749.17 mΩ	0.08 %	944.08 mΩ	2.80 %	-343.00 mA/s	3.0000 A	2.2475 V
004	48.000 s	756.15 mΩ	0.09 %	0.95287 Ω	2.91 %	-358.70 mA/s	3.0000 A	2.2684 V
003	43.000 s	763.11 mΩ	0.08 %	0.96164 Ω	2.68 %	-326.90 mA/s	3.0000 A	2.2893 V
002	50.000 s	768.58 mΩ	0.05 %	0.96854 Ω	2.85 %	-350.70 mA/s	3.0000 A	2.3057 V
001	101.000 s	775.93 mΩ	0.08 %	0.97779 Ω	2.61 %	-323.40 mA/s	3.0000 A	2.3278 V

Phase C:

Position	Time	R mea.	Dev.	R ref.	Ripple	Slope	I CC	V CC
001	86.000 s	544.09 mΩ	0.09 %	685.64 mΩ	n/a	n/a	3.0000 A	1.6323 V
002	50.000 s	533.90 mΩ	0.03 %	672.80 mΩ	0.99 %	-104.70 mA/s	3.0000 A	1.6017 V
003	50.000 s	525.84 mΩ	0.08 %	662.65 mΩ	2.02 %	-177.60 mA/s	3.0000 A	1.5775 V
004	49.000 s	517.04 mΩ	0.09 %	651.55 mΩ	1.00 %	-98.60 mA/s	3.0000 A	1.5511 V
005	33.000 s	509.67 mΩ	0.07 %	642.26 mΩ	1.59 %	-127.60 mA/s	3.0000 A	1.5290 V
006	33.000 s	503.31 mΩ	0.07 %	634.25 mΩ	1.09 %	-93.90 mA/s	3.0000 A	1.5099 V
007	33.000 s	495.82 mΩ	0.07 %	624.82 mΩ	1.84 %	-158.50 mA/s	3.0000 A	1.4875 V
008	40.000 s	489.33 mΩ	0.09 %	616.64 mΩ	1.12 %	-94.80 mA/s	3.0000 A	1.4680 V

Position	Time	R mea.	Dev.	R ref.	Ripple	Slope	I CC	V CC
009	35.000 s	482.01 mΩ	0.04 %	607.41 mΩ	1.78 %	-148.90 mA/s	3.0000 A	1.4460 V
010	37.000 s	475.09 mΩ	0.09 %	598.68 mΩ	1.22 %	-91.40 mA/s	3.0000 A	1.4253 V
011	41.000 s	465.19 mΩ	0.09 %	586.21 mΩ	2.20 %	-251.40 mA/s	3.0000 A	1.3956 V
012	50.000 s	484.49 mΩ	0.01 %	610.53 mΩ	2.78 %	-335.70 mA/s	3.0000 A	1.4535 V
013	29.000 s	490.53 mΩ	0.08 %	618.14 mΩ	1.98 %	-146.50 mA/s	3.0000 A	1.4716 V
014	28.000 s	496.74 mΩ	0.05 %	625.97 mΩ	1.35 %	-83.50 mA/s	3.0000 A	1.4902 V
015	29.000 s	503.11 mΩ	0.06 %	634.01 mΩ	1.63 %	-99.50 mA/s	3.0000 A	1.5093 V
016	37.000 s	509.35 mΩ	0.00 %	641.86 mΩ	1.24 %	-61.30 mA/s	3.0000 A	1.5280 V
017	34.000 s	515.54 mΩ	0.01 %	649.66 mΩ	1.64 %	-85.30 mA/s	3.0000 A	1.5466 V
018	41.000 s	521.36 mΩ	0.01 %	656.99 mΩ	1.17 %	-57.10 mA/s	3.0000 A	1.5641 V
019	49.000 s	527.72 mΩ	0.01 %	665.01 mΩ	1.72 %	-96.10 mA/s	3.0000 A	1.5831 V
020	41.000 s	533.53 mΩ	0.01 %	672.33 mΩ	1.20 %	-64.10 mA/s	3.0000 A	1.6006 V
021	37.000 s	539.49 mΩ	0.01 %	679.85 mΩ	1.39 %	-72.70 mA/s	3.0000 A	1.6185 V

Winding Resistance:

	Rmin. (μΩ)	**Rmax.** (Ω)	**Rmeas.** (mΩ)	**Dev.** (%)	**Time** (s **)**	**Tmea.** (°C)	**T ref.** (°C)	**R ref.** (mΩ)
PH-A-POS-2	40	2	122.12	0.30	203	13	75	152.65
PH-A-AY	40	2	35.026	0.33	105	13	75	43.782
PH-B-POS-1	33.33	1.667	156.08	0.27	313	11	75	196.69
PH-B-POS-2	40	2	139.85	0.26	81	14	75	174.11
PH-B-BY	40	2	49.559	0.21	66	14	75	61.7
PH-C-POS-1	33.33	1.667	173.04	0.16	116	11	75	218.05
PH-C-POS-2	40	2	149.04	0.29	220	15	75	184.81
PH-C-CY	40	2	49.559	0.1	66	14	75	61.7

Power Factor:

<u>220 KV side:</u>

220 KV-GST:

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2000 V	8.0148 mA	*50.00 Hz	12.750 nF	0.6493 %
4000.00 V	4017 V	16.090 mA	*50.00 Hz	12.748 nF	0.6550 %
6000.00 V	6012 V	24.082 mA	*50.00 Hz	12.747 nF	0.6579 %
8000.00 V	8009 V	32.082 mA	*50.00 Hz	12.747 nF	0.6564 %

Phase A UST-A:

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2019 V	226.29 µA	*50.00 Hz	355.80 pF	-7.1697 %
4000.00 V	4016 V	449.97 µA	*50.00 Hz	355.73 pF	-7.1585 %
6000.00 V	6014 V	673.85 µA	*50.00 Hz	355.73 pF	-7.0975 %
8000.00 V	7999 V	896.78 µA	*50.00 Hz	355.95 pF	-7.0971 %

Phase B UST-B:

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2018 V	172.50 µA	*50.00 Hz	272.08 pF	-1.9275 %
4000.00 V	4009 V	335.75 µA	*50.00 Hz	266.54 pF	-1.5400 %
6000.00 V	6012 V	491.74 µA	*50.00 Hz	260.33 pF	-0.9700 %
8000.00 V	7999 V	643.30 µA	*50.00 Hz	255.99 pF	-0.5981 %

Phase C: (UST-A)

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2009 V	186.03 µA	*50.00 Hz	294.57 pF	-3.8955 %
6000.00 V	6010 V	557.52 µA	*50.00 Hz	295.04 pF	-3.8600 %
8000.00 V	7999 V	742.92 µA	*50.00 Hz	295.41 pF	-3.8441 %
4000.00 V	4007 V	371.97 µA	*50.00 Hz	295.28 pF	-3.9209 %

Neutral (UST-B):

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2009 V	159.84 µA	*50.00 Hz	253.17 pF	-3.1455 %
4000.00 V	4002 V	322.56 µA	*50.00 Hz	256.32 pF	-3.2142 %
6000.00 V	5977 V	525.77 µA	*50.00 Hz	278.98 pF	-3.3180 %
8000.00 V	7999 V	592.41 µA	*50.00 Hz	235.69 pF	-1.9514 %

66 KV side:

66 KV GST:

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2000 V	10.711 mA	*50.00 Hz	17.042 nF	0.8004 %
4000.00 V	4000 V	21.420 mA	*50.00 Hz	17.042 nF	0.8036 %
6000.00 V	6010 V	32.181 mA	*50.00 Hz	17.041 nF	0.8145 %
8000.00 V	8009 V	42.889 mA	*50.00 Hz	17.041 nF	0.8149 %

Phase A-66KV:

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2010 V	212.90 µA	*50.00 Hz	337.01 pF	-3.0861 %
4000.00 V	4018 V	425.51 µA	*50.00 Hz	336.95 pF	-3.0794 %
6000.00 V	6011 V	636.72 µA	*50.00 Hz	337.02 pF	-3.0683 %
8000.00 V	7999 V	847.66 µA	*50.00 Hz	337.15 pF	-3.0795 %

Phase B-66KV:

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2010 V	234.07 µA	*50.00 Hz	370.48 pF	-3.9494 %
4000.00 V	4008 V	466.66 µA	*50.00 Hz	370.29 pF	-3.9451 %
6000.00 V	6015 V	700.32 µA	*50.00 Hz	370.34 pF	-3.8864 %
8000.00 V	8000 V	931.94 µA	*50.00 Hz	370.56 pF	-3.8426 %

Phase C-66KV:

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2019 V	279.46 µA	*50.00 Hz	439.73 pF	-6.5808 %
4000.00 V	4009 V	554.56 µA	*50.00 Hz	439.41 pF	-6.5598 %
6000.00 V	6009 V	831.39 µA	*50.00 Hz	439.45 pF	-6.5267 %
8000.00 V	7999 V	1.1073 mA	*50.00 Hz	439.69 pF	-6.5368 %

Neutral (UST-B)

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2018 V	233.26 µA	*50.00 Hz	367.66 pF	-3.8700 %
4000.00 V	4000 V	461.99 µA	*50.00 Hz	367.37 pF	-3.8666 %
6000.00 V	6012 V	694.46 µA	*50.00 Hz	367.39 pF	-3.8043 %
8000.00 V	7999 V	924.12 µA	*50.00 Hz	367.48 pF	-3.7580 %

11 KV Bushing:

11KV-GST:

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2010 V	6.5190 mA	*50.00 Hz	10.321 nF	0.5760 %
4000.00 V	4010 V	13.002 mA	*50.00 Hz	10.319 nF	0.5767 %
6000.00 V	6009 V	19.486 mA	*50.00 Hz	10.318 nF	0.5781 %
8000.00 V	7999 V	25.939 mA	*50.00 Hz	10.319 nF	0.5791 %

11 KV-Bushing A-PF (UST-A):

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2009 V	184.25 µA	*50.00 Hz	291.27 pF	-6.6423 %
4000.00 V	4010 V	367.31 µA	*50.00 Hz	290.96 pF	-6.5430 %
6000.00 V	6014 V	550.98 µA	*50.00 Hz	291.03 pF	-6.4776 %
8000.00 V	7999 V	733.68 µA	*50.00 Hz	291.34 pF	-6.5014 %

11 KV-Bushing B-PF (UST-B):

V test	V meas.	I mesa.	Frequency	Cp	DF
2000.00 V	2007 V	355.71 µA	*50.00 Hz	564.28 pF	0.6743 %
4000.00 V	4010 V	710.84 µA	*50.00 Hz	564.29 pF	0.6778 %
6000.00 V	6011 V	1.0656 mA	*50.00 Hz	564.31 pF	0.6787 %
8000.00 V	7999 V	1.4182 mA	*50.00 Hz	564.33 pF	0.6779 %

11 KV-Bushing C-PF (UST-A):

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2018 V	364.38 µA	*50.00 Hz	574.69 pF	0.6373 %
4000.00 V	4019 V	725.53 µA	*50.00 Hz	574.69 pF	0.6415 %
6000.00 V	6012 V	1.0854 mA	*50.00 Hz	574.70 pF	0.6415 %
8000.00 V	8009 V	1.4460 mA	*50.00 Hz	574.72 pF	0.6395 %

11 KV-Bushing Y-PF (UST-A):

V test	V meas.	I meas.	Frequency	Cp	DF
2000.00 V	2018 V	189.28 µA	*50.00 Hz	298.10 pF	-5.1351 %
4000.00 V	4008 V	375.28 µA	*50.00 Hz	297.68 pF	-5.1059 %
6000.00 V	6011 V	562.87 µA	*50.00 Hz	297.73 pF	-4.9433 %
8000.00 V	8009 V	750.18 µA	*50.00 Hz	297.82 pF	-4.8401 %

D| The causes of failure mode of power transformer subsystems

Oil and paper insulation:

The solid insulation is cellulose based products such as pressboard and paper is inserted between layers of windings. Its function is to provide dielectric and mechanical isolation to the windings for arcing prevention. The transformer active parts are immersed into the oil to provide cooling medium as well as insulation system. The oil quality may greatly affect the cooling properties and insulation of the transformer. The causes for the failure of oil-paper insulation are shown in Figure D.1.

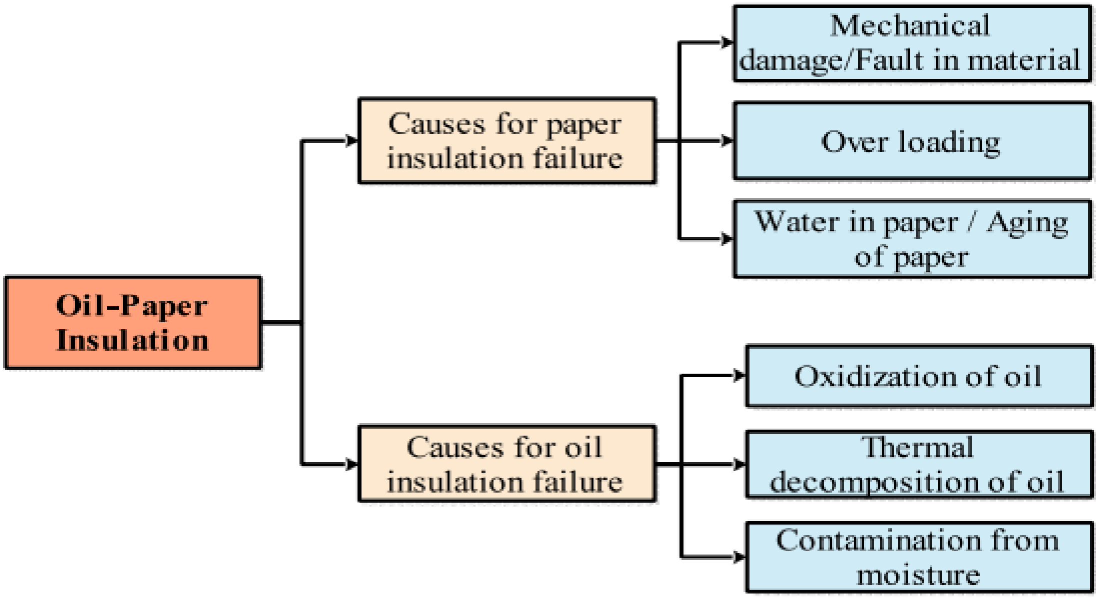

Figure D.1: *Causes for the failure of oil-paper insulation*

Winding:

The winding is an important active part of a transformer, and their function is to carry current. The winding consists of copper, paper and pressboard. The windings are arranged either shell type or core type based on the requirement. The primary side of the winding has external connections (leads or taps) in order to perform voltage ratio adjustment. During the operation, winding undergo various stress causing winding failures, which are shown in Figure D.2.

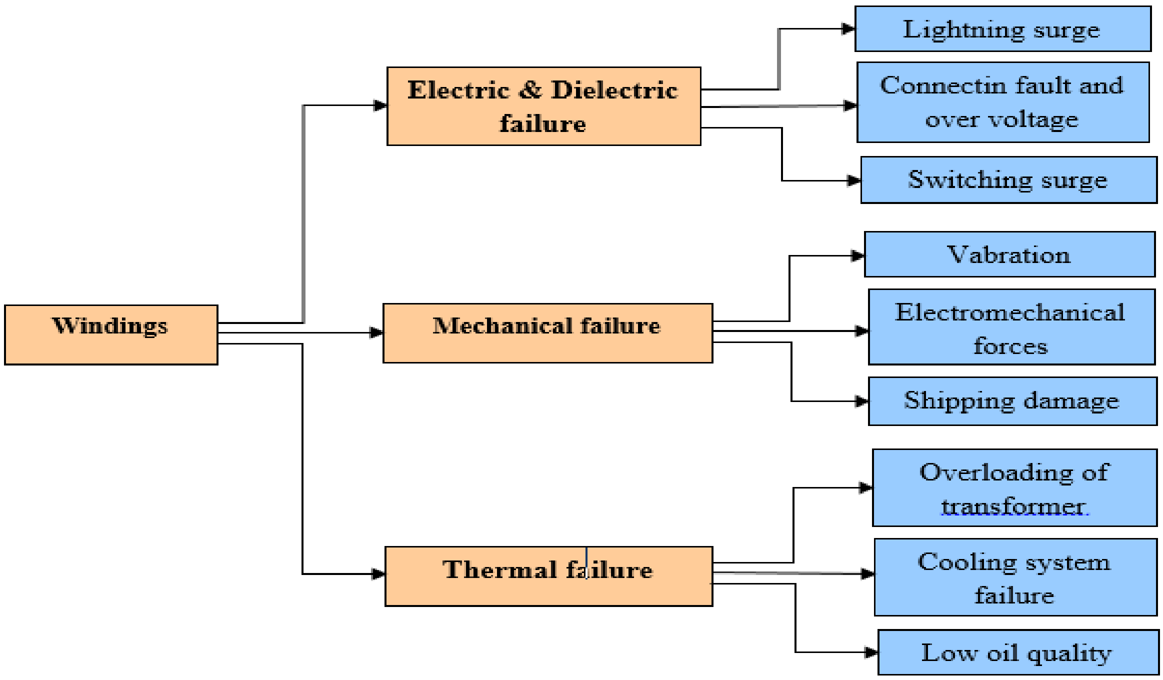

Figure D.2: *Causes for the failure of winding*

Bushing:

The bushing provides insulation between the windings electrical connection and the main tank. The bushings size varies according to the operating voltage and current. There are two main categories of bushings: solid and capacitance graded. Solid bushings are used up to 25 kV, whereas capacitance graded bushings are used for above 25 kV. Bushing main components are conductive part (usually copper or aluminum) and insulating part (e.g. porcelain, glass, resin-bounded paper, or epoxy insulators porcelain). The identified main factors for busing failure causes are shown in Figure D.3.

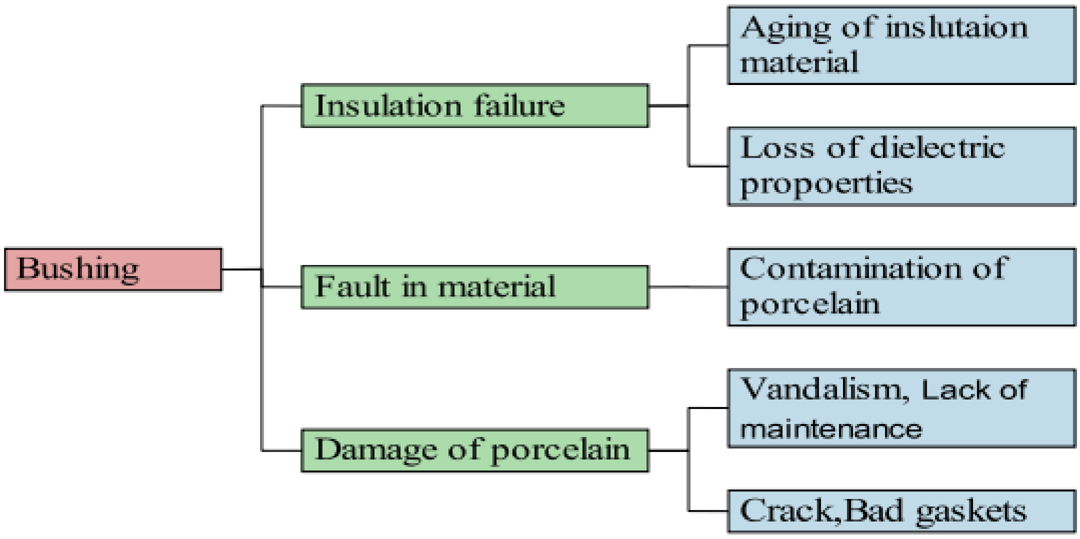

Figure D.3: *Causes for bushing failures*

Tap Changer:

Tap changer is the most complex part of the transformer and also an important one. The function of the tap changer is to regulate the voltage level in the transformer. It provides uninterrupted current flow during the operation from one tap to other. There are two types of tap changer as diverter switch and the tap selector switch. Tap changer can be located either inside the main tank or outside its separate compartment. The identified main factors for tap changer failure causes are shown in Figure D.4.

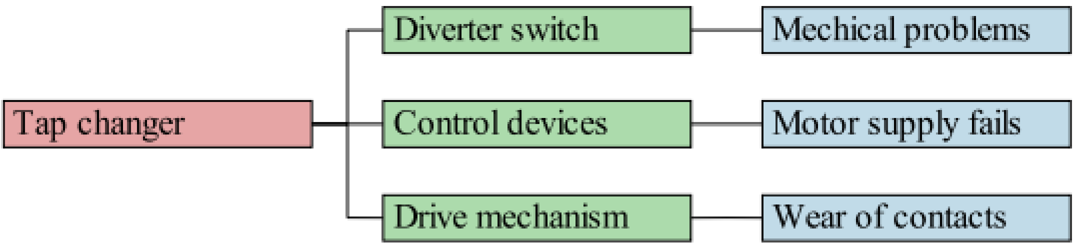

Figure D.4: *Causes for the failure of tap changer*

Core:

The core is the active part of a transformer, and their function is to carry magnetic flux. The laminated cores are used to reduce eddy-current. The causes for the laminated core failures are shown in Figure D.5.

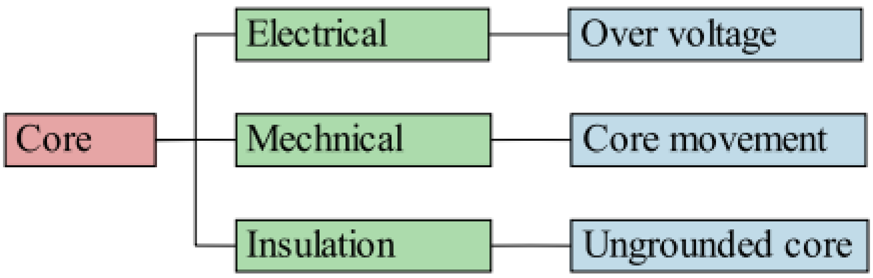

Figure D.5: *Causes for the failure of core*

Cooling System:

The cooling system reduces the heat produced in transformers due to copper and iron losses. The cooling system consists of cooling fans, oil pumps, and water-cooled heat exchangers. The failure in the cooling system causes the heat to build up in the transformer which effects different parts of the transformer and also causes more gas pressure to be built inside which may cause the transformer to blow. Some of the main factors for transformer cooling system failure are shown in Figure D.6.

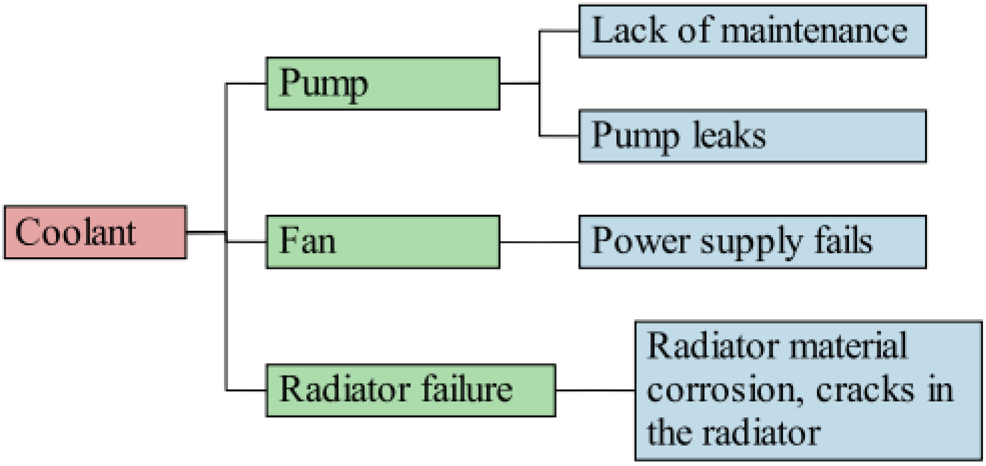

Figure D.6: *Causes for the failure of cooling system*

Tank:

The function of the tank in the transformer is to be a container for the oil used in it. Moreover, the tank also used to provide a support structure for all power transformer accessories and control equipment. The causes for the failure of transformer tank are shown in Figure D.7.

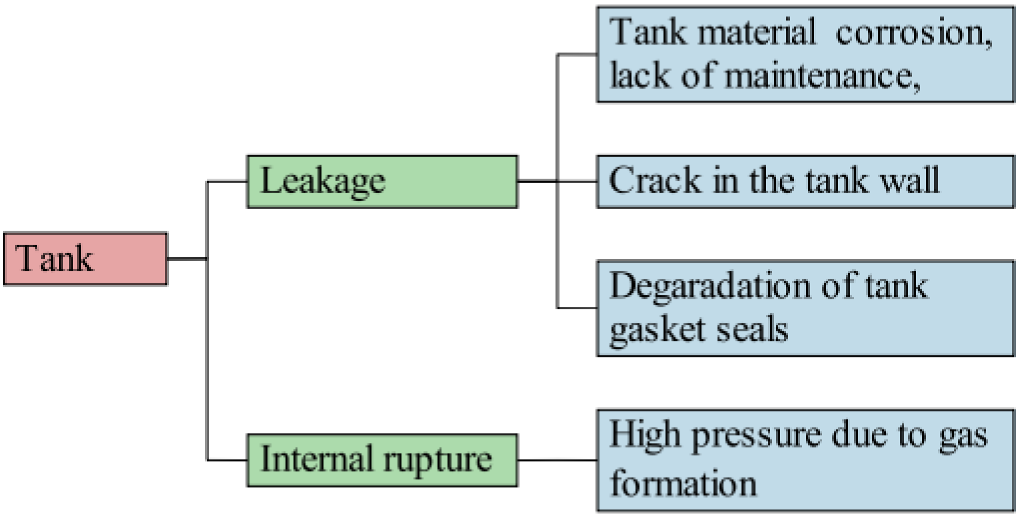

Figure D.7: *Causes for the failure of tank*

Others:

Operational errors, lack of maintenance, and protection system trips/failures are the major factors contributed to the failure of power transformers which is shown in Figure D.8. Operational errors are due to lack of experience, lack of skill on power transformers, work stress and in adequate technical education and training. Lack of maintenance is mainly due to absence of advanced/updated maintenance procedures and lack of spare parts at site. Protection systems for the transformer are split into electrical (over current protection, earth fault protection, busbar protection and differential protection) and mechanical include the Buchholz protection, pressure relief valve, surge protection, and Sudden Pressure Relays. Over current protection systems are responsible for the highest number of failures. Earth fault protection (EFP), busbar protection and differential protection are also responsible for a significant number of failures. Low-level oil and dielectric faults cause the Buchholz protection failure. Moisture, heat, and corrosion were the main reasons for the failure of surge protection. Inadequate maintenance and monitoring are the main reasons for failures of protection systems. Lack of relay maintenance, maintenance relay testing, and deviation of protection settings devices are the main reasons for the performance of these systems.

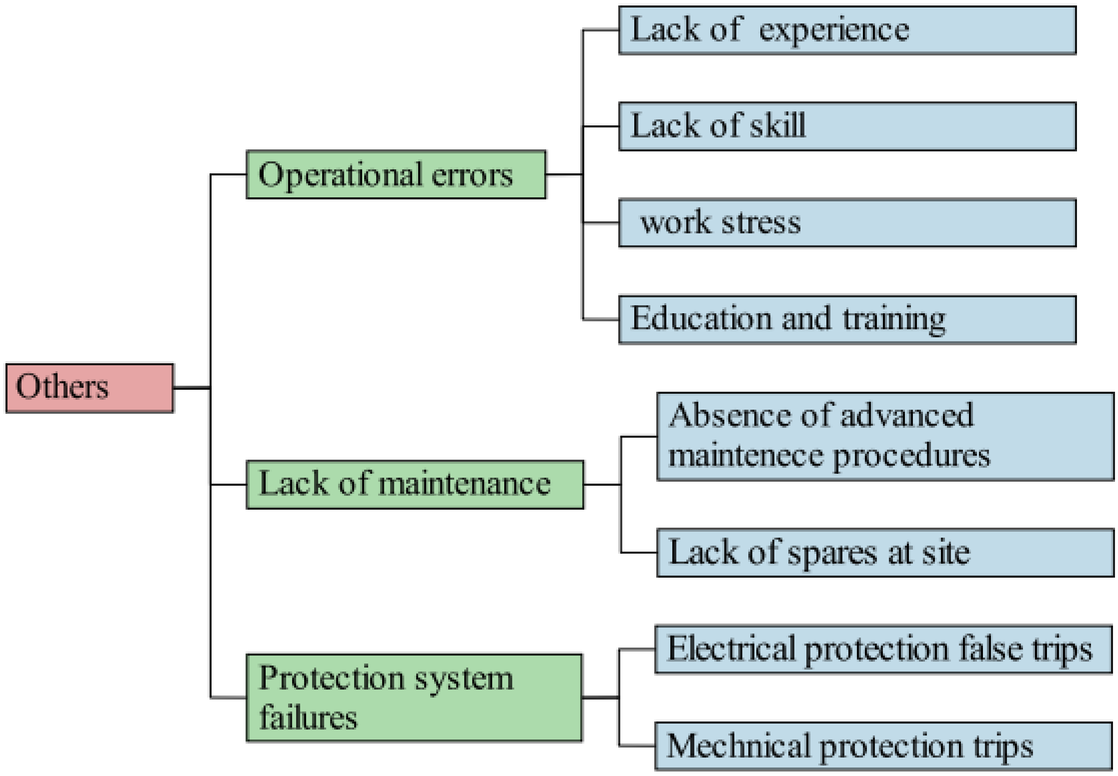

Figure D.8: *Other factors causes for the failure of power transformer component*

People's Democratic Republic of Algeria
Ministry of Higher Education and Scientific Research

University M'Hamed BOUGARA - Boumerdes

Institute of Electrical and Electronic Engineering

Department of Power and Control

Authorization for Final Year Project Defense

Academic year: 2019/2020

The undersigned supervisor: Mohammed Bouchahdane
authorizes the student(s):

Fawzi DJELLOULI ……………………………………Option Power Engineering …………

Abdelkadir DJELLOULI …………………………………Option Power Engineering …………

……………………………………………………………Option……………………………………

to defend ~~his~~ / ~~her~~ / their final year Master program project entitled:

Health Index Assessment of Power Transformer

………

during the [x] June [ ] September session.

Date: 16 /06/ 2020

The Supervisor

Mohammed Bouchahdane

The Department Head

قسم الإلكتروتقني و الآلية

رئيس قسم الالكتروتقني والآلية بالنيابة
أ. معاش